SECTION 3.0 – DSP – INTRODUCTION

3.0.1 FILING REQUIREMENTS

Hydro One Networks Inc. (Hydro One) has prepared a five-year Distribution System Plan (DSP) for the 2023 to 2027 period. This section includes a table of contents, index of tables, and mapping of Chapter 5 of the Filing Requirements (Consolidated Distribution System Plan Filing Requirements), issued on June 24, 2021, to the relevant sections within the DSP.

The DSP provides a consolidated set of documentation concerning Hydro One's distribution system including benchmarking, asset management, performance management, other capital planning factors, the integrated investment planning and customer engagement process, work execution and the resulting capital investment plan for the distribution system. Similar information regarding Hydro One Distribution's General Plant assets may be found in the General Plant System Plan (GSP) under Section 4.0 of the System Plans.

3.0.2 FORMAT OF THE DSP

Consistent with the Filing Requirements, Hydro One's DSP is organized as follows:

DSP Section	Content Description
Section 3.1	Overview – This section provides an overview of Hydro One's distribution system, the factors that were considered in developing the investment plan, and a summary of the investment plan.
Section 3.2	Asset Information and Life Cycle Strategies – This section presents the state of Hydro One's power system assets and their asset management and life-cycle strategies.
Section 3.3	Benchmarking and Other Studies – This section presents the external studies that have been undertaken to inform the investment plan.
Section 3.4	Connecting Distributed Energy Resources – This section provides information on the Distributed Energy Resources (DER), including renewable generation,

	connected to Hydro One's distribution system, along with information on historical and forecast renewable DER connections and capacity.
Section 3.5	Performance Measurement and Outcomes – This section presents Hydro One's approach to performance measurement, including discussion of the distribution scorecards.
Section 3.6	Other Capital Planning Factors and Considerations – This section details other factors which have informed the investment plan, including customer engagement and statutory and regulatory obligations.
Section 3.7	Investment Planning Process – This section summarizes the information found in SPF Section 1.6 – Asset Management and Investment Planning Process as related to Hydro One Distribution.
Section 3.8	Capital Expenditures Overview – This section summarizes Hydro One's capital investment plan for its distribution system for the five-year forecasting period (2023-2027).
Section 3.9	Capital Expenditures Trends and Variances – This section compares Hydro One's historical Distribution capital spending to previous OEB-approved funding and provides a ten-year snapshot (2018 – 2027) of Hydro One's capital spending for its Distribution business.
Section 3.10	Capital Work Execution Strategy – This section discusses the capital delivery process and Hydro One's approach to accomplish the proposed capital investment plan.
Section 3.11	Material Investment Summary Documents – This section includes detailed summaries of large investments (with forecast spending over $1M in any given year) over the 2023-2027 forecasting period in the OEB's System Access, System Service and System Renewal investment categories.

To assist parties in their review of the DSP, Hydro One has prepared a Table of Contents and Concordance found at Appendix 'A' which aligns the sections of this DSP with the Filing Requirements.

Unless otherwise specified, the asset information contained in this DSP is taken as of December 31, 2020. Forecast costs for the 2023-2027 forecasting period are as forecast in Hydro One's 2022-2027 Distribution Business Plan (as presented in Exhibit A-03-01-01).

1 **APPENDIX 'A' – TABLE OF CONTENTS AND CONCORDANCE**

Hydro One Reference	OEB Filing Requirements
3.0 Distribution System Plan	
3.1 – DSP – Overview	
3.1.1 Introduction	5.2.1
3.1.2 Distribution System and Service Area	5.3.2 a), b)
3.1.3 Summary of the DSP Capital Investment Plan	5.2.1, 5.4
3.1.4 The DSP is Reasonable and Appropriate	5.2.1, 5.3.1, 5.3.2 , 5.4, 5.4.1
3.2 – DSP – Asset Information and Life Cycle Strategies	
3.2.1 Introduction	
3.2.2 Asset Component Information – Distribution Stations	5.3.2
Asset Description/Purpose	5.3.2
Asset Demographics, Condition and Other Factors	5.3.2 c), d)
Asset Life Cycle	5.3.3 a), b)
3.2.3 Asset Component Information – Distribution Lines	5.3.2
Asset Description/Purpose	5.3.2
Asset Demographics, Condition and Other Factors	5.3.2 c), d)
Asset Life Cycle	5.3.3 a), b)
3.2.4 Asset Component Information – Wholesale Revenue & Retail Meters	5.3.2
Asset Description/Purpose	5.3.2
Asset Demographics, Condition and Other Factors	5.3.2 c), d)
Asset Life Cycle	5.3.3 a), b)
3.3 – DSP – Benchmarking and Other Studies	
3.3.1 Guidehouse and First Quartile Distribution Poles Replacement Program Benchmarking Report 2020	5.2.3 a)
3.3.2 Guidehouse and First Quartile Distribution Station Refurbishment Benchmarking Report 2020	5.2.3 a)
3.3.3 CNUC Hydro One Vegetation Management Study	5.2.3 a)
3.3.4 ClearPath OCP First Cycle Performance Assessment	5.2.3 a)
3.3.5 Trilliant Correspondence on Expected Service Life for Meters	5.2.3 a)
3.3.6 Hydro Quebec Accelerated Life Testing of Meters	5.2.3 a)
3.3.7 Guidehouse and First Quartile AMI Benchmarking	5.2.3 a)
3.3.8 ISG Billing and Call Centre Benchmarking	5.2.3 a)
Attachments: Benchmarking Studies	
Attachment 1 – Guidehouse and First Quartile	

Hydro One Reference	OEB Filing Requirements
Distribution Poles and Substations Benchmarking	
Attachment 2 – CNUC Hydro One Vegetation Management Study	
Attachment 3 – ClearPath OCP First Cycle Performance Assessment	
Attachment 4 – Trilliant Correspondence on Expected Service Life for Meters	
Attachment 5 – Hydro Quebec Accelerated Life Testing of Meters	
Attachment 6 – Guidehouse and First Quartile AMI Benchmarking	
Attachment 7 – ISG Billing and Call Center Benchmarking	
Attachment 8 – Smart Meter Efficiency Report	5.2.4
3.4 – DSP – Connecting Distributed Energy Resources	
3.4.1 Overview	
3.4.2 Renewable Applications	5.3.4 a)
3.4.3 Connection Forecast	5.3.4 b)
3.4.4 Capacity and Constraints	5.3.4 c) – e)
3.4.5 REG Investments	5.2.2 d)
Attachments:	
Attachment 1 – Hydro One Letter Summarizing Participation in IESO Regional Planning Activities	
3.5 – DSP – Performance Measurement and Outcomes	
3.5.1 Introduction	
3.5.2 Distribution Scorecard	5.2.3 a) – d)
3.5.3 Hydro One Distribution OEB Scorecard	5.2.3 a) – d)
3.5.4 Discussion of APB Results	
Attachments:	
Attachment 1 – OEB Appendix 5-A Metrics	
3.6 – DSP – Other Capital Planning Factors and Considerations	
3.6.1 Introduction	
3.6.2 How the Capital Plan Reflects Customer Engagement	5.2.1 b), 5.4 a)
3.6.3 How the Capital Plan Reflects Regional Planning, Regulatory Compliance, & System Modernization	5.2.2
3.6.4 How the Capital Plan Addresses Distribution System Losses	
3.7 – DSP – Investment Planning Process	
3.7.1 System Planning Process Phases	5.3.1 b)

Hydro One Reference	OEB Filing Requirements
3.7.2 Strategy and Context	5.3.1 a)
3.7.3 Asset Management Process	5.3.1 b), 5.4 a), 5.4.1
3.7.4 Investment Planning Process	5.2.1 b), 5.3.1 b), 5.4 a), 5.4.1
3.8 – DSP – Capital Expenditures - Overview	
3.8.1 Introduction	
3.8.2 Capital Investment Plan	5.4.2, 5.4.3.1
3.8.3 Impact of Capital Investments on OM&A Expenditures	5.3.3 a), 5.4.2, 5.4.3.1
3.9 – DSP – Capital Expenditures – Trends and Variances	
3.9.1 Introduction	
3.9.2 Historical Capital Expenditures Trends and Variances	5.4.2, 5.4.3.1
3.9.3 Forecast Capital Expenditures	5.4.2, 5.4.3.1
Attachments:	
Attachment 1 - Dx Chapter 2 Appendix 2-AB - Capital Expenditures	
Attachment 2 – Capital Program Performance Report 2019 to 2020	
Attachment 3 – Acquired Utilities	
3.10 – DSP – Capital Work Execution	
3.10.1 Introduction	
3.10.2 Capital Delivery Process	5.3.3 a)
3.10.3 Project Oversight	5.3.3 a)
3.10.4 Factors Impacting Work Execution	5.3.3 a)
3.10.5 Safety	5.2.3
3.10.6 Productivity and Continuous Improvement	5.2.1 c)
3.11 – DSP – Material Investment Summary Documents	5.4.2, 5.4.3.2
D-SA-01 Joint Use and Relocations	
D-SA-02 New Load Connections, Upgrades, Cancellations	
D-SA-03 Customer Demand Distributed Energy Resources	
D-SA-04 Metering Sustainment	
D-SR-01 Distribution Stations Demand Capital Program	
D-SR-02 Mobile Unit Substation Program	
D-SR-03 Distribution Station Planned Component Replacement Program	
D-SR-04 Distribution Station Refurbishment	
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response Program	

Hydro One Reference	**OEB Filing Requirements**
D-SR-06 Distribution Lines PCB Equipment Replacement Program	
D-SR-07 Pole Sustainment Program	
D-SR-08 Distribution Lines Minor Component Replacement Program	
D-SR-09 Submarine Cable Replacement Program	
D-SR-10 Distribution Lines Sustainment Initiatives	
D-SR-11 Life Cycle Optimization & Operational Efficiency Projects	
D-SR-12 Advanced Meter Infrastructure 2.0 (AMI 2.0)	
D-SS-01 System Upgrades Driven by Load Growth	
D-SS-02 Reliability Improvements	
D-SS-03 Demand System Modifications	
D-SS-04 Energy Storage Solutions	
D-SS-05 Worst Performing Feeders	
D-SS-06 Power Quality and Stray Voltage	

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SECTION 3.1 – DSP – OVERVIEW

3.1.1 INTRODUCTION

Hydro One has prepared a comprehensive five-year DSP for the 2023 to 2027 period. The DSP presents a portfolio of capital investments that have been prioritized based on an outcomes-driven and customer-focused investment planning framework, in alignment with the principles and expectations articulated by the OEB in its RRF.[1]

The capital investments outlined in this DSP have been selected to meet pressing distribution asset and system needs and customer service imperatives. To meaningfully reflect customer needs and preferences, Hydro One undertook an extensive, two-phase customer engagement process that directly informed the planning process and integrated customer input into the development of the plan. The resulting DSP is based on outcomes that customers value, and is consistent with their priorities and pacing preferences.

Approval of this Application results in the following bill impacts on a distribution-only basis: the estimated total monthly bill impact for a typical Hydro One medium density (R1) residential customer (750 kWh/month)[2] is a decrease of 1.8% ($2.78) in 2023 and an average annual increase of 0.8% ($1.29) on monthly bills over the Application period. For a typical Hydro One GSe< 50 kW customer (2,000 kWh/month) the estimated total monthly bill impact is a decrease of 2.0% ($8.32) in 2023 and an average annual increase of 0.7% ($2.92) on monthly bills over the Application period. Detailed bill impacts are provided in Exhibit L-06-01.

With approximately 1.4 million residential, commercial, industrial and LDC customers across a vast geographic area encompassing urban, rural and remote communities, Hydro One’s distribution system is essential infrastructure for Ontario. Given the breadth of its service

[1] OEB, Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012.
[2] Typical Hydro One R1 customer without Distribution Rate Protection per O.Reg 198/17.

territory, Hydro One must ensure safe and reliable distribution of power and adequate capacity in concentrated urban areas, low density rural areas, and remote locations connected by long feeders over diverse and challenging terrain and vegetation. Based on this overarching service mandate, the proposed DSP reflects a portfolio driven by multiple and wide-ranging customer needs, including assets in poor condition that need renewal, areas of the system requiring reliability improvement, and non-discretionary obligations such as load and generation connections and storm response.[3] In particular, non-discretionary investments total $1,824M and make up 34% of the total distribution capital envelope of $5,297M over the 5 year period.[4]

Over the five-year period, $2,267M or 43% of the total DSP portfolio is System Renewal, of which, 27% is mandatory or demand-driven renewal spend (e.g., replacement of failing or failed station assets, DSP Section 3.11, D-SR-01; lines trouble call and storm damage response, DSP Section 3.11, D-SR-05; and PCB equipment replacement, D-SR-06). Significant drivers include:

- the Advanced Metering Infrastructure 2.0 (AMI 2.0) deployment ($558M, DSP Section 3.11, D-SR-12) needed to replace Hydro One's legacy AMI 1.0 system deployed in 2007 and now experiencing increasing meter failures and maintenance costs and which is at the end of its service life.
- Poor condition distribution poles that have high reliability impacts on customers if not replaced or refurbished ($563M, DSP Section 3.11, D-SR-07).

The remaining $534M of System Renewal (10% of the DSP), net of the mandatory or demand-driven renewal spend, targets a portion of the large population of poor condition assets that

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[3] In accordance with the Filing Requirements, Hydro One does not have any transmission or high-voltage assets deemed by the OEB as distribution assets and therefore is not seeking approval for any such assets in this application.

[4] Joint Use and Relocations ($135M, DSP Section 3.11, D-SA-01); New Load Connections, Upgrades, Cancellations ($793M, DSP Section 3.11, D-SA-02); Connecting Distributed Energy Resources ($7M, DSP Section 3.11, D-SA-03); Metering Sustainment ($189M, DSP Section 3.11, D-SA-04); Distribution Stations Demand Capital Program ($32M, DSP Section 3.11, D-SR-01); Distribution Lines Trouble Call and Storm Damage Response Program ($552M, DSP Section 3.11, D-SR-05); Distribution Lines PCB Equipment Replacement Program ($28M, DSP Section 3.11, D-SR-06); Demand Investments ($68M, DSP Section 3.11, D-SS-03); and Stray Voltage ($20M, DSP Section 3.11, D-SS-06)

pose the highest risk on the distribution system, including poor condition transformers and other station equipment and line assets (including deteriorated and hard to access off-road line sections).

System Service accounts for about $994M or 19% of the total DSP portfolio over the five-year period. System Service investments are required to modify Hydro One's distribution system to address capacity or operational constraints or make targeted reliability improvements in much needed areas. Notably, Hydro One needs to make significant investments to:

- accommodate anticipated load growth (including in the Leamington area where load is expected to double in five years) ($478M, DSP Section 3.11, D-SS-01),
- address worst performing feeders through automation/sectionalization ($209M, DSP Section 3.11, D-SS-05) or feeder ties ($40M, DSP Section 3.11, D-SS-02), and
- improve reliability for customers experiencing significant outages through energy storage solutions ($177M, DSP Section 3.11, D-SS-04).

Material Distribution investments and the main customer benefit or outcome associated with each investment have been summarized in Table 1 below.

Table 1 - How Customers are impacted by spend in the 2023-2027 plan period

Investment/Description	Need	Main Customer Benefits/Outcomes
System Renewal Investments		
Pole Sustainment Program (D-SR-07) – Replacing 51,500 wood poles (66%) and refurbishing an additional 14,000 (18%) of poor condition wood poles.	Renew poor condition assets to maintain the overall health of the system.	Wood poles are the backbone of the overhead distribution system, and are integral in delivering electricity safely and reliably across the Province to our 1.4 million customers. Continued investment in replacing poor condition wood poles is necessary to maintain the overall health of the system and reduces the reliability impacts to customers due to interruptions.
Distribution Station Refurbishment (D-SR-04) & Lifecycle Optimization & Operational Efficiency Projects (D-SR-11) – Replacing 118 distribution station transformers in poor condition.		Distribution station transformers play a key role in the safe and reliable delivery of power to distribution customers. Whereas a pole failure can be localized, a station transformer failure will interrupt power to all customers connected to that

Investment/Description	Need	Main Customer Benefits/Outcomes
		station. Proactively addressing poor condition station transformers, is expected to mitigate transformer failures and maintain the reliability of the distribution system.
Advanced Meter Infrastructure 2.0 (AMI 2.0) (D-SR-12) – Replacing AMI 1.0 (1.4 million smart meters) with a modern AMI platform. Approximately 45% of the total meter population is projected to fail by the end of the plan period.	Renew the smart meter fleet to meet regulatory requirements, and to address escalating failures arising from meters that are at EOL or will reach EOL over the plan period.	Customers expect and will continue to receive the same high level of billing accuracy. This investment ensures that customers continue to stay connected to safe reliable power, while enabling greater access to flexible service options. The modern platform, through improved network communications, will enhance end-to-end protection of customer data, while also enabling customer tools to help manage energy usage and bills.
System Access Investments		
New Load Connections, Upgrades, Cancellations (D-SA-02) – Enable	Facilitating system capacity needs driven by load growth.	In addition to residential customers, Hydro One supplies Ontario's major

Investment/Description	Need	Main Customer Benefits/Outcomes
connections (approximately 18,000 annually) of new load customers and to upgrade supply capacity (approximately 4,500 annually) of existing load customers to the distribution system.		commercial and industrial businesses, as well as over 60 Local Distribution Companies (LDCs). Our customers are diverse, have significant power requirements and have unique connection needs.
System Service Investments		
System Upgrades Driven By Load Growth (D-SS-01) – Enable capacity through system upgrades and or modifications resulting from large scale regional load growth.		Communities across Ontario are growing and Hydro One is obligated to provide the distribution system capacity to meet that demand.
Reliability Improvements (D-SS-02) & Worst Performing Feeders (D-SS-05) – Creation of new feeder ties; deployment of modern switching; enabling remote switching capabilities; and the installation of communicating faulted	Improving reliability through grid modernization initiatives and energy storage solutions.	Reliable power is essential to our customer's daily lives, businesses and productivity. Grid modernization leverages modern technology solutions (i.e. remote switching, sensors, communicating fault indicators, and energy storage) to reduce the

Investment/Description	Need	Main Customer Benefits/Outcomes
circuit indicators. **Energy Storage Solutions (D-SS-04)** – Targeted installations of centralized and residential battery energy storage solutions.		impact and duration of power outages; thereby minimizing disruptions to the daily lives of our customers, businesses and communities. Customers (600,000) are expected to benefit from feeder level reliability improvement investments. Customers that benefit from feeder level investments are expected to see a reduction in the duration of outages by an average of approximately 40%. For our northern First Nations and rural or northern communities, where traditional reliability solutions are inadequate or not cost effective, centralized energy storage and residential battery back-up are expected to the reduce outage duration and frequency by up to 60%.

Hydro One's robust investment planning process coupled with its mature capital delivery process has enabled the Company to successfully deliver large capital work plans and reduce the variability of capital expenditures and in-service additions. Given the mandatory and demand-driven work forming a large portion of the DSP, Hydro One's rigorous redirection process (see SPF Section 1.7) will govern necessary funding adjustments to appropriately accommodate emerging needs. On this basis, Hydro One is confident in its ability to carry out the proposed capital plan and continue a demonstrated track record of successful execution.

3.1.2 DISTRIBUTION SYSTEM & SERVICE AREA

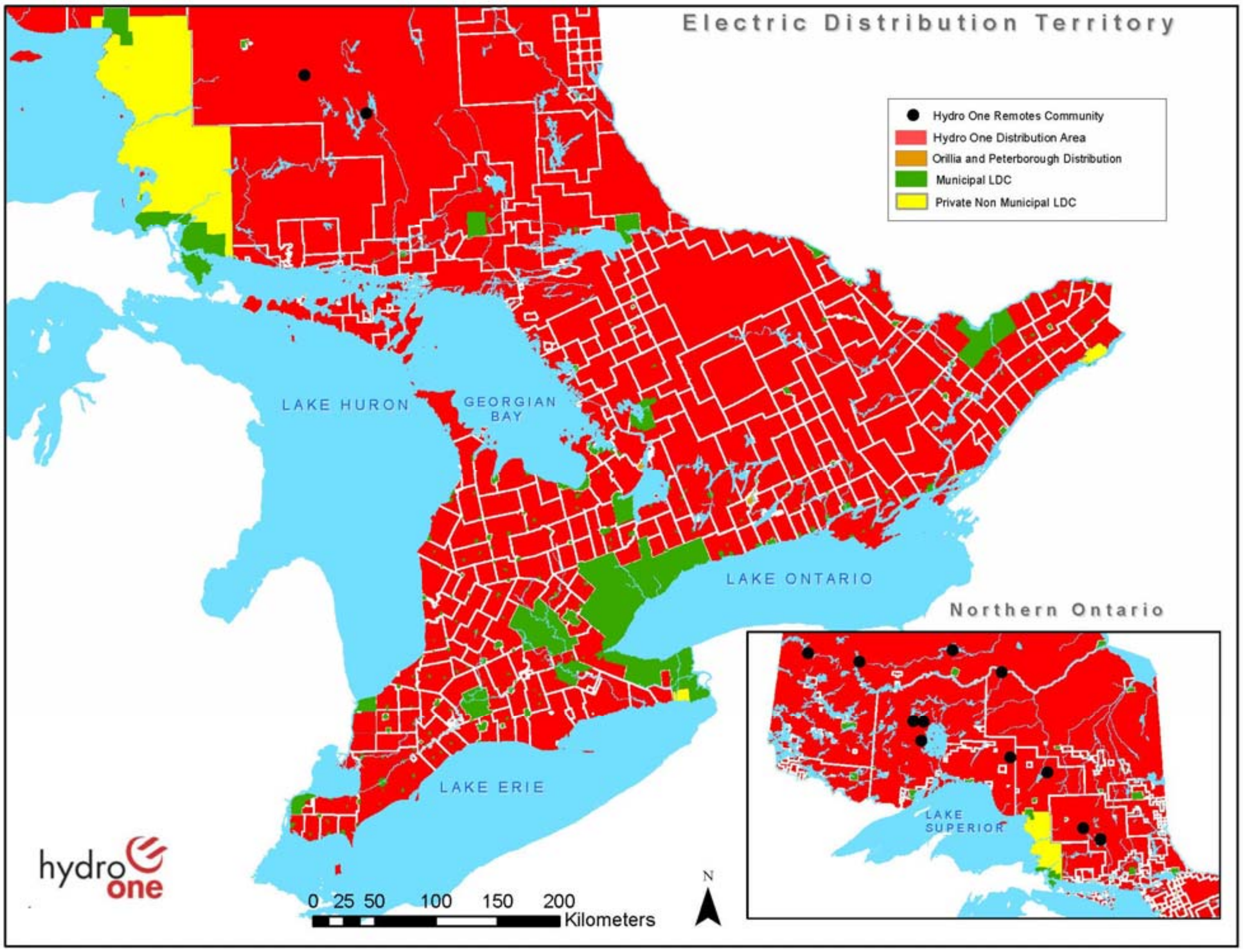
Hydro One's distribution system and business are best characterized as diverse. As a result of that diversity and the operational challenges that come with it, Hydro One's capital and operational plans must meet those challenges and the appropriateness of those plans should be considered from the uniqueness of that perspective. Because of Hydro One's legacy of Ontario's distributor of last resort and its inclusion over time of additional urban areas to its service territories, unlike any other distributor in Ontario, Hydro One's service territory extends across the province to serve 1.4 million residential, commercial, industrial, and LDC customers by employing more than 123,000 of distribution circuit kilometers over a vast area of the province with varying customer densities, regional needs (such as geography, terrain, forestry, weather patterns, and load growth) and distribution voltages. In addition to end-use customers, Hydro One also has successfully integrated approximately 3,200 MW of distributed energy resources (DER) into the distribution system, and continues to support new customer requests within current regulatory frameworks, together with the numerous technical considerations that must be carefully assessed to ensure system performance is unaffected.

The key statistics for distribution assets owned and operated by Hydro One are summarized in Table 2 below.

Table 2 - Hydro One Distribution System Assets – Key Statistics

System Assets	Total
Number of Customers (including acquired utilities)	~1.4M
Operating Centres	54
Distribution Poles (Total Number)	~1.6M
Length of Overhead Distribution Lines (Total Circuit km)	~113,000
Length of Underground Distribution Cables (Total Circuit km)	~10,000
Distribution Stations (including Regulating Stations)	~1,000
Distribution Service Transformers	~522,000

Hydro One's vast distribution service area is shown in Figure 1 below.



1 **Figure 1: Map of Hydro One Distribution Service Territory**

The size, scope and density of Hydro One's distribution system impact the work programs (and associated cost requirements, service imperatives, and operational challenges) that must be undertaken across the province to sustain safe and reliable system operations and customer service. For example, much of the distribution system is designed with a radial supply configuration. This design has advantages in terms of cost-effectively serving low customer density areas over long distances. In contrast to the dual-supply design of most Hydro One transmission delivery points, a largely radial distribution grid means that customer load is interrupted when an equipment outage occurs. Rural distribution feeders serving remote northern customers (excluding those served by Hydro One Remote Communities Inc.) – including First Nations communities – are even longer than an average feeder, sometimes as long as 100 km, rendering such long distance feeders particularly vulnerable to interruptions and prolonged outages.[5] Poor reliability is not merely an inconvenience for these communities, it also poses real challenges for everyday life and serious health and safety risks, especially during harsh weather conditions or the current COVID-19 pandemic.

In addition, much of Hydro One's distribution system was built in the 1950s and 1960s, meaning many assets are approaching or are beyond their expected service life. Based on asset condition data there are a significant population of poor condition distribution assets on the system that are subject to elevated failure risks. The population of poor condition assets include 237 distribution station transformers (or about 20% of the fleet) and approximately 79,000 wood poles (or 5% of the fleet). Targeted and proactive renewal is required to maintain the overall health of the distribution system to avoid continued deterioration.

Work challenges for both capital and maintenance activities are created by the low density and long reach of Hydro One's distribution facilities. For instance, crews must travel long distances to visit relatively few customers for failed meter replacements or for vegetation clearing. This sets Hydro One apart from most other North American distributors (e.g., see vegetation

[5] The reliability challenges faced by northern communities are further discussed in Exhibit A-07-02, Appendix A (First Nations Reliability Report).

management benchmarking study in DSP Section 3.3, Attachment 2 and AMI replacement benchmarking study in DSP Section 3.3, Attachment 6). Moreover, the distribution system is susceptible to a variety of extreme weather conditions (e.g., blizzards, hail, ice storms, lightning, extreme wind) in different parts of the service territory at different times. Such events are impossible to predict from year to year, present logistical challenges and require significant resources devoted to the timely restoration and post-event asset repairs or replacements.

The foregoing factors can have a significant impact on work program costs that Hydro One must manage while meeting the needs of customers across the province.

3.1.3 SUMMARY OF THE DSP CAPITAL INVESTMENT PLAN

From 2023 to 2027, Hydro One plans to invest $5,297M in the distribution system. These investments are shaped by a range of inputs and considerations, including customer engagement, regional planning, benchmarking, productivity and performance management, asset condition, grid modernization initiatives, and system capacity needs.

The outcomes for customers, aligned with customer needs and preferences, from these investments include:

- Asset stewardship and the prevention of asset degradation through appropriately paced replacement of poor condition assets
- Improved long-term reliability across the distribution system, with a focus on customers and communities with exceptionally poor reliability through grid modernization and new technology deployments
- Community growth facilitated by supplying capacity needs
- Regulatory compliance with mandated requirements

Table 33 and Figure 2 summarize the capital investments planned for the 2023-2027 period, by OEB category:

1 **Table 3 - Planned capital expenditures under the DSP for the period of 2023-2027**

OEB Investment Category	Forecasting Period ($M)				
	2023	2024	2025	2026	2027
1.System Access	239.6	240.6	227.0	212.6	204.3
2.System Renewal	373.1	410.3	494.2	491.5	497.8
3.System Service	196.5	169.7	229.6	192.0	205.9
Subtotal Categories 1, 2, and 3	**809.2**	**820.6**	**950.7**	**896.1**	**908.0**
4.General Plant (Distribution)[6]	195.9	207.4	170.1	175.5	162.9
Total Distribution Capital	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**
System O&M[7]	**$597.5**	**-**	**-**	**-**	**-**

[6] Details on General Plant expenditures are provided in GSP Section 4.1.
[7] System O&M reflects total Operations, Maintenance and Administration expenses. Further information is provided in Exhibits E-03-01. System O&M in years 2024 - 2027 will be determined based on the factors identified in Exhibit A-04-03.

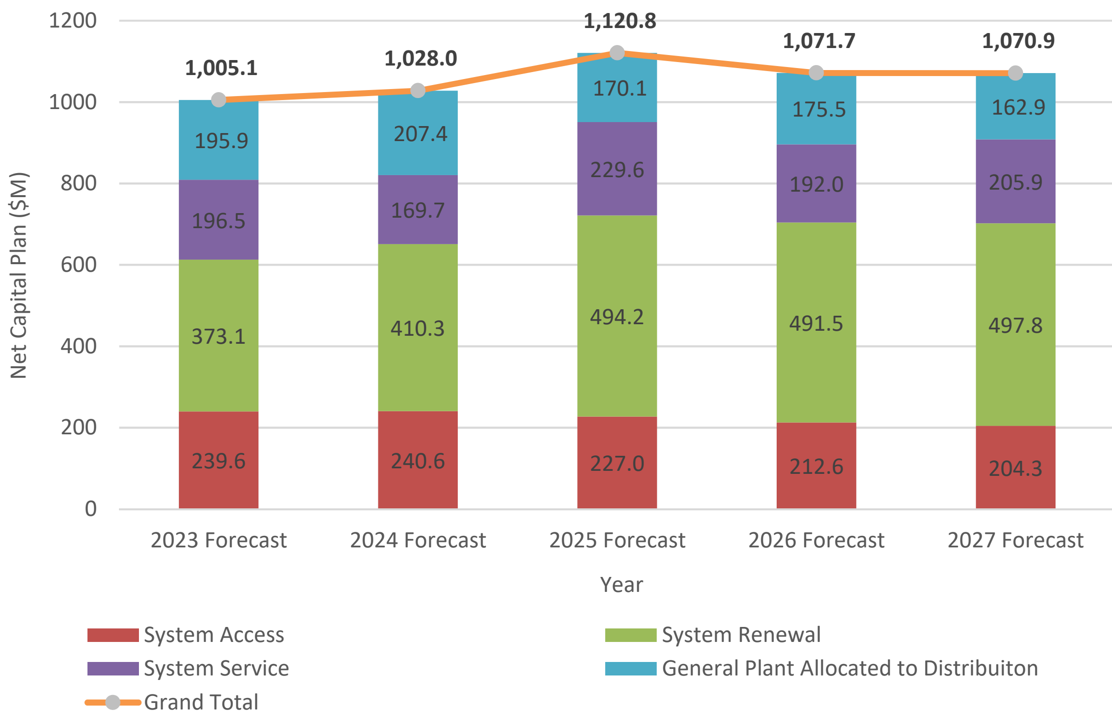
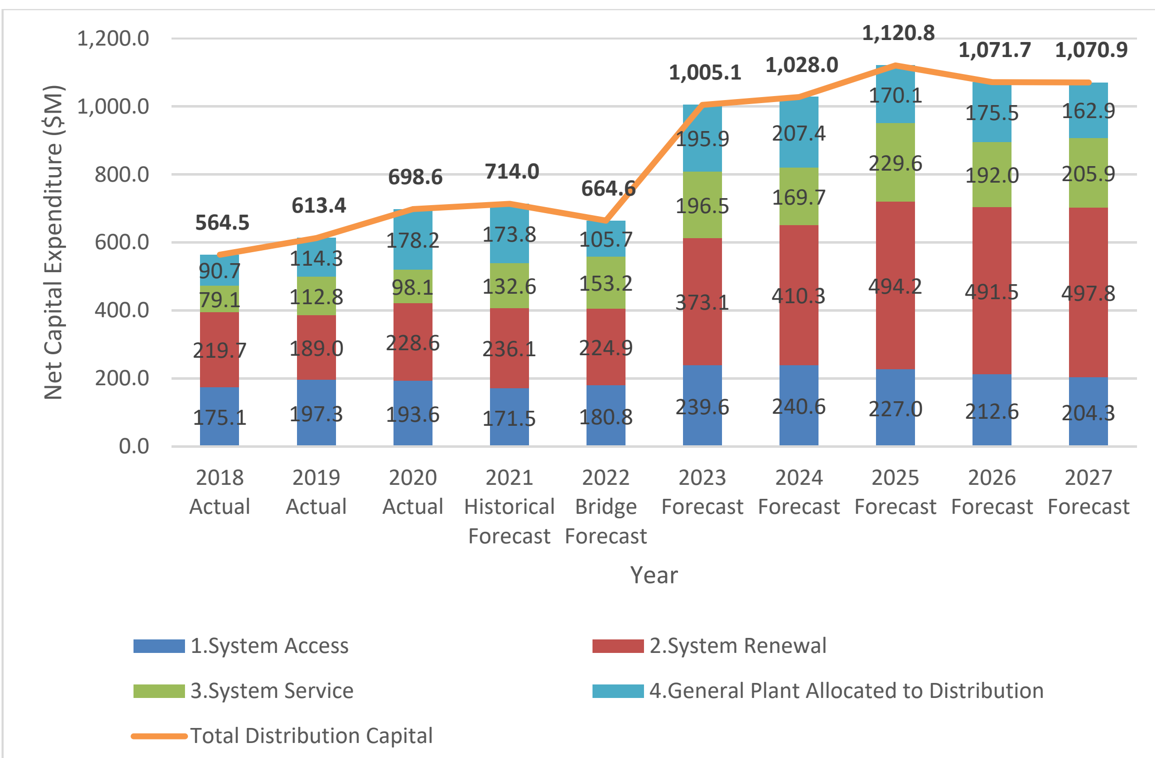


Figure 2: Forecast Period Capital Investment Summary

The specific outcomes addressed by each program and project are detailed in the respective Investment Summary Documents (ISD) filed at DSP Section 3.11.

As described in DSP Section 3.9, planned investments over the 2023-2027 period reflect an increase of approximately 63% over actual and forecast capital expenditures for the current planning period (2018-2022). This increase is not the consequence of one particular circumstance. It is because of a variety of needs that must be met for a safe and reliable distribution system. The largest contributor to the increase in forecast investments is the need to renew poor condition assets or assets that are at the end of their service life – the increase in System Renewal for the 2023-2027 period relative to the actual and forecast capital expenditures for the current planning period (2018-2022) is 106%. Hydro One will replace assets that pose the highest reliability risk, including poles, line sections, and distribution stations. In addition, Hydro One must renew its smart meter fleet to satisfy regulatory requirements, and to address escalating failures arising from deteriorating smart meters that are at end of their service life or will reach end of their service life over the plan period. Capacity needs in areas of load growth must also be addressed. Investments in grid modernization and energy storage technologies are required to address reliability needs stemming from the system's long-distance feeder configuration.

Figure 3 below shows historical and forecast expenditures for the 2018-2022 period and proposed expenditures for the 2023-2027 period Details about the variances between the 2018-2022 OEB-approved levels of capital spending and the actual and forecasted expenditures can be found in DSP Section 3.9. [8]



[8] Hydro One's 2018 expenditures align exactly with forecast expenditures due to the timing of the OEB's Decision and Order in EB-2017-0049 (issued in March 2019), and as such are not generally included in the variance explanations.

Figure 3: Historical and Forecast Capital Expenditures

3.1.4 SYSTEM ACCESS INVESTMENTS SUMMARY

System Access investments are mandatory and non-discretionary and represent 21% of the total capital portfolio in the forecast period. Investments in this category are driven by statutory, regulatory or other obligations that Hydro One must meet to provide access to the distribution system. Primarily, investments relate to customer requests for connection or a connection modification, but investments can also include the relocation of system assets to accommodate municipal infrastructure development or modifications.

Key outcomes of System Access Investments:

- Fulfill customer requests for new connections, upgrades, or cancellations
- Fulfill third party requests for joint use attachments
- Replace failed meters to maintain customer billing reliability

The most significant investments in this category are New Load Connections, Upgrades, and Cancellations (DSP Section 3.11, D-SA-02) and Metering Infrastructure Sustainment (DSP Section 3.11, D-SA-04), which together represent more than 87% of all System Access expenditures.

- **New Load Connections, Upgrades, and Cancellations (D-SA-02)** represents the largest system access expenditure, totaling $793M over the 2023-2027 period. Hydro One adds thousands of new connections to its distribution system every year in compliance with its obligations under section 28 of the *Electricity Act, 1998* and the Distribution System Code. For customers that require expansion of the network in order to be connected, a discounted cash flow calculation is used to determine customer contributions. The customer's capital contribution is based on any shortfall between future revenues and the cost of connection and system expansion. Future revenues credited to customer connections or capital contributions from connecting customers (if needed) offset capital expenditures to constitute net capital, which is added to Hydro One's rate base when the assets are placed in-service. Service cancellations involve customers who request disconnection from the distribution system, or connection assets that are unused for a prolonged period of time, i.e. vacant premises. Hydro One removes idle assets, such as transformers, poles, service wires and meters for safety and security reasons. Details of the costs associated with customer connections, upgrades, and cancellations can be found in DSP Section 3.11, D-SA-02. Expenditures for the design and construction of new and upgraded connections will increase approximately 10% throughout the forecast period, which is a result of anticipated volumes based on the load forecasting methodology described in Exhibit D-05-01.

- **Metering Infrastructure Sustainment (D-SA-04)** consists of expenditures for retail and wholesale revenue metering totalling $189M over the forecast period. These expenditures support Hydro One's obligations to meet regulatory requirements under the *Electricity and Gas Inspection Act*, the *Weights and Measures Act*, the OEB's Distribution System Code, and the IESO's Market Rules. Approximately 97% of the total expenditures relate to retail revenue metering and the need to satisfy regulatory requirements for meter sampling and the replacement of failing AMI 1.0 meters that are in poor condition. Metering Infrastructure Sustainment costs peak in 2023 at $63M and steadily decline to $9M in 2027 as AMI 2.0 meters are installed (see DSP Section 3.11, D-SR-12). The remaining Wholesale Revenue Metering expenditures (approximately 3% of total) are relatively consistent and address IESO market rule reporting requirements, meter reverification, corrective and preventative maintenance.

A complete listing of System Access investments can be found within ISDs, which are attached to DSP Section 3.11.

3.1.5 SYSTEM RENEWAL INVESTMENTS SUMMARY

Over the 2023-2027 period, planned System Renewal investments are critical to address the growing population of distribution assets that are in poor condition. Failure to renew these assets over the 2023-2027 period will pose an ever-increasing reliability risk. While these renewal investments vary in cost and scope, the unique needs that each address are set out in DSP Section 3.11, along with detailed descriptions of each investment.

The largest planned investments in System Renewal programs are in the Pole Sustainment program (DSP Section 3.11, D-SR-07) and Advanced Meter Infrastructure 2.0 (DSP Section 3.11, D-SR-12), both of which are highlighted below:

- The **Pole Sustainment Program (D-SR-07)** includes planned expenditures of $563M over the forecast period. Pole sustainment constitutes about 25% of the total system renewal envelope. Based on their condition (determined by actual condition assessments), Hydro One is planning to test and treat approximately 515,000 poles, refurbish approximately 14,000 poles,[9] and replace about 51,500 poles over the planning period. The pole replacements address approximately 3% of the 1.6M pole population and 67% of 79,000 poor condition poles. Details on Hydro One's pole testing and replacement strategy, including details on the rationale, timing, and scope of the program can be found in DSP Section 3.2 as well as in DSP Section 3.11, D-SR-07.

- The **AMI 2.0 Program (D-SR-12)** is the planned replacement of Hydro One's legacy AMI 1.0 system. Hydro One forecasts expenditures of $558M for this investment in the 2023-2027 period. The AMI 1.0 system comprises approximately 1.4M meters, of which approximately 840,000 are between 11-13 years old and will soon reach the end of their expected 15-year service life. Manufacturer service life attestations, benchmarking studies, independently conducted Accelerated Life Testing (ALT) of meters, and trends in increasing meter failures all support an approximately 15-year service life for AMI 1.0 meters. Significantly, the ALT study found critical failures in meters involving the rapid degradation of the capacitor that enables meters to reliably communicate. Based on these findings, close to 579,000 meters are projected to fail by the end of the test period in 2027. The physical deterioration of meter components and meter failures pose impacts and critical risks to Hydro One affecting various elements of its business including:

[9] The test and treat and pole refurbishment programs are new programs introduced in 2021.

- Reduced billing reliability and resultant customer dissatisfaction from estimated billing and billing corrections;
- Increasing costs associated with reactive individual meter replacements as a result of failed meters;
- Higher labour costs for unplanned individual failed meter replacement relative to mass meter replacement;
- Replacement of failed meters with obsolete technology, and the associated lost opportunities for future benefits that address foreseeable needs; and
- Regulatory non-compliance.

Additional details on the rationale, timing, and scope of the AMI 2.0 program investment can be found in DSP Section 3.2 and in DSP Section 3.11, D-SR-12.

A complete listing of System Renewal investments can be found within the ISDS, which are attached to DSP Section 3.11.

3.1.6 SYSTEM SERVICE INVESTMENTS SUMMARY

System Service investments are modifications to Hydro One's distribution system to ensure that the system continues to meet operational objectives while addressing anticipated future customer electricity service requirements. Over the 2023-2027 period, System Service investments will increase to meet load growth, address worst performing feeders, and install energy storage to improve reliability for customers where conventional alternatives are not possible or cost prohibitive.

The largest expenditures in this category, representing approximately 75% of the system service envelope, are as follows:

- **Load growth investments (D-SS-01)** investments account for a total of $478M over the forecast period. Load growth investments are critical to ensuring Hydro One's system has sufficient capacity to permit new connections, and to support growing communities.

The Leamington area in particular represents approximately half of all load growth investments, and therefore constitutes the bulk of the variance from historical trends. The Leamington area demand and capacity needs are driven by the growth in agricultural greenhouses. This growth trend is expected to continue throughout the 2023-2027 period, and beyond.

- **Modernization of Worst Performing Feeders (D-SS-05)** investments account for a total of $209M. Hydro One's worst performing feeders program aims to address feeders that are performance outliers, which contribute the most to system SAIDI. These investments align with customer engagement results that indicate clear customer preference to improve reliability through grid modernization.[10]
- **Energy Storage Solutions (D-SS-04)** investments account for a total of $177M over the forecast period. These investments will improve service for customers and communities with exceptionally poor reliability, where reliability performance cannot be meaningfully or cost-effectively addressed through other, more traditional alternatives such as feeder sectionalization. Many of the First Nations communities and residential customers with poor reliability metrics are rural, with the path of electrical supply characterized by distribution feeders that are long, radial, and vulnerable to outages. Hydro One rural distribution feeders can be over 100 kilometres long, with numerous branches and significant off-road sections through heavily forested areas or submarine cables. These radial distribution feeders do not typically have an alternate source of supply and the cause of any outage must be corrected before power can be restored. Rural distribution feeders pose additional challenges for Hydro One staff responding to an outage, for example: rough or off-road terrain, lengthy line sections to patrol that result in increased travel time. These challenges result in prolonged outage durations. The program leverages storage technologies to introduce system resilience directly at the customer site or at the distribution station level, ensuring a temporary source of clean backup power when the upstream supply is lost.

[10] SPF Section 1.6, Attachment 1

A complete listing of System Service investments can be found within the ISDs, which are attached to DSP Section 3.11.

3.1.7 GENERAL PLANT INVESTMENTS – DISTRIBUTION

General plant investments relate to assets that are not part of the electrical distribution system, such as facilities and real estate, transport and work equipment, information technology, and security, but which are required to support both the Transmission and Distribution systems. A specific section has been dedicated to general plant expenditures for this rate filing under the GSP Section 4.8.

3.1.8 THE DSP IS REASONABLE AND APPROPRIATE

The planning basis for the DSP is highlighted below. This includes the outcomes-based planning context, asset management process, and investment planning process. Hydro One's ability to execute the proposed plan is also highlighted. The planning process is detailed in SPF Section 1.6, DSP Section 3.7, and DSP Section 3.10.

3.1.9 PLANNING CONTEXT

Hydro One's robust asset management practices and investment planning process provides customer-centered outcomes in alignment with the OEB's RRF outcomes:

- **Customer Focus:** maintaining and improving power quality and customer reliability in response to identified customer preferences;
- **Operational Effectiveness:** Achieving top-tier safety performance and eliminating serious injuries, improving long-term reliability by modernizing the grid and mitigating risk arising from asset deterioration as well as minimizing long-term costs to maintain the distribution;
- **Public Policy Responsiveness:** ensuring compliance with mandated statutory and regulatory requirements; and

- **Financial Performance:** achieving manageable and stable rate impacts over the course of the planning period.

Hydro One is committed to meeting the RRF outcomes and has integrated them into its investment planning process. As shown through various distribution investment summary documents (see appendices to DSP Section 3.11), each investment is developed with consideration for how it will achieve outcomes in alignment with the RRF framework.

3.1.10 CUSTOMER ENGAGEMENT

As detailed in SPF Section 1.6 and SPF Section 1.7, feedback from customer engagement directly informed and shaped the development of the investment plan. In 2019 and 2020, Hydro One retained Innovative Research Group (IRG) to conduct a multi-phase customer engagement process, the first time that Hydro One has undertaken a multi-phase engagement, to inform and refine the investment plans.

Customer feedback in Phase 1 (September 2019 to February 2020) provided valuable input on customer priorities, including indicative investment envelopes and preferred outcomes, which Hydro One used in developing initial scenarios for the investment plans. Distribution customers prioritized reasonable rates and reliable service. In respect of reliability outcomes, customers generally supported either investing to maintain the current system reliability or improving reliability to reduce outage frequency and duration. A clear majority of distribution customers wanted (i) a more proactive approach to replacing aging distribution infrastructure, (ii) more emphasis on helping those experiencing poor reliability, and (iii) technology investments that reduce costs, improve reliability and help customers manage electricity usage.[11]

[11] Ibid.

The outbreak of the COVID-19 pandemic started shortly after completion of Phase 1. To assess whether the Phase 1 results had changed because of the COVID-19 outbreak, IRG carried out a “pulse check” survey among Hydro One’s residential and small business customers.

The results of this pulse check were in line with the Phase 1 results, indicating that customer needs and preferences had not shifted in any material way and the Phase 1 results remained a valid base and instructive for the investment planning process.

In Phase 2 (August to October, 2020), customers were presented with trade-off options, representing multiple choices Hydro One has within its investment plan, which were informed by Phase 1. For each investment decision, customers were provided the option to choose between a representative “draft plan” (Scenario 2), an accelerated pace plan (Scenario 3), or a slower pace plan (Scenario 1). Each trade-off option reflected a different risk level. For example, Hydro One may be able to defer some investments by delaying the replacement of equipment, but with more risk of failure, power outages and higher costs in the future.

All distribution customers[12] were invited to participate by completing an online workbook covering the draft plans for both the Distribution and the Transmission system. First Nation communities and the Métis Nation of Ontario were engaged through separate online workbooks and in-depth interviews, and municipalities and key stakeholders were invited to provide feedback through one-on-one interviews. Through Phase 2 of customer engagement, over 43,000 customers completed the online workbook. In general, a majority of customers preferred the draft plan (Scenario 2) over accelerated or slower paced options, except for modernization of the distribution system, where a plurality of customers preferred an accelerated plan

[12]Hydro One’s distribution customers fall into three categories: (i) Residential and Small Business (GS<50kW) customers; (ii) Commercial and Industrial customers (<2MW); and (iii) Large Distribution Accounts, or “Key Accounts” (>2MW). Customers directly connected to the transmission system are made up of: (i) Electricity Generators who deliver power to the transmission system; (ii) Distributors who deliver power to direct customers; and (iii) End-users such as mining and industrial enterprises that use the power themselves at transmission level voltage. In addition, both systems serve First Nation and Métis communities in different areas of the province.

(Scenario 3) and replacing power transformers in poor condition where customer support was split between the draft plan (Scenario 2) and the accelerated plan (Scenario 3).

As detailed in SPF Section 1.6, Hydro One refined the distribution capital investment plan based on the results of the customer engagement. This refinement occurred in conjunction with other factors, including the alignment between asset needs and overall costs, resulting in an investment plan that reflects customer needs and preferences as well as other planning factors.

Through this extensive, multi-phase process, Hydro One was able to develop and refine a capital expenditure plan that is aligned with and responsive to customer needs and preferences.

3.1.11 ASSET MANAGEMENT PROCESS

Through its approach to asset management, Hydro One monitors its distribution asset population to determine the optimal manner of intervention. Hydro One tracks and evaluates its system assets, identify and define needs, and determines the appropriate timing for investments and maintenance activities in relation to asset condition and lifecycle management. The above-noted System Renewal investments are primarily underpinned by asset condition data from ongoing asset needs assessment (the AMI 2.0 investment is driven by failure rates and by the age of the assets).

The proposed investments in this DSP do not target all poor condition assets or known risks on the system, and instead address only the ones that present higher risks to ensure system reliability. Residual risk is managed to establish a balanced portfolio to maintain system health and reliability while mitigating rate impact.

Aside from addressing the risks from poor condition assets, significant renewal investments over the DSP period are driven by non-discretionary service obligations related to storm and trouble response ($552M, DSP Section 3.11, D-SR-05) as well as the need to reduce operational, financial and regulatory risks from AMI 1.0 meter failures by deploying AMI 2.0 infrastructure through to 2028 (including $558M in the JRAP period, DSP Section 3.11, D-SR-12). In addition, one of the Company's asset management objectives is to satisfy its regulatory and service obligations as a licensed distributor, including to accommodate the connection of load/generation customers, respond to third party joint use and relocation requests, and ensure adequate distribution capacity to meet growing load demand.

Based on identified asset and system needs, Hydro One develops a suite of candidate investments for further screening and prioritization. In this regard, opportunities to group and bundle related needs, based on logical, functional and geographic groups, are considered where appropriate. The information and data collected through the asset management process establish the requisite fact base to assess the probability and consequence of safety, reliability and environmental risks at the scoring stage of the investment planning process (discussed below).

3.1.12 INVESTMENT PLANNING PROCESS

Through its investment planning process, Hydro One develops a consistent understanding of risks and investment benefits, so as to cost effectively deliver high-value investments to serve its customers. This process allows the effective assessment and prioritization of candidate investments based on the level of risk mitigated relative to the cost required.

As part of the investment planning process, Hydro One planners determine risk probability (based on asset condition, performance and utilization) and risk consequence (based on asset criticality across three fact-driven taxonomies of safety, reliability and environmental risks). Each risk taxonomy features clear definitions and consistent assessment, permitting a proper comparison between candidate investments. Planners quantify the risk mitigated by comparing the expected operational risks of not making the investment versus the residual risks that would remain if the investment is made. As an important basis for prioritization, this risk assessment emphasizes fact-based and quantitative decision-making, relying on historical data to the extent possible and taking into account the efficiency and total benefits of risk mitigated by each candidate investment.

Customer-driven outcomes directly impact this process through the definition of consequence scores and risk taxonomies as well as “flags” that reflect priorities and investment benefits beyond quantified risk mitigation. In alignment with RRF outcomes and corporate priorities, flags are clearly defined to reflect either mandatory obligations (e.g., obligations to regulators, stakeholders or contractual counterparties) or non-mandatory priorities (e.g., First Nations needs, customer preferences, productivity commitments, corrective maintenance/ replacements).

Once candidate investments have been scored and flagged, enterprise-wide calibration sessions occur to ensure comparable and consistent evaluation across investments and lines of business. Based on the risk scores and cost estimates associated with each investment, candidate investments are ranked according to risk mitigation achieved per dollar. As another layer of planning rigor and validation, challenge sessions take place among a broad set of stakeholders to debate the feasibility and merits of investments on the margin and to ensure that valuable investments (from both a risk and non-risk perspective) are included in the plan. The output is an investment portfolio that is subject to enterprise engagement with portfolio owners and the executing lines of business, so as to create a realistic and up-to-date plan (i.e. reflecting the latest cost estimates, schedules and investment scope) and account for operational and execution considerations (e.g., resourcing, material availability and outage feasibility).

3.1.13 ABILITY TO EXECUTE THE PLAN

Following approval of the business plan by the Board of Directors, the work is released to the execution team who takes ownership of delivery of the plan. The plan is reviewed and modified where appropriate throughout the execution phase as new information on asset condition and risks become available.

Hydro One has demonstrated its ability to successfully deliver large capital work plans very close to target at a portfolio level. For the years 2019 and 2020, Hydro One achieved $585.1M (+5%)

and $668.1 (-1%) respectively of in-service additions.[13] This result is the product of a mature capital delivery process with strong oversight and governance and an experienced execution organization that completes the work using both Hydro One's skilled internal workforce and qualified external contractors.

With respect to resourcing, a work-based approach is used, whereby Hydro One sources staff according to work programs rather than planning the work around the internal resources available. To address the fluctuating and seasonal nature of Hydro One Distribution's work program, the Company maintains flexibility by using a variety of labour resources, including regular, hiring hall, temporary, and contract staff. Hydro One Distribution also has the ability to use Hydro One Transmission project crews to support work programs and projects across the province.

Compared to the Transmission work portfolio, the Distribution portfolio is predominantly program-based with smaller scale projects. In addition, Distribution is required to respond to a much higher volume of demand work with short turnaround times. To succeed in this highly dynamic and complex operating environment, Distribution has a nimble and dynamic process for re-prioritizing and transitioning from planned to demand work as required.

Through this process, Hydro One maintains robust oversight over its Distribution work portfolio, with significant improvements made in recent years to drive necessary program and project management and improve forecasting and reporting capabilities. Hydro One closely tracks year-to-date expenditures and accomplishments as well as projected year-end expenditures. Investments are monitored and scrutinized at multiple levels to ensure that material changes to scope, cost or schedule are identified. As changes to investments or other circumstances occur during the year, Hydro One deploys a rigorous redirection process (see SPF Section 1.6) to

[13] Including the General Plant in-service additions allocated to Distribution. See DSP Section 3.9, Attachment 2, Capital Program Performance Report 2019 and 2020.

reprioritize work based on new information and impact on projects' expected value, timing, cost, customer benefits, and other factors.

SECTION 3.2 – DSP – ASSET INFORMATION AND LIFE CYCLE STRATEGIES

3.2.1 INTRODUCTION

This section presents information related to the major distribution station and line components that comprise Hydro One's distribution system (see system description in DSP Section 3.1). Information relating to these distribution components includes a description and purpose of the component; demographic, condition and/or performance information; and lifecycle strategy, including approaches to maintenance and replacement. All information presented is current as of December 31, 2020 unless otherwise noted.

Hydro One operates and maintains power system assets associated with 992 distributing and regulating stations, which are critical to the reliable transformation and delivery of power received from the transmission system to distribution customers across the province. Distribution stations step down voltage from transmission or sub-transmission levels to primary distribution voltage for distribution to commercial, industrial, farm and residential customers. Distribution station components presented in this section include: station transformers (3.2.2.1), station reclosers and breakers (3.2.2.2), station switches and fuses (3.2.2.3), and mobile unit substations (MUS) (3.2.2.4).

Hydro One operates and maintains power system assets associated with over 123,000 circuit kilometres of distribution lines, which are critical to the reliable delivery of power to over 1.4 million distribution customers across the province. Distribution line components presented in this section include poles (3.2.3.1), cross arms (3.2.3.2), conductors (3.2.3.3), and line transformers (3.2.3.4). Rights of ways associated with distribution line facilities are also discussed (3.2.3.5).

Finally, this section also includes information regarding wholesale revenue and retail meters (3.2.4).

ASSET CONDITION

Condition-based renewal is the cornerstone of Hydro One's asset management and investment planning process as discussed in SPF Section 1.7 and DSP Section 3.7. Condition degradation leads to elevated risk of failure. If left unmitigated, such risk can materialize in failures of critical distribution system assets and adverse impacts on system operations or performance. Where the potential failure of poor condition assets may lead to significant reliability, safety and/or environmental impacts, Hydro One must mitigate the risk on a planned basis.

Condition assessments account for a range of considerations, including diagnostic testing results, visual inspections that gauge the deterioration of relevant components, and history of repair that indicates a higher probability of failure. Where condition assessment is not feasible given the nature of a particular asset (e.g. electronic components of meters), assessments are based on factors such as years in service, known performance issues, availability of spares and vendor support, and/or obsolescence.

While expected service life (ESL) is a useful population-level indicator of asset demographics, it is not a driver for replacement. Similarly, as a lagging indicator of asset condition, reliability performance cannot replace condition as the primary basis for renewal investments. The condition of the assets across Distribution lines and stations determines the replacement. Leaving poor condition assets unaddressed will lead to elevated risks for reliability (e.g. failed components resulting in unplanned customer outages), safety (e.g. submarine cables with damaged neutrals that continue to deteriorate can become a public safety hazard), and the environment (e.g. transformer oil leaks). In addition, unplanned equipment outages may impact Hydro One's ability to proceed with planned outages, potentially resulting in the cancellation or rescheduling of required maintenance work. This can delay preventative and corrective maintenance work and increase the risk of equipment failure that further compounds the aforementioned risks.

ASSET DEMOGRAPHICS

Hydro One operates and maintains power system assets associated with 992 distributing and regulating stations, and over 123,000 circuit kilometres of distribution lines which are critical to the reliable transformation and delivery of power received from the transmission system to distribution customers across the province. Distribution stations step down voltage from transmission or sub-transmission levels to primary distribution voltage for distribution to commercial, industrial, farm and residential customers. Regulating stations are a special type of station that maintains voltage within prescribed limits in response to load variations and resulting voltage fluctuations.

ESL enables a view of asset demographics based on the average number of years that an asset is expected to operate under normal system conditions and is determined with reference to manufacturer guidelines and Hydro One's historical asset retirement data. The longer an asset has been in service, the more cumulative wear and tear accrues from its ongoing utilization and environmental exposure, and thus these assets tend to exhibit greater condition deterioration compared to younger assets.

ESL does not drive replacement decisions. However, it can provide useful information at the fleet level for gauging overall asset demographics. ESL sheds light on the directional magnitude of possible replacement needs (but never to underpin the actual replacements) over the longer term.

In limited cases where the nature of the particular assets (e.g. electronic metering devices) means that actual condition cannot be tested, ESL is an important input for the appropriate lifecycle management strategy in alignment with industry practices.

The current average age of Hydro One's distribution station transformer fleet is 39 years. Currently, 33% of the fleet is beyond their ESL of 50 years, and an additional 17% (if no capital replacements are undertaken) will reach or exceed their ESL by 2027, which would bring the total to 50%.

The average age of the MUS transformers is 34 years and currently 46% of the MUS transformers are beyond their ESL of 40 years. The average age of the MUS trailers is 17 years, and currently 23% of the MUS trailers are beyond their ESL of 25 years. It is important to note that age does not drive the replacement of MUSs.

The average age of poles is 40.2 years. There are currently 378,000 poles (23%) that are 60 years of age or older. Over the 2023 to 2027 planning period, the number of poles 60 years or older would increase to 500,000 poles (31%) in the absence of pole replacements.

Details regarding condition and age for other Distribution Stations and Distribution Lines assets are provided in the sections that follow.

ASSET PERFORMANCE

Asset performance can be measured by equipment-related failures or outages. Hydro One's distribution system is typically planned based on a radial supply, as this is the most cost-effective means of distributing electricity to end-use customers. A radial design, however, does not have an alternate source of power in the event of an outage. As a result, equipment outages will often lead to customer outages until the issue can be resolved or a temporary solution can be put in place (e.g. until an MUS is installed to restore load where a transformer failure has caused an outage).

Reliability performance related to asset failure is a lagging indicator of asset condition and the impact of renewal investments (or absence thereof), and do not drive replacement decisions. Major distribution assets are renewed based on their condition assessment. Lagging performance trends cannot reasonably provide a planning proxy for condition-based assessments.

Assets in poor condition can lead to performance issues, but are not the only cause of outages. At the individual asset level, forced outages can be caused by a number of issues, including factors like animal contact, weather, and vegetation contact, and therefore may not always be attributable to or directly indicative of asset condition. As such, making investment decisions based solely on such performance statistics (as opposed to a robust investment approach driven by actual condition) may not address the underlying condition issues impacting performance and posing safety, reliability or environmental risks.

For these reasons, Hydro One does not generally rely on performance trends to plan future investments, nor can Hydro One afford to allow failures to proliferate and customer reliability to worsen over time before addressing poor condition assets through suddenly escalated capital investments.

However, Hydro One does closely monitor equipment performance to ensure that customers receive the appropriate level of service and that performance issues requiring urgent resolution or planned corrective actions are effectively identified and addressed.

ASSET LIFECYCLE

Hydro One's approach to lifecycle management maximizes benefits to Hydro One and its customers during the asset's service life, while balancing asset performance, condition, and risks to Hydro One's business objectives, as discussed further in DSP Section 3.1.

Hydro One manages distribution assets through planned and demand maintenance programs and capital investments. Hydro One's inspection practices and frequencies for distribution assets are established to ensure their safe and reliable operations and to satisfy the Minimum Inspection Requirements under the Distribution System Code.

Through inspections, the condition of distribution assets is monitored. Deficiencies that are identified are prioritized and addressed through corrective maintenance or capital replacement investments. The frequencies and prioritization for removing station assets from service for maintenance are based on input such as asset condition data (obtained through inspections and diagnostic testing), maintenance records, manufacturer recommendations, replacement plans, bundling opportunities, and funding constraints. For identified capital replacement candidates, the Risk Spend Efficiency (RSE) approach (see DSP Section 3.7) drives the replacement prioritization.

3.2.2 ASSET COMPONENT INFORMATION – DISTRIBUTION STATIONS

This section discusses the main assets found in distribution stations including:

- Station transformers and regulators;
- Reclosers and breakers;
- Switches and fuses;
- Mobile Unit Substations (MUS); and
- Other station assets.

3.2.2.1 STATION TRANSFORMERS

ASSET DESCRIPTION / PURPOSE

As the most costly component of Hydro One's distribution station asset base, station transformers (see example depicted in Figure 1 below) convert a high level voltage (typically 115, 44 or 27.6 kV) to a lower distribution voltage (typically 27.6, 25, 13.8, 12.47, 8.32 or 4.16 kV). This asset class also includes regulating transformers, which provide voltage control on the distribution system.

Figure 1: Station Transformer

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

Hydro One owns and operates 1,197 distribution station transformers, as categorized in Table 11 below by primary voltage level.

Table 1 - Transformer Count by Voltage Level

Primary Voltage Level	Number of Transformers
230 kV	1
115 kV	140
44 kV	780
27.6 kV	234
< 27.6 kV	42

The current average age of Hydro One's distribution transformer fleet is 39 years (Figure 2). Currently, 33% of the fleet are beyond their ESL of 50 years, and an additional 17% (if no capital replacements are undertaken) will reach or exceed their ESL by 2027, which would bring the total to 50%.

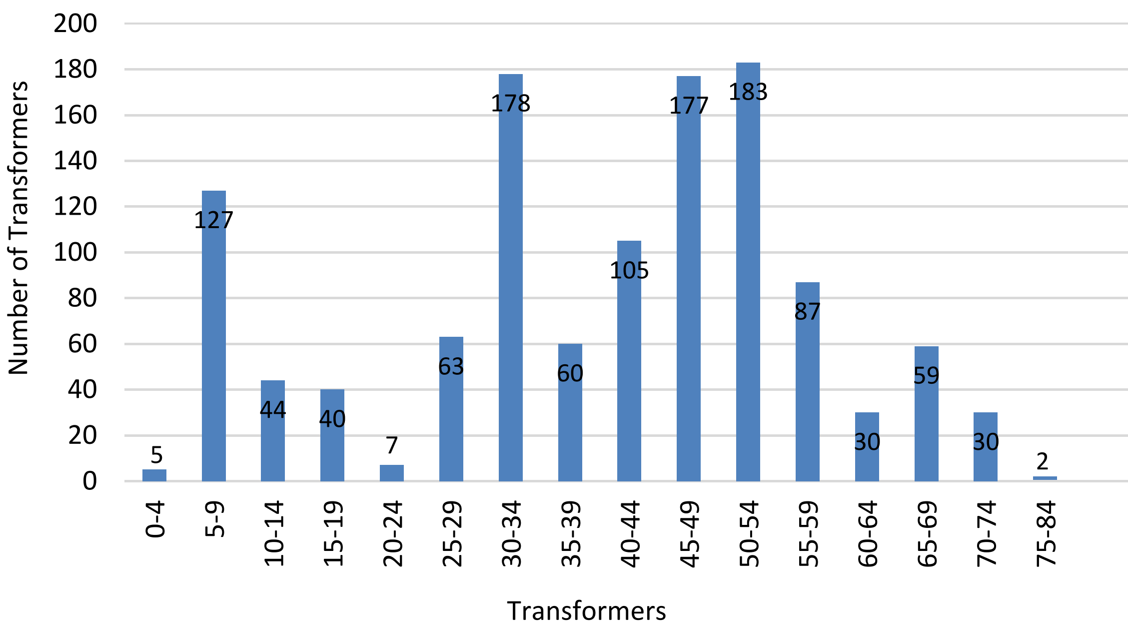


Figure 2: Demographics of the Distribution Station Transformers

ASSET CONDITION

Approximately 20% (237) of Hydro One's distribution station transformers fall into the poor condition category (Figure 3). These units are at a higher risk of failure compared to the overall transformer population and are considered for replacement or corrective repair in order to correct significant deterioration or deficiencies before failures occur and impact service to distribution customers.

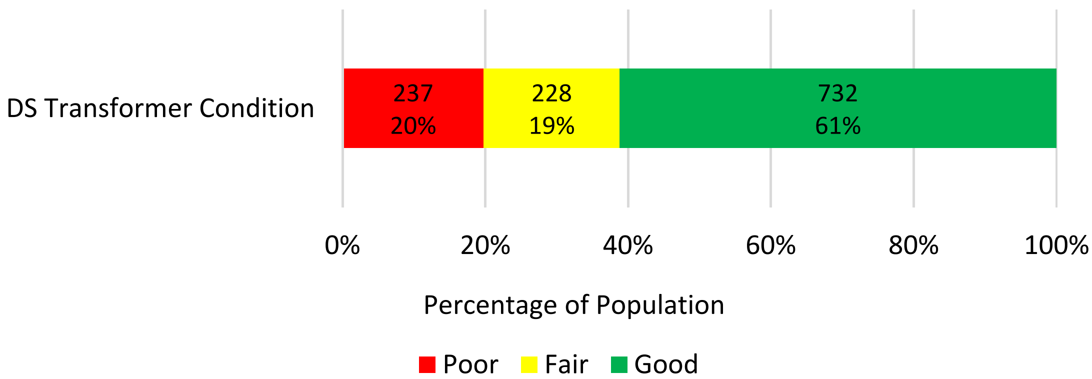


Figure 3: DS Transformer Condition

Many factors lead to the degradation of a transformer's internal components over time, including: transformer loading, switching, lightning surges, moisture contamination, and paper insulation degradation. The internal components degrade over time and the resulting asset condition is one of the leading predictive indicators of transformer failure.

Hydro One assesses a distribution transformer's condition based on transformer oil test results (obtained via industry standard diagnostic testing), visual inspections, thermographic inspections, internal inspections and diagnostic testing. Annual oil sample test results are obtained for all transformer main tanks and under-load tap-changer compartments. Visual inspections identify aspects of transformer condition such as oil leaks and under-load tap-changer operation. Thermographic inspections identify transformer components that are overheating. Internal inspections and diagnostic testing can identify the source of the poor transformer condition that was identified through oil sampling.

Testing and inspection results indicating poor condition identify transformers that are expected to fail. Corrective repair or planned replacement of these transformers before they fail is crucial to avoid reactive measures upon failure and associated lengthy customer interruptions (see "Asset Lifecycle" section below regarding repair and replace decisions).

ASSET PERFORMANCE

Station transformer failures are highly impactful. Hydro One's distribution stations typically do not have on-site spare transformers that can be switched into service in the event of a failure, and load cannot typically be transferred among rural stations, which are primarily fed from a radial system. In these instances, when a station transformer fails or is failing, service restoration requires that an MUS be transported to the station and installed (assuming the necessary MUS connection structures already exist at the station) to provide a temporary supply during the outage. An MUS takes 6.6 hours on average to install before power can be temporarily restored to customers. In severe cases, these outages can take up to 21 hours depending on the distance from the station to the nearest available MUS, and the availability and condition of the MUS structures that are required for connecting the MUS at the station.

Hydro One categorizes distribution station transformer failures into the following two categories:

- *Class 1 Failures* – Station transformer failures which resulted in customer interruptions. Customers are without power until an MUS is installed to restore load. On average these interruptions last 6.6 hours. Historically, approximately 80% of Class 1 distribution station transformer failures have required replacement, and 20% were repairable.

- *Class 2 Failures* – Station transformer failures avoided through oil sampling which indicates that failure is imminent and triggers timely corrective or capital intervention. These failures do not result in a customer interruption. Upon observation of imminent failure, the relevant transformers are taken out-of-service and an MUS is installed at the station (where possible) to avoid customer interruption. Historically, approximately 40% of Class 2 transformer failures have required replacement and 60% were repairable.

The number of transformer failures (Class 1) and number of imminent failures avoided by removal of transformers from service (Class 2) are shown in Figure 4.

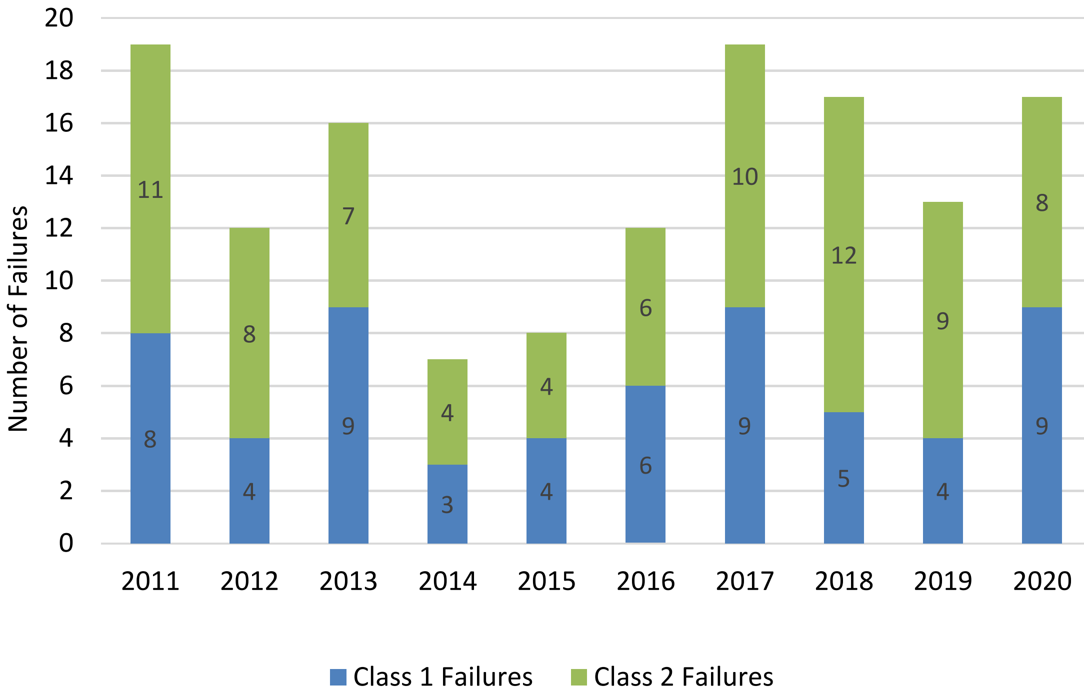


Figure 4: Failures of Station Transformers

From 2011 to 2020, the total Class 1 and Class 2 failures have ranged from 7 to 19 each year; with 2020 experiencing 17 failures. Through annual oil sampling and close monitoring of transformers with poor condition test results, Hydro One is able to avoid a number of major failures per year which would have otherwise resulted in lengthy customer interruptions. With planned replacements, Hydro One expects the number of Class 1 and Class 2 failures over the 2023 to 2027 planning period to be consistent with historical years. In the absence of planned replacements, the number of failures would significantly increase, and Hydro One would not have enough MUS to temporarily bypass the failed transformers and supply customers. Once the MUS fleet has been depleted, subsequent failures would result in customer interruptions, which would take more than 24 hours to restore load.

Figure 5 below represents the yearly contribution of station transformer Class 1 failures to System Average Interruption Duration Index (SAIDI). The annual average transformer SAIDI contribution resulting from Class 1 failures has been 0.021 hours (or 1 minute, 16 seconds).

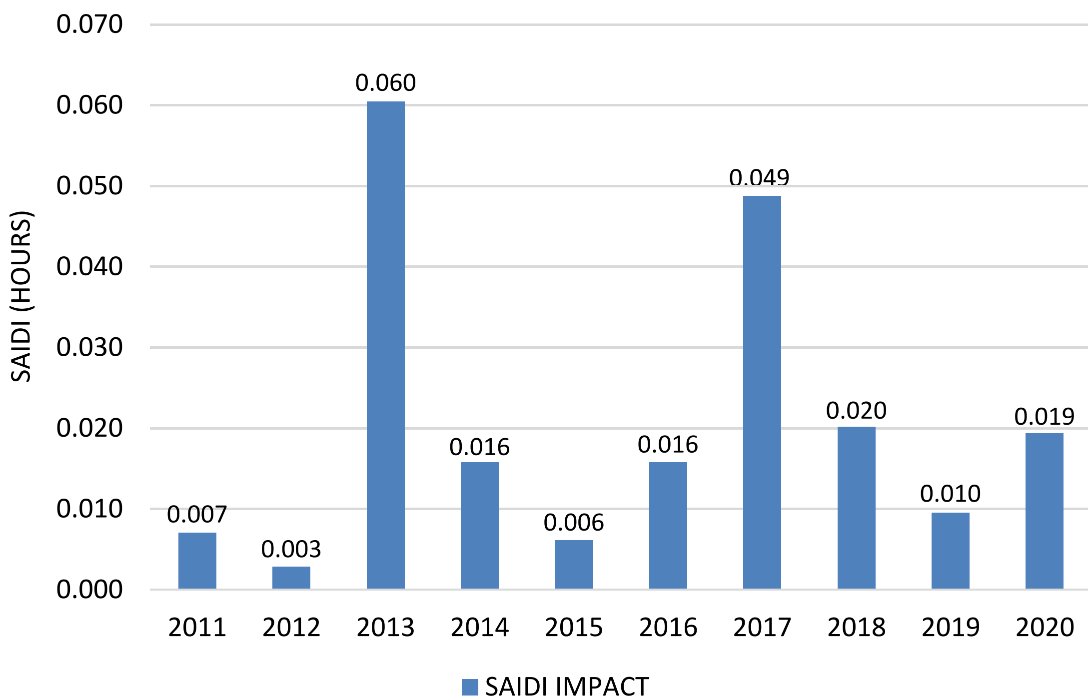


Figure 5: DS Transformer SAIDI

Currently 33% of the transformer population are beyond their 50 year ESL. From 2021 to 2027, an additional 17% of the transformer population will reach their ESL if no planned replacements are undertaken. It is expected that transformer condition during this period will deteriorate in the absence of planned replacements. In order to manage the condition of the transformer population and failure risk, planned transformer replacements based on current known condition are required. If poor-condition transformers are not replaced, transformer failures are expected to increase because poor-condition transformers are subject to internal overheating, internal burning, and degradation of paper insulation around windings or water in the insulating oil. Overheating or burning can cause a transformer to fail by melting of current carrying components. Degradation of paper insulation or water in insulating oil can lead to a phase-to-phase fault or phase-to-ground fault within the transformer.

LIFECYCLE STRATEGY

Hydro One aims to mitigate the risk of distribution station failures through predictive testing, condition based corrective maintenance or planned replacement of transformers to avoid asset failure and lengthy customer interruptions.

Transformers identified as in fair condition are typically addressed through corrective maintenance activities, and monitoring of the transformer condition to help prevent further degradation.

Transformers identified as in poor condition are considered for replacement or corrective maintenance. The factors that inform whether a poor-condition transformer is proposed for replacement or corrective maintenance include the age of the unit and the extent of corrective maintenance required.

INSPECTION & MAINTENANCE PRACTICES

Preventive Maintenance

To effectively maintain its distribution transformer population, Hydro One utilizes seven types of maintenance activities (each with associated tasks and frequency of completion). Transformer deficiencies observed through the following testing and inspection methods can lead to either corrective maintenance activities or transformer replacement depending on the findings and condition:

- *Station Visual Inspection* – Station transformers and regulators are visually inspected on a six month cycle for rural stations and monthly for urban stations.
- *Thermographic Inspection* – Each station undergoes a thermographic inspection of all power equipment every two years to identify hot spots in station electrical components.

- *General Oil Test* – Annually, an oil sample is taken from the transformer main tank and sent to a third party lab for analysis to obtain industry-standard diagnostic test results including Dissolved Gas Analysis, Moisture Content and Furan Analysis.
- *Transformer Diagnostic Test* – Following an unsatisfactory oil sample result, the main tank of the transformer may receive diagnostic testing and internal inspection. This maintenance activity includes but is not limited to inspection of current carrying parts, insulation resistance tests, turns ratio and phase angle tests, core loss test, winding resistance test, repair of minor or moderate oil leaks, and oil level check and top-up.
- *Under-Load Tap-Changer Oil Analysis* – Annually, an oil sample is taken from tap-changer oil-filled compartments and sent to a third party lab for analysis to obtain industry-standard diagnostic test results including Dissolved Gas Analysis and Moisture Content.
- *Tap-Changer Selective Intrusive Inspection* – Internal inspection and maintenance of under-load tap-changers with mechanical moving parts are performed when unsatisfactory tap changer oil analysis results or unsatisfactory performance are identified. This maintenance activity includes: filtration of insulating oil, flush and cleaning of oil compartments, visual check for oil leaks and contact wear, inspection of current carrying parts, checks of insulation condition, collector ring, drive chains, pushrod, reversing switch, oil compartment door gaskets, exercise isolation and grounding switch, and function test of operating limit switches, gauges and indicators.
- *Power Factor Test* – 115 kV and 230 kV distribution station transformers receive a power factor test to verify the integrity of the transformer insulation material and ensure they are functioning correctly. This test is performed when the transformers are removed from service for diagnostic testing or selective intrusive maintenance.

Corrective Maintenance

Based on the findings of cyclical inspections, transformer maintenance is prioritized based on observed condition or other issues and includes the following three categories:

- Transformer Condition Based Maintenance (CBM) following high risk oil sample results for transformer main tanks or tap-changers;

- Maintenance on leaking transformers to mitigate the leaks; and
- Maintenance on transformers with unsatisfactory polychlorinated biphenyl (PCB) content[1] to reduce PCB content in oil filled compartments to meet Environment Canada requirements.

REPLACEMENT & REFURBISHMENT

Fair condition transformers are candidates for corrective repair or monitoring. Fair condition transformers experience elevated dissolved gas analysis results, moisture content in oil, insulation paper degradation and oil leaks, just as poor condition transformers but not as severe.

Once it is known that a transformer is in poor condition, the transformer is considered for repair or replacement. Younger transformers in poor condition are typically candidates for corrective repair. Performing corrective repairs on younger transformers normally allows them to reach their 50 year ESL.

Poor condition transformers approaching or beyond their 50 year ESL tend to be candidates for replacement as opposed to corrective repair. This is because correctively repairing an older transformer may only slightly extend its service life, which would not be economical as more components are expected to fail and need to be further addressed. The repair versus replacement decision is driven by factors such as condition, age, and the cost of corrective work.

For identified transformer replacement candidates, the RSE approach (see DSP Section 3.7) drives the replacement prioritization. Transformers in poor condition that have a lower priority may be considered for repair as opposed to replacement, if possible and economical. Factors that feed into the RSE prioritization include transformer condition, downstream customer

[1] PCBs were used as an additive to transformer oil up until the late 1970's.

counts, estimated outage duration if the transformer fails, and environmental impact (e.g. major oil leaks that are costly to repair).

Poor condition transformers that have been prioritized for capital intervention based on RSE are addressed through the following alternatives:

- Planned transformer replacements,
- Station rebuilds,
- Station replacements with non-fenced pad-mount solutions (load permitting), or
- Voltage conversion projects involving the elimination of the station and the transformer.

The effective long-term management of poor condition transformers requires sustained capital investment to replace transformers on a planned basis and address poor condition transformers before their elevated failure risk materializes. A sustained program targeting a high number of poor condition transformers is required to maintain the number of transformer failures at a manageable level.

3.2.2.2 STATION RECLOSERS & BREAKERS

ASSET DESCRIPTION / PURPOSE

Reclosers

Hydro One currently manages 2,288 three-phase equivalent distribution station reclosers (see example depicted in Figure 6 below). Reclosers are used to remove assets from service under fault conditions. Reclosers can rapidly open and reclose in an attempt to clear system faults, restoring service to customers when faults are temporary or transient in nature.

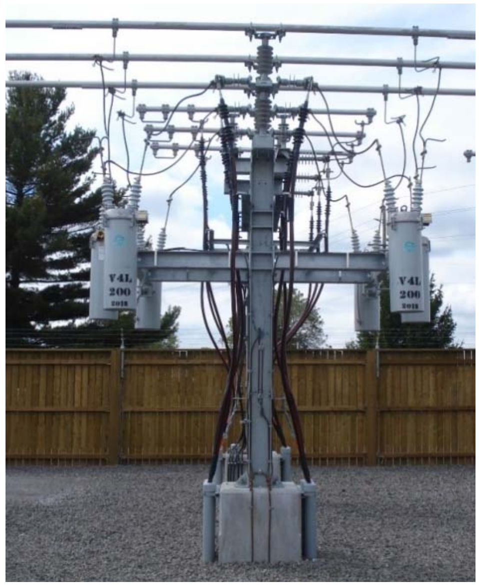


Figure 6: Picture of Station Reclosers

Breakers

Hydro One currently manages 152 distribution station circuit breakers (see example depicted in Figure 7 below). Like reclosers, breakers are used to remove assets from service under fault conditions. However, breakers cannot rapidly open and reclose like a recloser to clear system faults.

Figure 7: Picture of a Metalclad Breaker

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

ASSET DEMOGRAPHICS

Reclosers

The reclosers within Hydro One distribution stations have either oil or vacuum interrupters and are either hydraulic or electronic controlled. The number of devices for each type is shown in Table 2.

Table 2 - Recloser Count by Type

Type	Number of Feeders
Oil interrupter & hydraulic controlled	1,217
Oil interrupter & electronic controlled	60
Vacuum interrupter & hydraulic controlled	618
Vacuum interrupter & electronic controlled	393

Oil reclosers use oil to act as an arc extinguishing agent during interruption and to insulate recloser contacts from each other after the arc has been extinguished. Hydro One no longer purchases oil interrupter reclosers because they require more frequent maintenance compared to vacuum interrupter reclosers.

Vacuum reclosers have interrupters that use magnetic fields to aid in extinguishing the arc. The arc is moved around the surfaces of the recloser contacts, which minimizes contact erosion and formation of hot spots. Vacuum interrupter technology requires less maintenance and has higher reliability over other arc quenching media such as oil.

All reclosers Hydro One purchases today are vacuum interrupter reclosers and are either hydraulic or electronic controlled, depending on system needs. Hydraulic reclosers use hydraulic control to sense overcurrent and provide timed tripping, reclosing functions and lockout.Electronic reclosers are controlled by a programmable digital protective relay, also known as an IED, and provide additional functionality such as remote operation.

Breakers

Hydro One has three types of breakers on its distribution system. The number of devices for each type is shown in Table 3.

Table 3 - Breakers by Type

Type	Number of Breakers
Metalclad	149
SF6	2
Oil	1

Most metal clad breakers on the Hydro One distribution system are obsolete and replacement parts may not be available. These breakers are no longer supported by the manufacturer. As such, if one breaker in a bank of metalclad breakers fails and is not repairable, the entire bank of metalclad breakers may need to be replaced. In addition, some of the metalclad breakers were designed to be installed in small buildings, which do not meet Hydro One’s current clearance requirements. Hydro One mitigates this risk with safe work practices, removing the breaker from service before the execution of work.

ASSET CONDITION

Reclosers

The condition of reclosers is primarily driven by the condition of the recloser contacts which provide for arc extinction. Contact wear is driven by the number of operations as well as the interrupter type. Recloser contacts in oil interrupters wear nearly four times as quickly as contacts in vacuum interrupters. Defects such as hot spots identified through thermographic inspections, damaged bushings, damaged connectors, rusted tanks or oil leaks identified through visual inspections also factor into recloser condition. Worn contacts and defects observed through thermographic inspections and visual inspections can all lead to recloser failure if not addressed. Figure 8 summarizes the condition of the station recloser population.

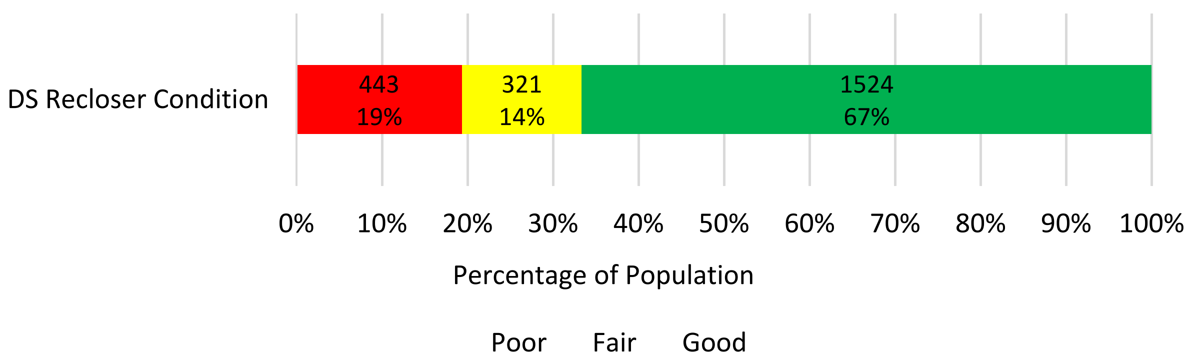


Figure 8: **DS Recloser Condition**

Breakers

The condition of station breakers is primarily driven by deficiencies that can affect their ability to open when required to clear system faults, or impact their ability to close when required to restore power. Breakers have many electromechanical components which must be regularly inspected and maintained to ensure the correct operation of the breaker. Breaker operating mechanisms can become damaged if they are not kept lubricated. Breaker contactors will wear based on the number of operations and the amount of fault current interrupted. Coils and contactors must be regularly inspected and lubricated to monitor wear and ensure they are functioning properly. The wear of other breaker components such as motor commutators and brushes, relays, auxiliary switches must be inspected and monitored. Figure 9 summarizes the condition of the station breaker population.

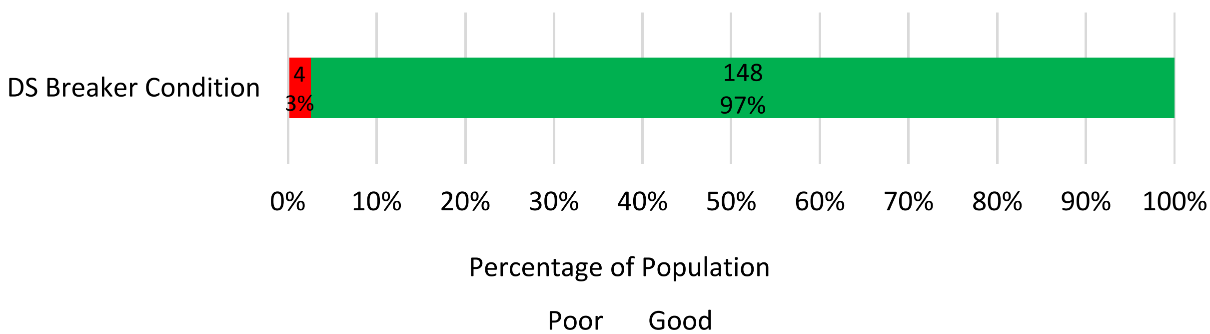


Figure 9: DS Breaker Condition

ASSET PERFORMANCE

Reclosers and breakers must be able to open or close when required to clear transient line faults and restore load. They also must be able to carry the system current without interrupting load during normal system operation. For reclosers and breakers, the following are common failure modes which Hydro One tracks annually:

- Failure to close or reclose
- Failure to interrupt system faults
- Failure to carry rated load

Figure 10 below represents the total annual number of DS recloser failures recorded each year from 2011 to 2020 for the three failure types listed above. Overall there has been an increasing trend in recloser failures over this period.

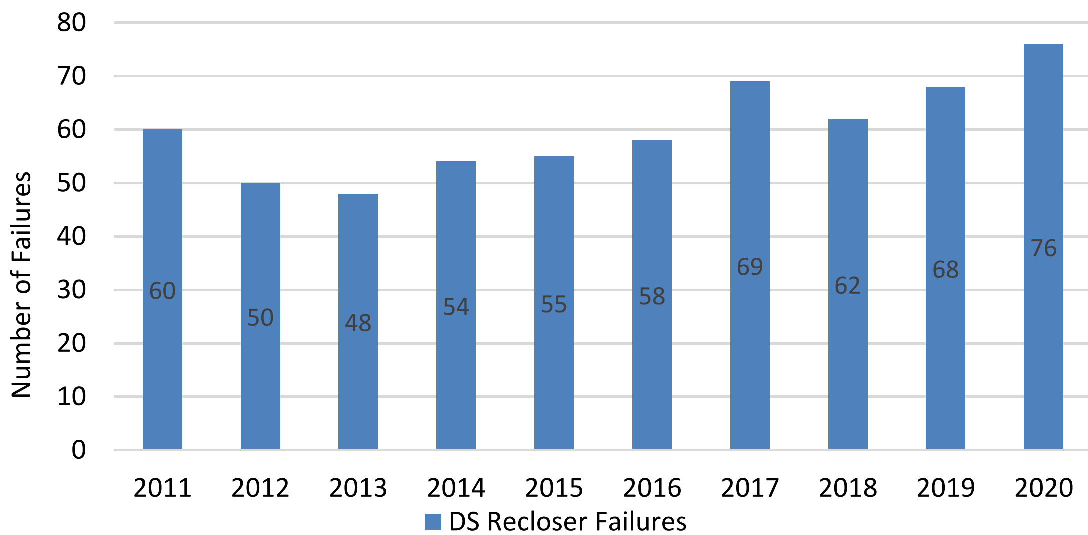


Figure 10: DS Recloser Failures

Figure 11 below represents the annual number of DS breaker failures recorded each year from 2011 to 2020. The number of failures fluctuates each year over this period.

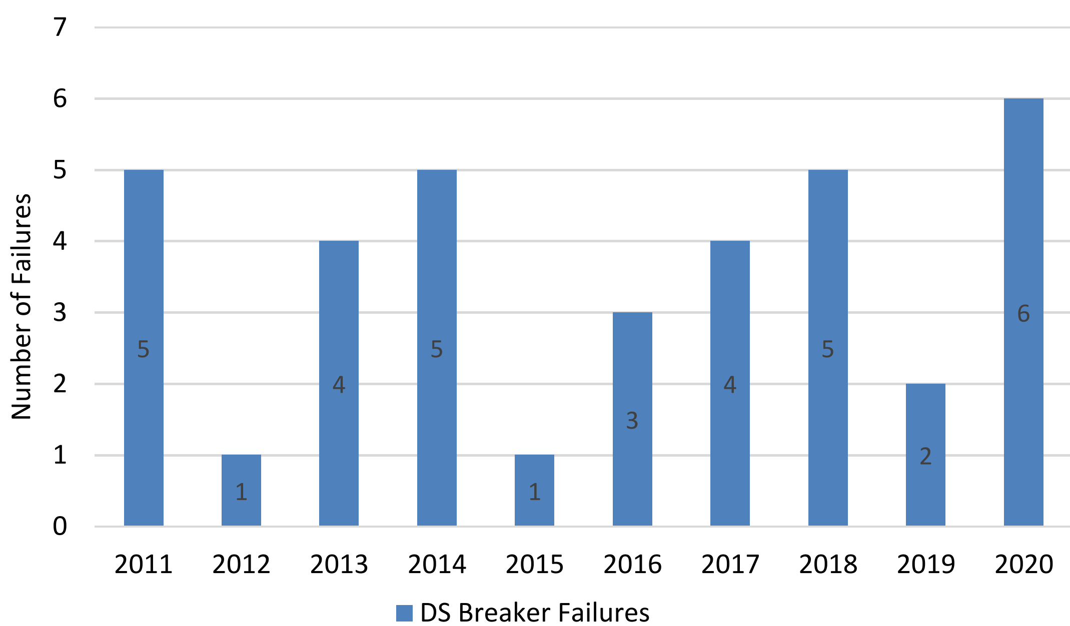


Figure 11: DS Breaker Failures

LIFECYCLE STRATEGY

INSPECTION & MAINTENANCE PRACTICES

Reclosers

Consistent with the recommendations of recloser manufacturers, a primary factor that drives Hydro One's maintenance of these assets is the number of operations that they undergo (in addition to identified visual defects and failure to operate when required).

Distribution stations are inspected in the spring and fall, at which time the station reclosers are visually inspected for any visible defects. The recloser counter operations are checked and recorded to ensure they have not exceeded the manufacturer recommended number of operations since they were last inspected. Stations also receive infrared thermography scan every two years to identify any overheating power equipment (including reclosers), which may indicate a high probability of failure. Reclosers found to be overheating are removed for assessment, and are replaced with a spare from inventory.

Vacuum hydraulic reclosers are expected to endure approximately four times as many operations as oil hydraulic reclosers. Therefore oil hydraulic reclosers require four times the maintenance compared to vacuum hydraulic reclosers. Vacuum electronic reclosers require the least amount of maintenance compared to oil hydraulic and vacuum hydraulic reclosers. Each type of reclosers is further discussed below.

When oil interrupter hydraulic controlled reclosers require maintenance, most model types are replaced with refurbished recloser models of the same type that are stored in inventory. They are maintained (i.e. removed for refurbishment) based on visual inspection results and when the manufacturer recommended counter operations have been reached. Model Type "L" reclosers which make up 74% of the oil interrupter hydraulic recloser population are the only exception, and are upgraded to vacuum interrupter hydraulic reclosers when they require maintenance.

Hydro One's fleet of oil interrupter electronic controlled reclosers receive maintenance based on visual inspection results and when manufacturer recommended counter operations have been reached. These reclosers are older technology and Hydro One is no longer installing them in the system. They have not been posing reliability issues, and therefore Hydro One is not proactively replacing them. However, they are bundled for replacement under stations refurbishment projects where appropriate.

Vacuum interrupter hydraulic controlled reclosers receive maintenance based on visual inspection results and when manufacturer recommended counter operations have been reached. Hydro One is expanding this recloser population by replacing Model Type “L” reclosers with these vacuum reclosers. Vacuum interrupter hydraulic controlled reclosers are the preferred choice for most station capital projects when remote tripping capability and short circuit interruption capability above 6 kilo-amps are not required.

Vacuum interrupter electronic controlled reclosers are visually inspected for deficiencies and controller batteries are replaced on a time cycle. These reclosers are installed under capital projects when remote tripping capability or short circuit interruption capability above 6 kilo-amps is required.

Reclosers are also replaced with higher rated reclosers when fault levels in the system have exceeded the interruption capabilities of the recloser.

Breakers

Hydro One’s strategy for the station breaker population is to continue to maintain the fleet (through preventative maintenance every six years) and continue to keep them in-service until they are replaced or removed through a capital project. The breakers are maintained on a time-cycle in order to inspect, lubricate, test operate or replace the electrical and mechanical components as needed to ensure reliable operation.

To monitor their condition and perform maintenance, breakers must be removed from service and inspected. When these breakers are removed from service for maintenance, they undergo:

- *Diagnostic Test* – The breaker is function tested, manually operated, and undergoes cleaning and lubrication of operating mechanisms; and
- *Selective Intrusive (SI) Inspection* – Inspection of all internal components, insulation condition, contacts and rack-in mechanisms where applicable.

REPLACEMENT & REFURBISHMENT

Reclosers

With the exception of Cooper Model Type “L” oil hydraulic reclosers (which Hydro One is replacing with vacuum hydraulic reclosers when counter operations are reached), all other reclosers receive maintenance based on their condition, performance and when counter readings have exceeded the manufacturer recommended number of operations.

Hydraulic reclosers are physically removed from the station and sent to a maintenance shop. At this time, recloser contacts, oil and other components are replaced based on their condition. The removed hydraulic reclosers are replaced like-for-like with already overhauled reclosers.

For oil interrupter electronic controlled reclosers, when counter readings are exceeded, they are removed from service and maintained at the station. Worn components are replaced and the reclosers are test operated before being returned to service.

Vacuum interrupter electronic controlled reclosers are inspected for visual defects however are considered to be maintenance free. Electronic recloser controllers have back-up batteries which require regular battery replacement. These batteries are scheduled for replacement every five years as recommended by manufacturers.

Replacement – Oil Interrupter Hydraulic Reclosers

In distribution stations, 1,217 feeders are equipped with oil interrupter hydraulic controlled reclosers. Of these, approximately 900 or approximately 74% are Cooper Type L, which require maintenance every 64 operations. The strategy for these reclosers is to replace them with vacuum interrupter hydraulic controlled reclosers as opposed to maintaining them every 64 operations. The lifecycle cost of maintaining new vacuum hydraulic reclosers is much lower in comparison to the lifecycle cost for maintaining Type L reclosers.

Vacuum hydraulic controlled reclosers is the preferred choice over more advanced vacuum electronic reclosers because the cost of vacuum hydraulic reclosers is significantly less. To minimize capital expenditure, vacuum electronic recloses are only utilized if the higher short circuit rating of vacuum electronic reclosers is required to protect the feeder.

Replacement – Vacuum Interrupter Hydraulic Reclosers

Hydro One's plans are to replace oil interrupter hydraulic reclosers with vacuum interrupter hydraulic reclosers which have a lower lifecycle cost. Vacuum interrupter hydraulic reclosers will only be replaced if they fail, or if they must be upgraded to vacuum electronic reclosers to handle higher system short circuit levels.

Replacement – Electronic Reclosers

If the short circuit levels on a feeder are beyond the interruption rating of the installed reclosers, they are upgraded to vacuum electronic as needed to satisfy system fault levels. Otherwise, if the feeder can be safely protected by a vacuum hydraulic recloser, then a vacuum hydraulic recloser is the preferred, less costly option.

When a distribution station undergoes refurbishment, obsolete electronic reclosers will be replaced with vacuum hydraulic reclosers or vacuum electronic reclosers, depending on system needs and potential benefits.

Refurbishment – Breakers

When breakers are removed from service for inspection and maintenance, any defects identified will be addressed prior to returning the breakers to service. If station breakers fail to operate, they will be repaired as long as replacement parts can be obtained.

Replacement – Breakers & Reclosers

During planned station refurbishment or transformer replacement projects, breakers which are obsolete or non-arc resistant will be considered for replacement with vacuum interrupter electronically controlled reclosers. Hydraulic reclosers – while less expensive – are not suitable replacement candidates because they normally cannot interrupt the higher short circuit levels present at these stations. Reclosers offer improved reliability compared to breakers because reclosers can often clear faults by rapid open and close sequences prior to locking out.

Station refurbishment investments are primarily driven by high risk transformers in need of replacement. Hydro One does not have a proactive strategy to replace breakers, other than those bundled with transformer replacements under station refurbishment investments.

3.2.2.3 STATION SWITCHES & FUSES

ASSET DESCRIPTION / PURPOSE

Station switches enable the isolation of equipment such as transformers, breakers or reclosers, including for the purpose of carrying out maintenance work. Station fuses provide a means to protect transformers in stations when a fault occurs and to by-pass station reclosers (although not all distribution station reclosers are equipped with by-pass fuses). Distribution stations which do not have feeder breakers or reclosers are equipped with fuses to provide a means of protection for the feeder.

Figure 12: Picture of Station Switch and Fuse Combination

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

Hydro One currently manages 2,535 three-phase switches and 1,801 three-phase fuses installed at distribution stations. The number of switches and fuses are shown in Table 4 by primary voltage level:

Table 4 - Switches and Fuses by Voltage

Primary Voltage Level	Number of Switches	Number of Fuses
230 kV	2	0
115 kV	153	92
44 kV	865	729
27.6 kV	506	214
< 27.6 kV	1,009	766

Asset Condition

The condition of switch and fuse assets is determined during regular station maintenance program activities. A visual inspection of switch and fuse assets is completed twice a year to note any defects. Defects are also observed during planned station outages for transformer or breaker maintenance work. During these outages, switches are manually test operated and fuses undergo an airflow test.

Some of the main failure modes of switches include seized bearings, misalignment of the blade and jaw and failure of porcelain insulators. These failure modes can render the switches inoperable and can leave the switches stuck in an open or closed position. This can lead to unplanned interruptions or prolonged interruptions to repair the switches and enable the system to be returned to normal operation.

The most common defects observed for fuses include peeling of the outer coating, failed airflow testing, water ingress, broken fuse holders or broken support insulators. Figures 13 and 14 summarize the condition of the station switches and fuses.

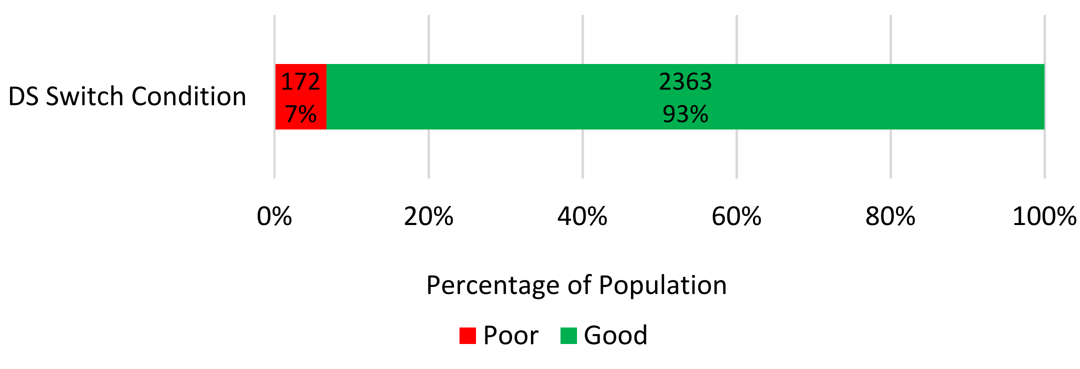


Figure 13: DS Switch Condition

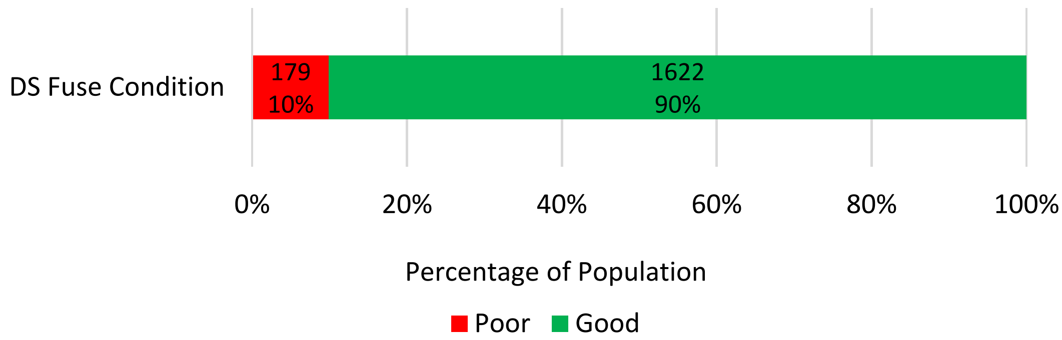


Figure 14: DS Fuse Condition

ASSET PERFORMANCE

Switches are required to isolate station transformers for maintenance work or replacement. If they are unable to close, planned equipment outages may be delayed. The performance of switches is defined by their ability to open when required to isolate equipment, or close when equipment must be returned to service. The following are common failure modes for switches which Hydro One tracks annually:

- Failure to open/close
- Failure to align/centre in jaw
- Failure of load interrupter
- Insulator failure

Figure 15 below represents the annual number of DS switch failures recorded each year from 2011 to 2020.

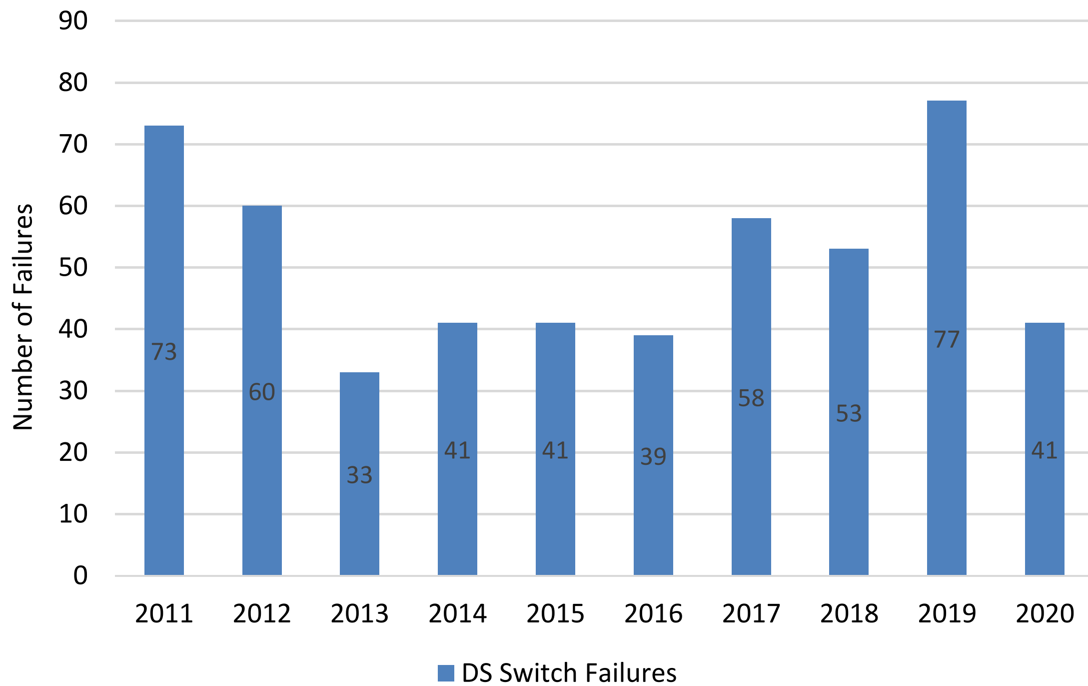


Figure 15: DS Switch Failures

Hydro One does not track performance for station fuses. Station fuses which blow (by design) in order to interrupt system fault currents are replaced with spare fuses once the source of the fault has been cleared.

LIFECYCLE STRATEGY

Inspection & Maintenance Practices

Hydro One visually inspects switches during routine station inspections, and manually test operates them during planned station outages for transformer or breaker maintenance work. Normally defects are discovered when the switch must be operated. Deficiencies that have been identified are normally addressed during planned station outages for transformer or breaker maintenance. Station switches that have been found to be defective and cannot be repaired are planned for replacement.

Hydro One visually inspects fuses during routine station inspections, and performs an airflow test on them during planned station outages for transformer or breaker maintenance work. Fuses that have been found to be defective through visual inspection or airflow test are replaced during planned station outages for transformer or breaker maintenance.

REPLACEMENT & REFURBISHMENT

Replacement

Station switches that have been found to be defective and cannot be repaired are planned for replacement. Normally these defects are discovered when the switch must be operated.

Station fuses that are found to be defective upon inspection or through testing are replaced with new fuses. Transformer or recloser replacements may also trigger the need to replace fuses with those of different continuous current rating and interrupting speed in order to allow for proper protection coordination.

3.2.2.4 MOBILE UNIT SUBSTATIONS

ASSET DESCRIPTION / PURPOSE

Hydro One currently has a fleet of 35 MUSs. MUSs have similar components to a distribution station, however the components are mounted on a trailer (see example depicted in Figure 16). The MUS fleet is primarily utilized for:

- Emergency power restoration in the event of a transformer or other station component failure.
- Carrying the station load during maintenance and capital activities.

Figure 16: Picture of Mobile Unit Substation

When MUSs are deployed for emergency restoration, they are typically deployed to stations, installed, and connected (where connection structures are available at the station) to restore the interrupted load. On average it takes 6.6 hours for an MUS to travel to a station and be connected. Depending on the magnitude of work required to repair or replace the failed equipment, MUS deployment duration can range from a few days to a year. The replacement of failed transformer bushings is an example of emergency work where an MUS would be deployed for a few days. MUS deployments for the replacement of failed transformers can last up to a year if the transformer replacement requires long lead-time activities (e.g., rental or procurement of adjacent land for a crane to access the failed transformer).

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

MUSs include two key components - the transformer and the trailer. The age distribution for these two components of the MUSs is shown in Figures 17 and 18.

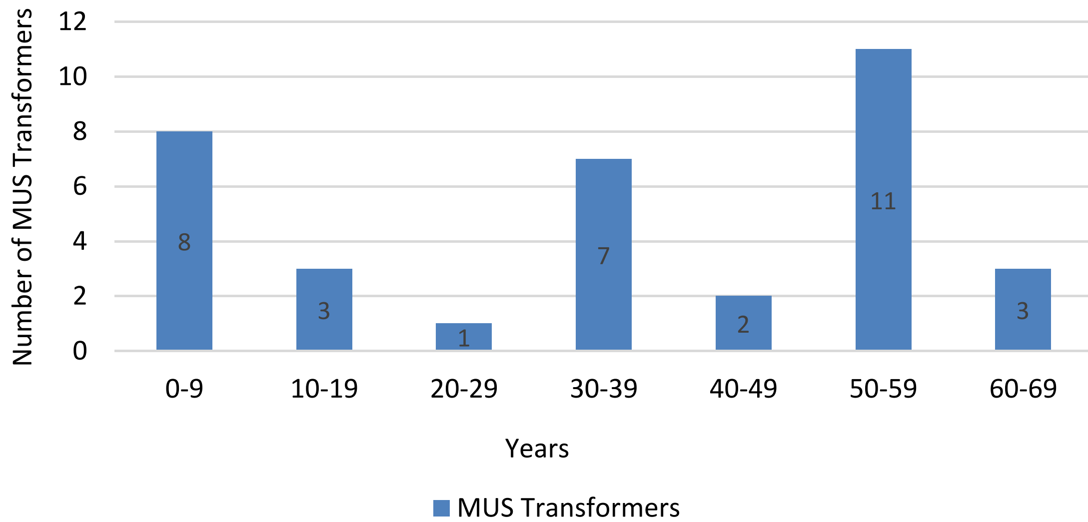


Figure 17: Demographics of the Mobile Unit Substation Transformers

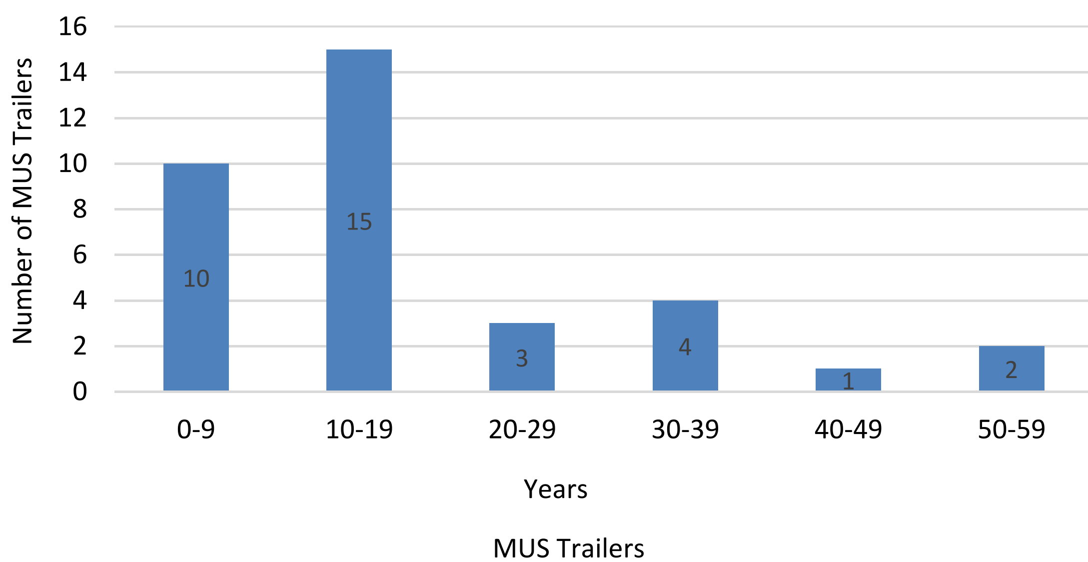


Figure 18: Demographics of the Mobile Unit Substation Trailers

The average age of the MUS transformers is 34 years and currently 46% of the MUS transformers are beyond their ESL of 40 years. The average age of the MUS trailers is 17 years, and currently 23% of the MUS trailers are beyond their ESL of 25 years. It is important to note that age does not drive the replacement of MUSs.

ASSET CONDITION

Failure modes and condition defects of MUSs include the typical defects that station transformers, switches, fuses and reclosers experience. Additional defects that MUSs can experience include trailer defects such as rust, worn suspension, brakes or landing gear and damage to MUS feeder connection cables. Currently, 40% of the MUS transformers and 26% of the MUS trailers are in poor condition, as shown in Figures 19 and 20.

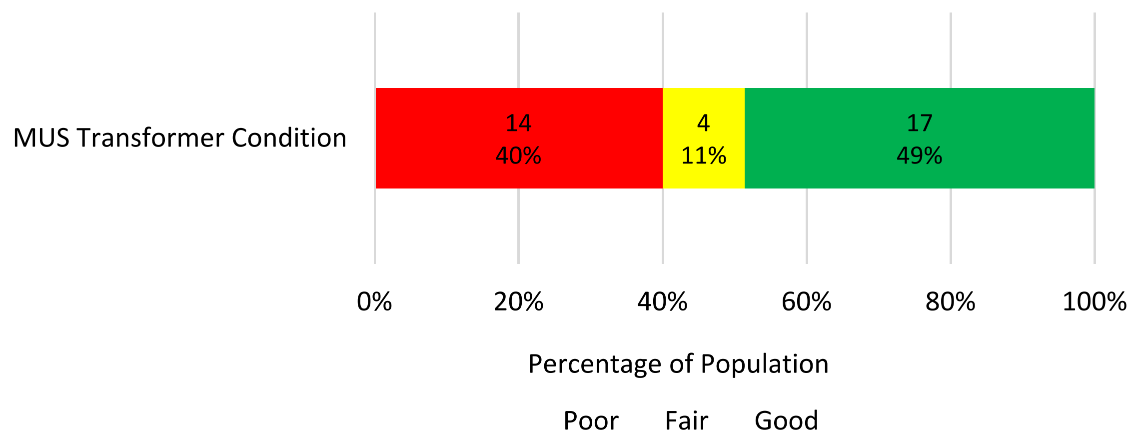


Figure 19: MUS Transformer Condition

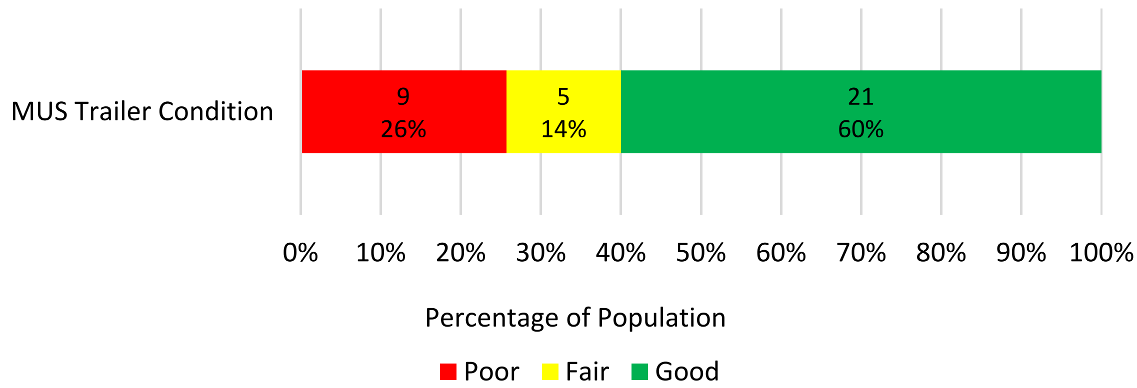


Figure 20: MUS Trailer Condition

ASSET PERFORMANCE

From 2011 to 2020, two MUS transformers failed. The MUS #35 transformer failed in 2014 and the MUS #26 transformer failed in 2018. The trailers for both MUSs were in poor condition and the decision was made at the time to retire these two MUSs. These two MUSs have been replaced with newer units.

LIFECYCLE STRATEGY

Hydro One's asset strategy for the MUS fleet over the 2023-2027 planning period is as follows:

1. Replace MUS transformers that are in poor condition and installed on trailers that are in good condition.
2. Replace entire MUSs when MUS transformers and trailers are in poor condition.
3. Procure one additional MUS to enable more capital projects and DS maintenance work.

The appropriate size of MUS fleet is determined based on having MUSs which can be deployed to stations to support failures and to have sufficient MUSs to allow for the completion of planned and unplanned capital and maintenance work. The five year capital investment plan includes the replacement of six MUS transformers, the replacement of two MUSs and expanding the MUS fleet by one unit. The ISD containing details on the investment in new MUS units is SR-02.

INSPECTION & MAINTENANCE PRACTICES

MUS trailers require an Ontario Ministry of Transportation (MTO) annual inspection certificate and undergo a mandatory annual inspection to that end.

Because the MUSs are a critical component of the distribution system (relied upon for emergency restoration, capital projects and maintenance work), each MUS receives an annual inspection and full maintenance of all electrical components each year. The maintenance activities for the MUS transformers, switches, fuses, reclosers and other electrical components are the same as for those installed in stations, other than the higher (annual) frequency.

Replacement & Refurbishment

MUS transformers follow a similar strategy to station transformers. MUS transformers that are in poor condition based on inspections or oil sample results are considered for repair or replacement. Younger MUS transformers in poor condition are typically candidates for corrective repair. Performing corrective repairs on younger transformers normally allows them to reach their 40 year ESL. Poor condition MUS transformers beyond their 40 year ESL tend to be candidates for replacement as opposed to corrective repair because performing a corrective repair on an older transformer may only slightly extend its service life, which would not be economical as more components are expected to break and need to be further addressed. However, it is important to note that the repair versus replacement decision is not driven solely by age but also accounts for the extent of the corrective work required. MUS transformers are only replaced and installed on the same trailers if the trailers are in good condition.

MUS trailers undergo minor corrective repairs such as painting to address surface rust, or replacement of fenders or wheels. Trailers determined to be in need of replacement are typically those with rust that has penetrated through the metal or not expected to pass MTO annual inspections. In cases where both the MUS transformer and MUS trailer are in poor condition and are determined to be in need of replacement, these MUSs will be retired and replaced with a new MUS.

3.2.2.5 OTHER STATION ASSETS

ASSET DESCRIPTION / PURPOSE

In addition to the above-noted station assets, Hydro One distribution station assets also encompass station structures, MUS connection structures, fences and gates, grounding systems, station service transformers, insulators and bus. Stations equipped with breakers or vacuum electronic reclosers also have protection relays or intelligent electronic devices (IEDs). Stations identified as having high environmental risk can be equipped with spill containment systems.

- *Station Structures* are used in stations for mounting electrical components such as switches, fuses, reclosers, station service transformers, bus, and IEDs. Some station structures are wooden, though most are made of steel.
- *MUS Structures* provide a connection point for MUS cables to be connected and allow the station power equipment to be by-passed. These structures are typically wooden.
- *Fences* separate live station equipment from the public to maintain public safety, while gates are used as an entry point for Hydro One maintenance vehicles, construction vehicles and staff. Most station fences are chain link, though some are wooden.
- *Grounding Systems* are used in stations to safely dissipate fault currents into the ground in the event of equipment failure, to protect Hydro One employees and the public.
- *Station Service Transformers* are used to transform distribution system voltages to 120 V to supply station equipment such as IEDs and receptacles.
- *Insulators* provide electrical insulation between live equipment and grounded station structures. They are also used to mount the power equipment to the station structures.
- *Bus* work in stations is used to electrically connect the power equipment within the station.
- *Spill Containment Systems* are typically present in stations that have a high spill risk. These spill containment systems contain transformer oil in the event of a transformer tank rupture.
- *Protection Relays* in stations are used to trip feeder breakers in the event of a system fault.
- IEDs are used to control electronic vacuum reclosers, directing the reclosers when to open and close during system faults.

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

The approximate count of these other station components are shown in Table 5 below:

Table 5 - Other Distribution Station Components

Station Component	Units
Station Structures	2,143
MUS Structures	787
Fences	992
Station Grounding Systems	992
Station Service Transformers	644
Insulators	unknown
Bus Work	1,095
Spill containment systems	103
Protection Relays	156
IEDs	444

ASSET CONDITION

The condition profile of *station structures* is show in Figure 21:

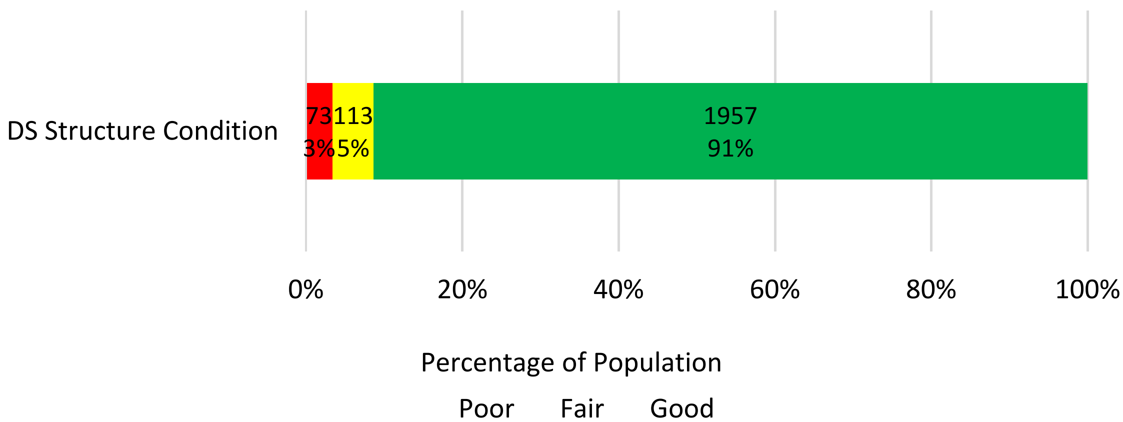


Figure 21: DS Station Structure Condition

Poor condition station structures are typically addressed under station refurbishment projects (DSP Section 3.11, D-SR-04). In instances where there is an imminent risk of failure, station structure components will be replaced under a demand capital program (DSP Section 3.11, D-SR-01).

The condition profile of *MUS structures* is shown in Figure 22:

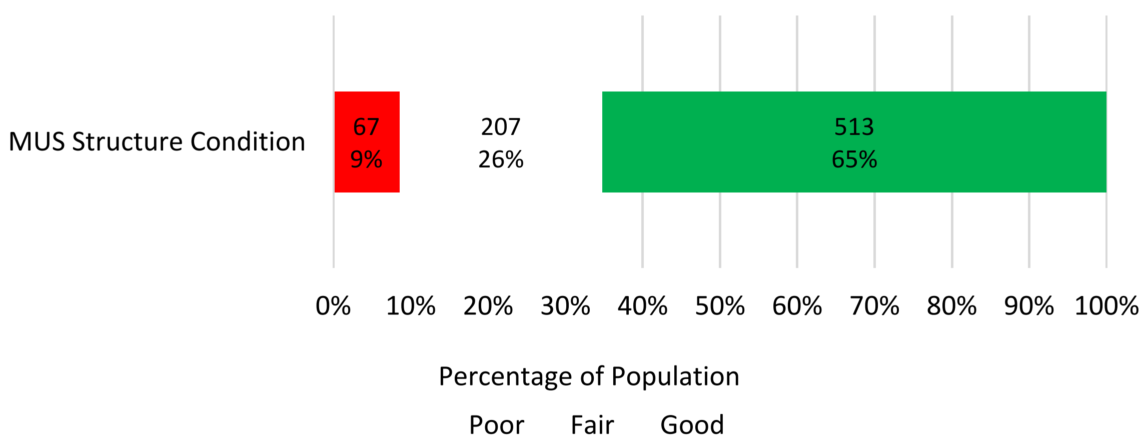


Figure 22: MUS Structure Condition

Poor condition MUS structures are typically replaced under a planned component replacement program (DSP Section 3.11, D-SR-03), or are bundled in station refurbishment projects (DSP Section 3.11, D-SR-04). In instances where there is an urgent need to replace a poor condition MUS structure, it may be addressed through the demand capital program (DSP Section 3.11, D-SR-01).

The condition profile of station *fences* is shown in Figure 23:

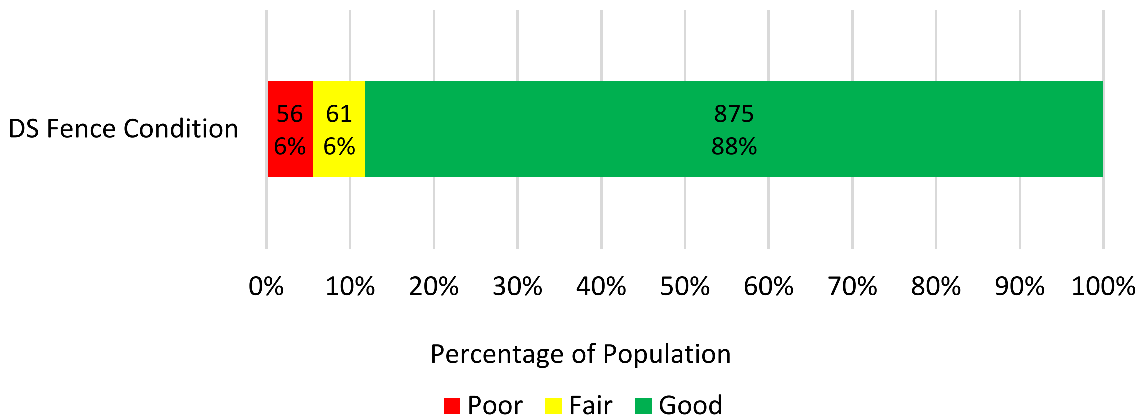


Figure 23: DS Station Fence Condition

Poor condition fences are typically replaced under station refurbishment projects (D-SR-04). In instances where there is an urgent need to replace a poor condition fence, it may be addressed through the demand capital program (DSP Section 3.11, D-SR-01).

The condition profile of *station service transformers* is shown in Figure 24:

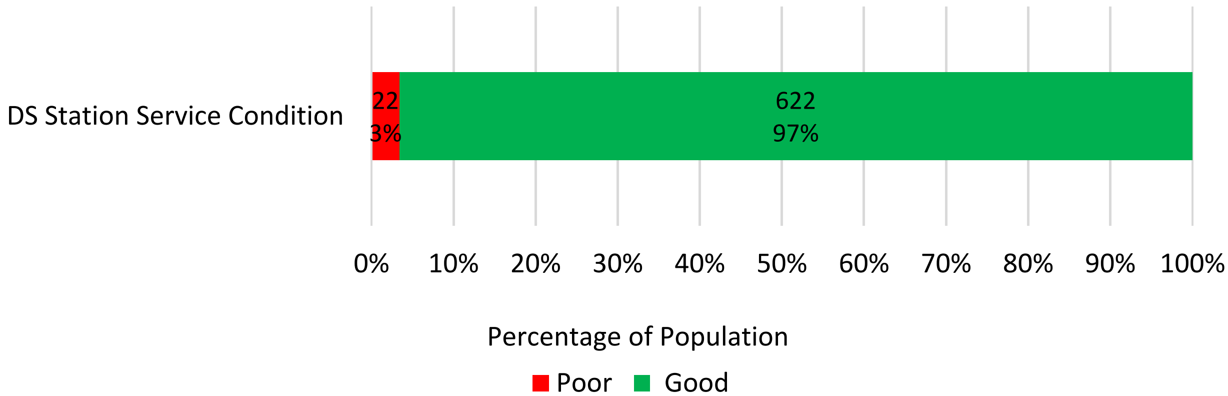


Figure 24: DS Station Service Condition

Poor condition station service transformers are typically addressed under station refurbishment projects (DSP Section 3.11, D-SR-04). In instances where there is an urgent need to replace a station service transformer, it may be addressed through the demand capital program (DSP Section 3.11, D-SR-01).

The condition profile of bus work is shown in Figure 25:

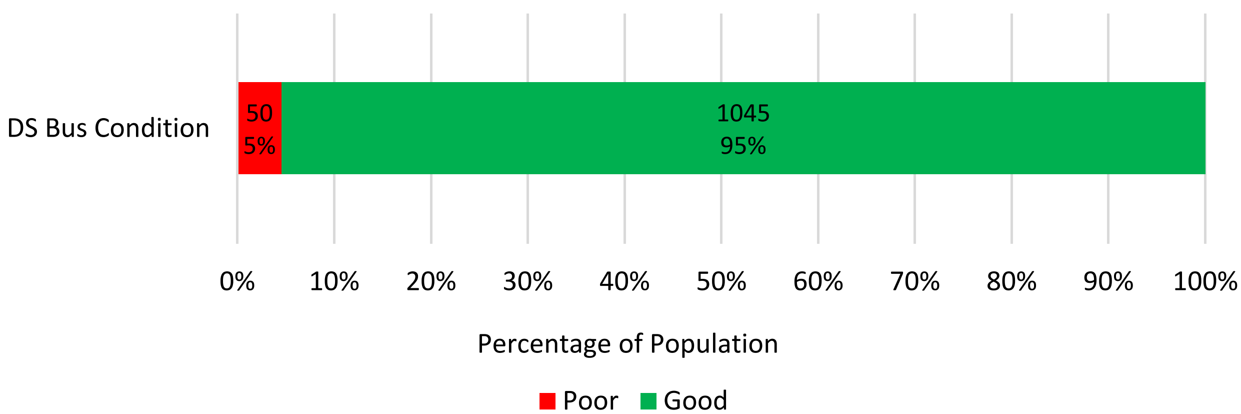


Figure 25: DS Station Bus Condition

Poor condition bus is typically bundled with transformer replacements under station refurbishment and demand capital projects (refer to DSP Section 3.11, D-SR-04 and D-SR-01).

The condition profile of spill containment systems is shown in Figure 26:

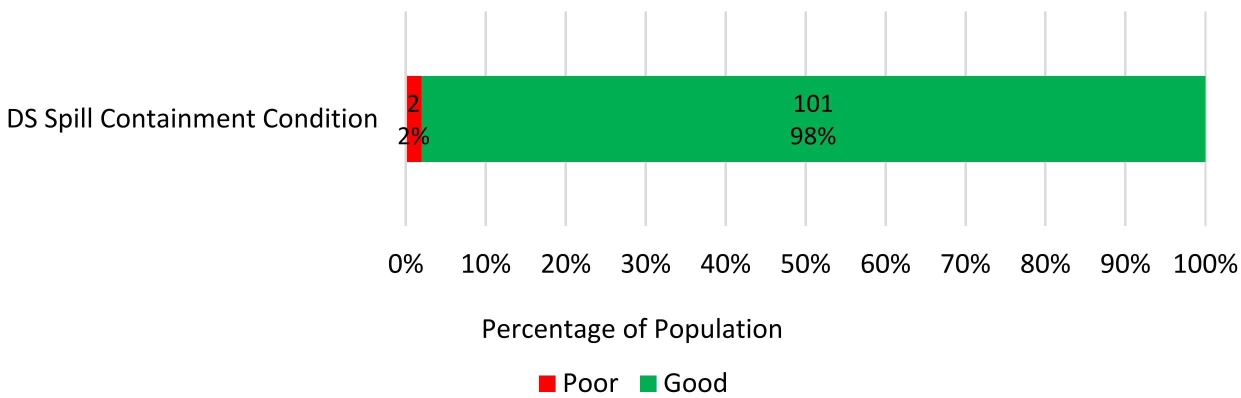


Figure 26: DS Spill Containment Condition

Poor condition spill containment systems are typically repaired under corrective maintenance programs.

Protection Relays & IEDs are replaced when they fail under corrective maintenance activities as they are critical for feeder protection. As a result, there is no condition profile for these assets.

LIFECYCLE STRATEGY

INSPECTION & MAINTENANCE PRACTICES

These additional station assets are generally inspected for defects during routine station visual inspections. The live electrical components will also undergo a thermography inspection. If any defects are identified, they are addressed as corrective maintenance work where practical.

REPLACEMENT & REFURBISHMENT

Following routine inspections of these station components, any components that are defective and cannot be repaired will be planned for replacement through planned and demand component replacement programs or bundled with station refurbishment projects.

3.2.3 ASSET COMPONENT INFORMATION – DISTRIBUTION LINES

Hydro One operates and maintains power system assets associated with over 123,000 circuit kilometres of distribution lines, which are critical to the reliable delivery of power to over 1.4 million distribution customers across the province. Distribution line assets include:

- Poles
- Cross Arms
- Conductors
- Line Transformers
- Rights of Way

3.2.3.1 POLES

ASSET DESCRIPTION / PURPOSE

The structural integrity of a distribution line is largely dependent on the poles that support the line. These poles keep the electrical equipment a safe distance from the ground and other objects. Hydro One owns, maintains and operates approximately 1.6 million poles, 99.3% of which are wood poles and 0.7% are steel, composite, and concrete poles. In addition, Hydro One maintains and operates overhead lines that are supported by approximately 400,000 poles owned by joint use partners.

Wood is currently the most cost effective material for the majority of pole applications. In some situations, a composite pole may need to be used[2], however these poles are more expensive than wood for all sizes on the distribution system. Based on the company's overhead distribution standards, Hydro One's distribution engineering technicians select the appropriate size and class of pole and framing components based on the span lengths, conductor sizing, equipment sizing, and loading angles.

[2] Pursuant to Hydro One's Overhead Distribution Standards, composite poles are utilized in areas prone to woodpecker or insect damage and low lying areas that may be prone to water damage.

Wood deteriorates over time as it is exposed to the environment. Ground line rot is the most common natural aging failure mode for wood poles. Mechanical damage (from cars, snowplows, etc.) as well as animal damage including woodpecker and insects will also shorten the life of a pole.

To mitigate natural deterioration over time, poles are initially treated with Chromated Copper Arsenate (CCA) in advance of installation. This chemical fixes within the pole to prevent rot from developing over time. Figure 27 shows a cross section of a treated pole. The green colored section is the CCA-treated soft wood shell of the pole. The central lighter colored section is the untreated heartwood.

Figure 27: Treated Wood Pole Cross Section

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

Figure 28 shows the current demographics of the Hydro One pole population. The average age of poles is 40.2 years. There are currently 378,000 poles (23%) that are 60 years of age or older. Over the 2023 to 2027 planning period, the number of poles 60 years or older would increase to 500,000 poles (31%) in the absence of pole replacements.

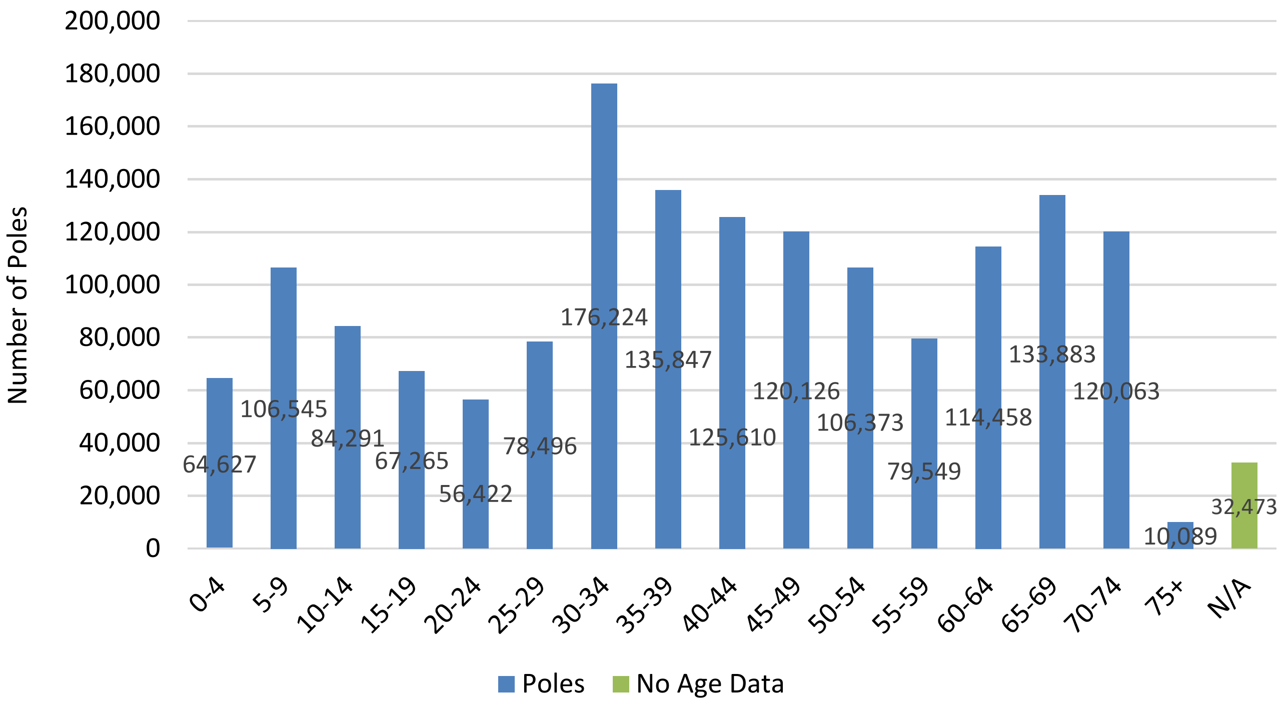


Figure 28: Demographics of Hydro One Owned Distribution Poles

ASSET CONDITION

Pole condition is assessed as part of regular inspections (performed as part of vegetation management inspections) and the wood pole test and treat programs. Poles that have failed a test or have severe visual damage are considered to be in poor condition and require either refurbishment or replacement. Figures 29, 30, and 31 are examples of pole defects that require remedial action.

1 **Figure 29: Woodpecker Damage**

2

3 **Figure 30: Ground Line Surface Rot**

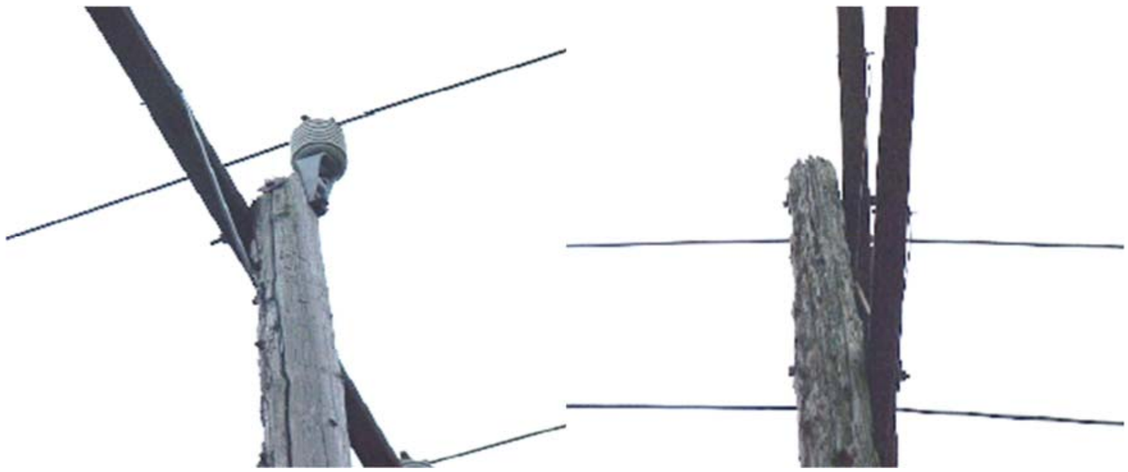


Figure 31: Pole Top Damage

Figure 32 shows the breakdown of the condition ratings of Hydro One distribution poles as determined based on observed defects or testing results. There are approximately 79,000 poles that are in poor condition and require replacement or refurbishment. The remainder of the poles are in good or fair condition and poles in these two categories are not treated differently in that neither are proactively planned for replacement or refurbishment. Another 50,000 poles are forecast to become poor condition in the 2023 to 2027 period.

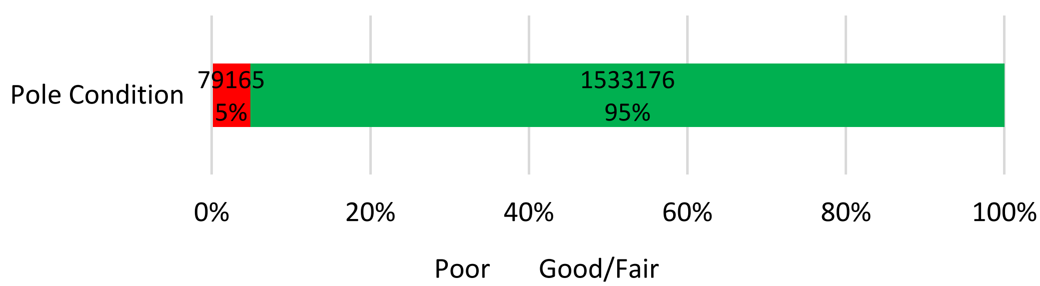


Figure 32: Pole Condition

ASSET PERFORMANCE

Due to the nature of Hydro One's largely radial distribution system, pole failures directly impact customer reliability. The number of interruptions attributed to pole failures has been increasing at a steady rate between 2011 and 2020. Figure 33 shows that the number of outages attributed to pole failures has increased from 134 in 2011 to 360 in 2020. At the same time, the contribution of pole failures to the overall impact of customer interruptions has remained relatively flat in the last 10 years (see Figures 34 and 35). This indicates that fewer customers are being impacted on average per pole failure – a result that is consistent with the expected outcome of Hydro One's ongoing efforts to prioritize investments based on the RSE methodology. Specifically with respect to poles, Hydro One prioritizes poles with the highest impact to reliability risk to be addressed through the Pole Sustainment program (DSP Section 3.11, D-SR-07). However, it is important to recognize that it has only been a few years since the start of Hydro One's efforts to prioritize poles with the highest reliability impact, and the number and reliability impact of pole failures can fluctuate from year to year.

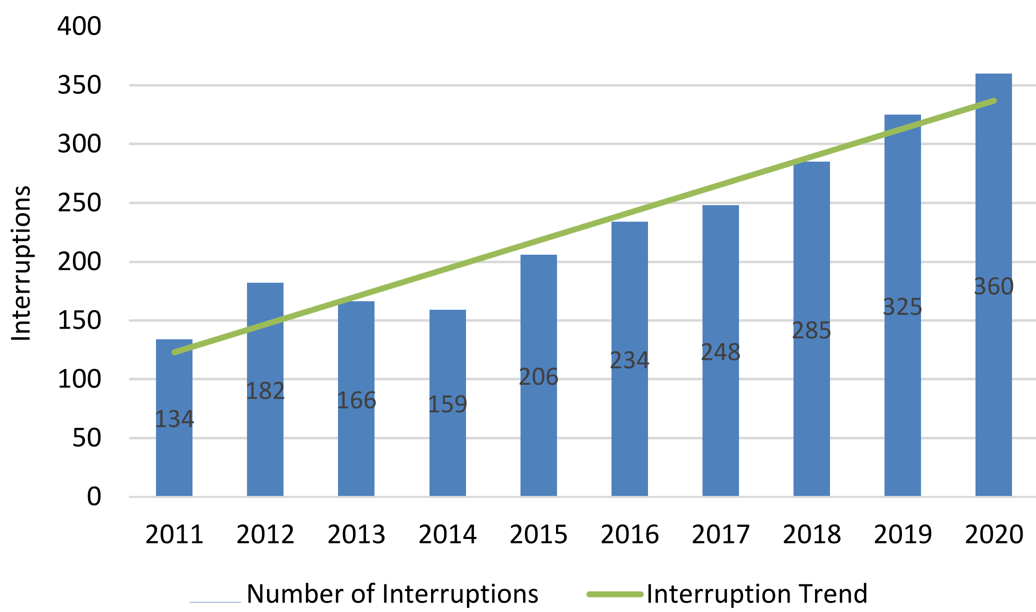


Figure 33: Pole Caused Interruptions Excluding FM

Between 2011 and 2020, the total SAIDI due to unplanned replacements of failed poles has been as low as 9 minutes in 2013 and as high as 23 minutes in 2015. On average the contribution has been 13 minutes. The following graph illustrates the annual SAIDI impact from unplanned equipment caused outages that resulted in at least one pole being replaced on normal operating days (excluding FM outages).

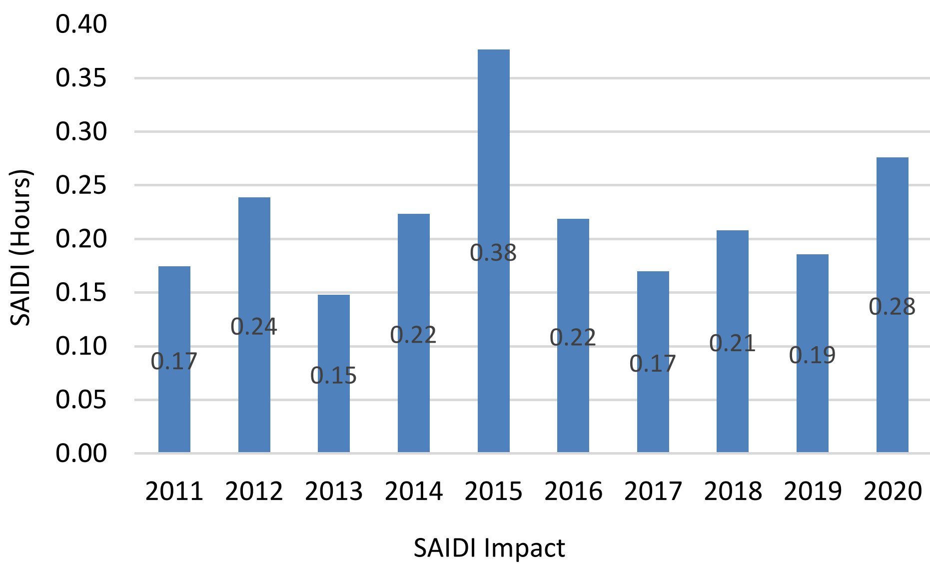


Figure 34: Pole Caused SAIDI (excluding FM)

Figure 35 shows the System Average Interruption Frequency Index (SAIFI) impact of outages over the 2011-2020 period that resulted in poles being replaced. The annual contribution has been as low as 0.03 in 2011 and as high as 0.06 in 2015 and on average the SAIFI contribution has been 0.04 per year.

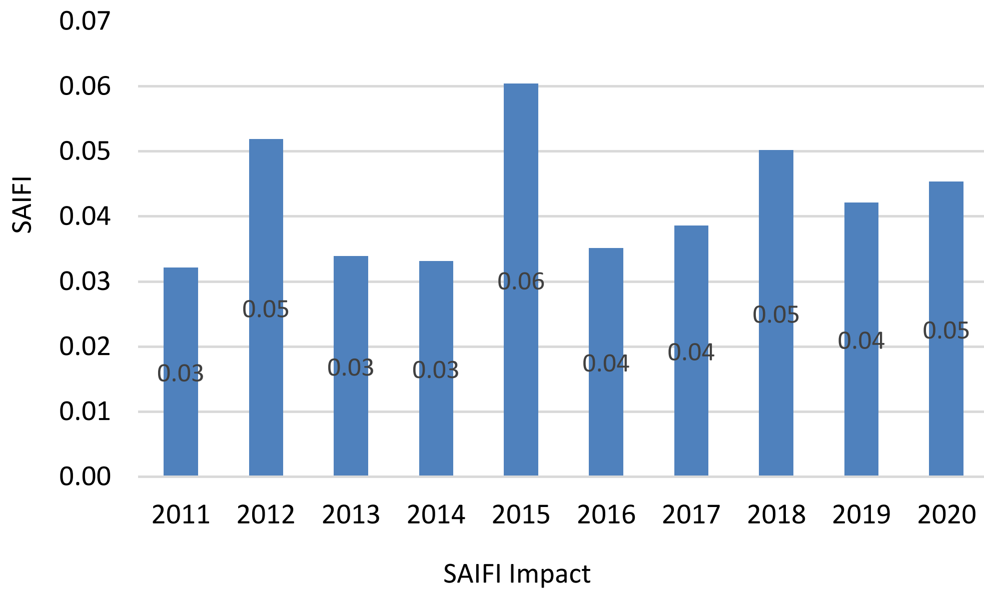


Figure 35: Pole Caused SAIFI Excluding FM

LIFECYCLE STRATEGY

Inspection & Maintenance Practices

Poles are required to be inspected every six years for rural areas and three years for urban areas as specified in the DSC, Appendix C. In 2019, the inspection program was combined with the forestry planning process. This means that the structures are inspected in line with Hydro One's Optimal Cycle Protocol (OCP) (see section 3.2.3.5). These inspections are primarily intended to identify visual deficiencies on the pole, including woodpecker holes, mechanical surface damage, surface rot, severe leaning, or even broken poles. Other defects identified on the lines are also recorded during the inspections, including damaged cross arms, insulator defects, and missing guys.

In 2020, Hydro One began to collect additional condition data as part of its pole test and treat program. This program will test and treat 103,000 poles per year on a 15 year cycle. A pole test consists of hammering the pole to identify any hollow sections, drilling the pole in three locations to measure the remaining shell thickness, measuring the depth of any significant surface damage, and measuring any circumference reductions over time. These quantitative measurements are used to calculate a percent remaining strength. The data collected from this activity will supplement pole condition data and to help identify additional poles that require replacement or poles that can be mechanically refurbished.

REPLACEMENT & REFURBISHMENT

Refurbishment

In 2020, Hydro One Distribution introduced two new refurbishment programs: (i) chemical refurbishment that is completed as part of the pole test and treat program and (ii) mechanical refurbishment completed under the mechanical refurbishment program.

As part of the test and treat program, a copper borate rod is inserted into the holes that were drilled to test the pole. These rods defuse over time into the wood to rejuvenate the initial treatment at the ground line. Sufficient levels of chemical preservative at the ground line prevents rot and fungal growth and helps to extend the overall life of the pole.

If a pole had deteriorated at the ground line only, it may be a good candidate for mechanical refurbishment. Mechanical refurbishment involves installing one or two steel structure braces to support the pole (see example depicted in Figure 36). This activity will extend the life of the existing pole for potentially 20 years or more and delay the replacement of the pole until the steel structure has deteriorated or the pole becomes damaged in another area that the steel can no longer support. Installing this steel structure support requires less labour and is less expensive than replacing the pole. In order for a pole to be eligible for mechanical refurbishment, it requires suitable soil conditions, no joint use attachments, and adequate shell thickness measurements to ensure there is sufficient structural strength above the ground line. When the pole's poor condition is isolated to the ground line area and the characteristics of the pole and ground line allow for it, mechanical refurbishment is a cost effective means of addressing risk associated with poles in poor condition.

Figure 36: Mechanically Refurbished Pole

Replacement

Hydro One's primary program for replacing poles in poor condition is the wood pole sustainment program. Poles which have failed a condition assessment are considered for planned replacement under this program. These poles are selected based on the risk assessment discussed in DSP Section 3.7 and DSP Section 3.11, D-SR-07 (Pole Sustainment Program). Poles that do not undergo planned replacement and fail structurally during the plan period would be replaced as part of the trouble program. Hydro One also replaces poles through other planned investments based on system needs, including voltage conversions, sustainment projects, addressing system growth, and joint use and relocations, which all contribute to the renewal of Hydro One's pole fleet. However, these other investments do not target poor condition poles and historically only 2% of poles addressed under these other planned investments required replacement also due to their condition.

3.2.3.2 CROSS ARMS

ASSET DESCRIPTION / PURPOSE

In conjunction with poles, overhead conductor is often supported by cross members known as "cross arms". Cross arms are typically made of wood, though composite and steel cross arms are utilized when increased strength is required.

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

Hydro One's distribution system contains approximately 500,000 cross arms. Cross arms are replaced based on their condition, and age data is not collected or maintained for this asset type.

Asset Condition

Cross arms are visually inspected on a regular basis, and broken, cracked, or otherwise damaged cross arms are identified (see example depicted in Figure 38). Approximately 16,700 cross arms are identified as being in poor condition (Figure 37).

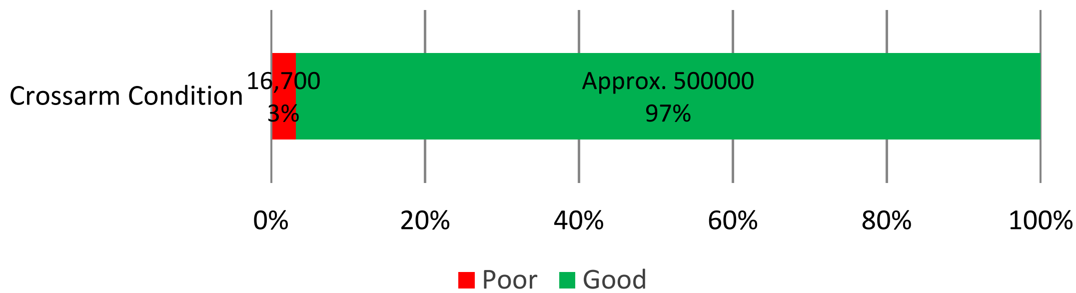


Figure 37: Cross Arm Condition

Figure 38 – Cross Arm in Poor Condition

Asset Performance

As with poles, the radial nature of Hydro One's distribution system means that when cross arms fail, they typically cause an outage that cannot be restored until the cross arm is replaced. The overall reliability impact of cross arm failures, however, is relatively low. From 2011 to 2020, the average number of outages attributed to cross arm failures has been 74 per year, with an average SAIDI and SAIFI contribution of 0.09 hours and 0.02 interruptions, respectively. Figures 39, 40 and 41 provide the number of interruptions, SAIDI and SAIFI contributions attributed to cross arm failures, excluding interruptions during force majeure events. While the volume of interruptions in recent years has been higher than historical levels, the SAIDI and SAIFI impact of these outages has been decreasing since 2018, indicating a lower number of customers being impacted per interruption.

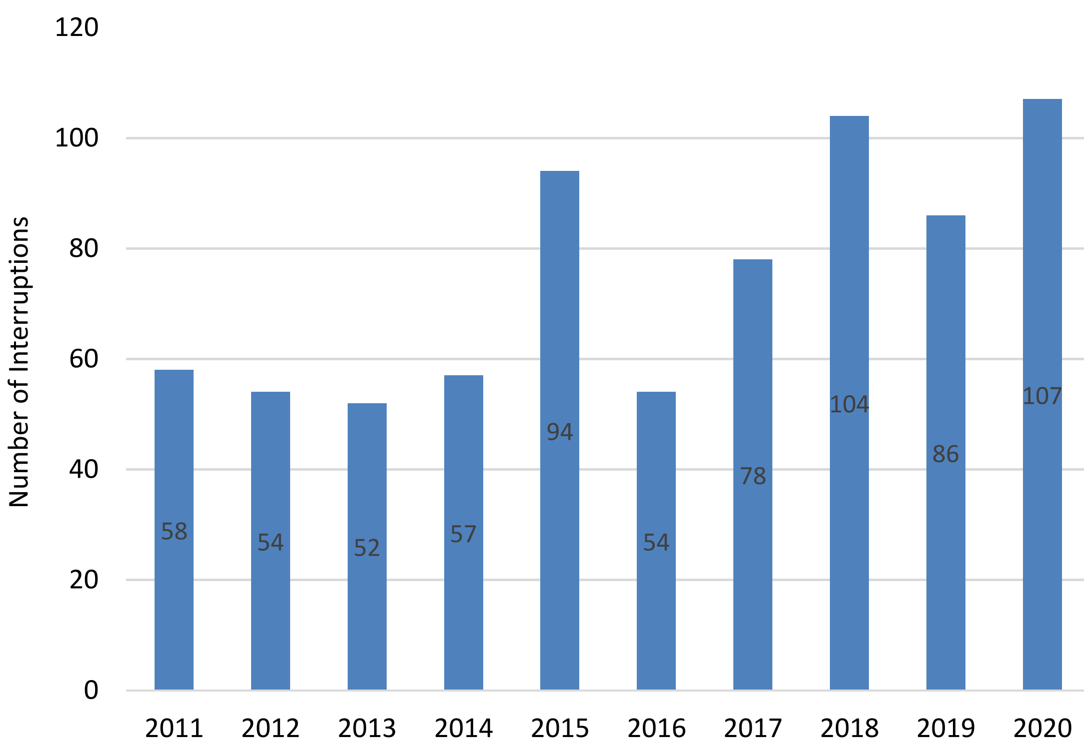


Figure 39: Number of Interruptions Attributed to Cross Arm Failures (Excluding FM)

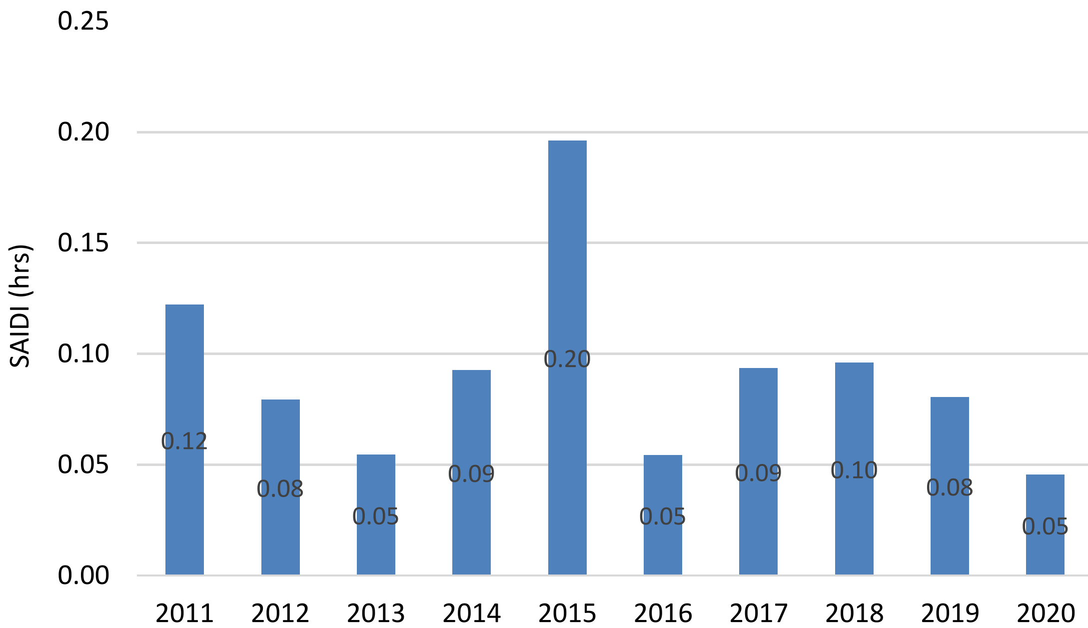


Figure 40: SAIDI Contribution of Interruptions Attributed to Cross Arm Failures (Excluding FM)

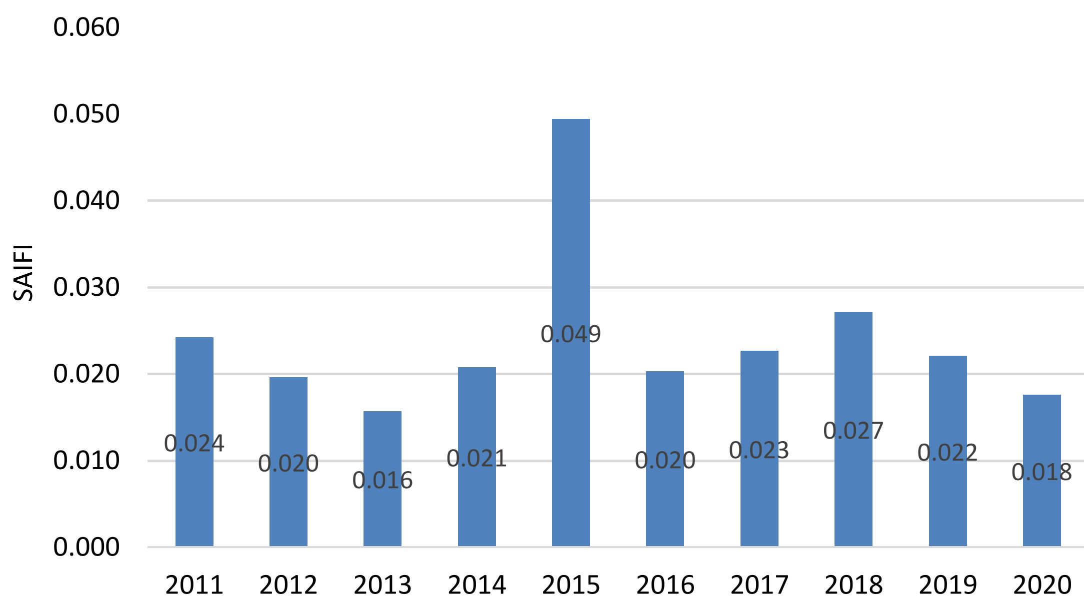


Figure 41: SAIFI Contribution of Interruptions Attributed to Cross Arm Failures (Excluding FM)

LIFECYCLE STRATEGY

Inspection & Maintenance Practices

Cross arms are subject to the same six-year (rural)/three-year (urban) inspection requirements as other distribution lines assets. These inspections primarily consist of visual assessments as part of an integrated line and vegetation assessment activity, as discussed in Exhibit E-03-02. Broken, cracked or otherwise damaged cross arms are identified as part of these inspections.

Replacement

Hydro One's dedicated program for replacing cross arms in poor condition is the cross arm replacement program. Cross arms identified as being in poor condition are candidates for inclusion in this program. Cross arms are selected for inclusion in the program based on the projected impact of failure. Cross arms that do not undergo planned replacement and fail during the plan period would be replaced as part of the trouble program.

Hydro One also replaces cross arms through other investments, including the pole replacement program, voltage conversions, addressing system growth, and joint use and relocation activities. All such activities contribute to the renewal of Hydro One's cross arm fleet.

3.2.3.3 CONDUCTORS

ASSET DESCRIPTION / PURPOSE

As it relates to distribution lines, conductor generally refers to one or more strands of a conducting metal used to connect the distribution network. The main focus of this section is the *primary* conductor, which refers to conductor that connects the distribution network to the primary side of a service transformer. Hydro One owns and operates approximately 123,000 circuit kilometres of primary conductor on its distribution system.

Conductor can be further classified by the nature of its installation. Conductor that is supported by poles generally consists of a series of bare metal wires, and is referred to as *overhead conductor*. Conductor that is buried underground is generally in the form of a cable which consists of both a phase conductor and a neutral conductor separated by an insulating material, and is referred to as *underground cable*. While the majority of existing underground cables in the Hydro One distribution system are direct buried, beginning in 2019, new underground cable installations have moved to an all-in-duct design. This design will simplify ongoing maintenance and streamline future replacement of underground cables. Conductor that is partially or fully installed underwater is also generally in the form of a cable consisting of both a phase conductor and a neutral conductor separated by an insulating material, and is referred to as *submarine cable*.

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

Hydro One's distribution system contains a total of 123,000 circuit kilometers of primary line of the following conductor types:

- Overhead conductor: 113,000 km
- Underground cable: 6,000 km
- Submarine cable: 4,000 km

ASSET CONDITION

Overhead Conductor

Overhead conductor is visually inspected on a regular basis as part of an integrated line and vegetation assessment activity, where broken strands, severe corrosion, insufficient clearance and other conductor defects are identified. There are currently approximately 11,000 overhead conductor defects identified on the distribution system.

Underground Cable

Underground cable is visually inspected on a regular basis via dedicated underground system patrols, and exposed or damaged cables are identified. There are currently approximately 2,400 underground cable defects identified on the distributions system.

Submarine Cable

Submarine cables are visually inspected on a regular basis via dedicated submarine patrols, and exposed or damaged cables are identified. There are currently approximately 400 “exposed” submarine cables defects, along with approximately 600 “damaged” submarine cable defects. Figure 42 shows examples of exposed and damaged submarine cables.

Figure 42: Example of (Left) an Exposed Cable Showing Initial Signs of Corrosion, and (Right) a Corroded Cable with Significant Damage

ASSET PERFORMANCE

Overhead Conductor

Overhead conductor failures are typically due to external forces (e.g., trees failing into conductors). These types of failures are not attributed to the conductor. Nonetheless, there are situations where an overhead conductor itself fails, for example, at a splice. From 2011 to 2020, there have been an average of 639 interruptions directly attributed to overhead conductor failures per year, with an average annual SAIDI and SAIFI contribution of 0.28 hours and 0.07 interruptions, respectively. Figures 43, 44, and 45 provide the number of interruptions, SAIDI and SAIFI contributions attributed to overhead conductor failures, excluding interruptions during force majeure events.

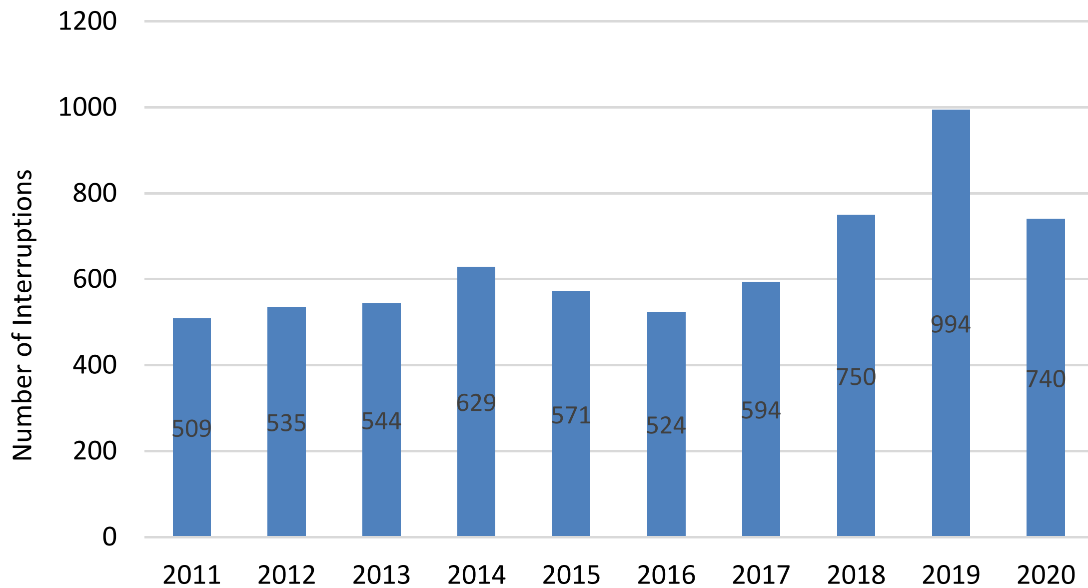


Figure 43: Number of Interruptions Attributed to Overhead Conductor Failure (Excluding FM)

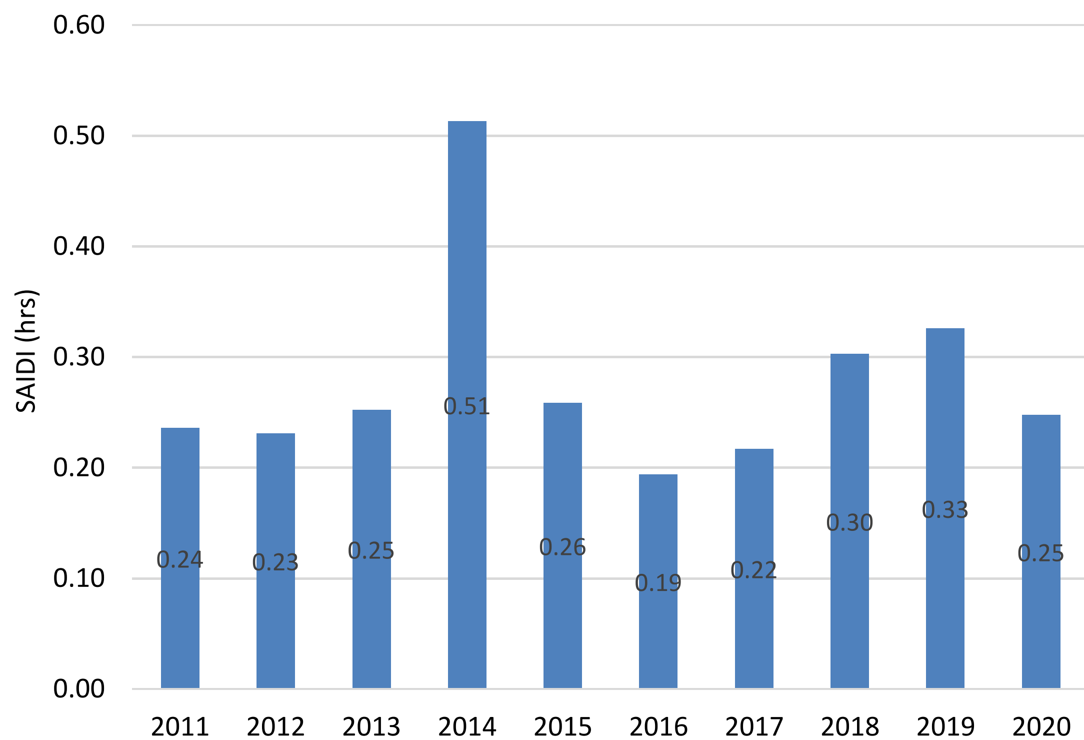


Figure 44: SAIDI Contribution of Interruptions Attributed to Overhead Conductor Failure (Excluding FM)

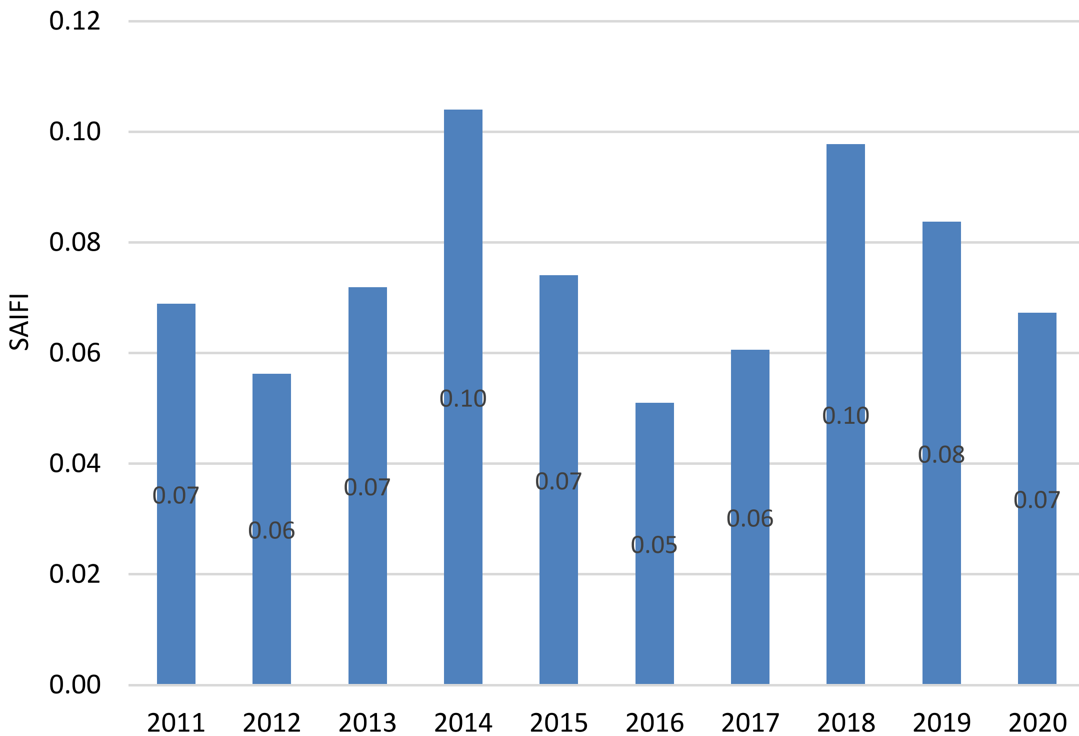


Figure 45: SAIFI Contribution of Interruptions Attributed to Overhead Conductor Failure (Excluding FM)

Underground Cable

Due to the nature of their installation, underground cables are generally protected from foreign interference, including weather related damage. As a result, underground cables tend to experience good reliability for the majority of their service lives. As cables age, however, electrical stresses can begin to cause breakdown of the cable insulation, leading to faults and other power quality issues. From 2011 to 2020, there have been an average of 68 interruptions attributed to underground cable failures per year, with an average annual SAIDI and SAIFI contribution of 0.012 hours and 0.035 interruptions, respectively. Figures 46, 47, and 48 provide the number of interruptions, SAIDI and SAIFI contributions attributed to underground cable failures, excluding interruptions during force majeure events.

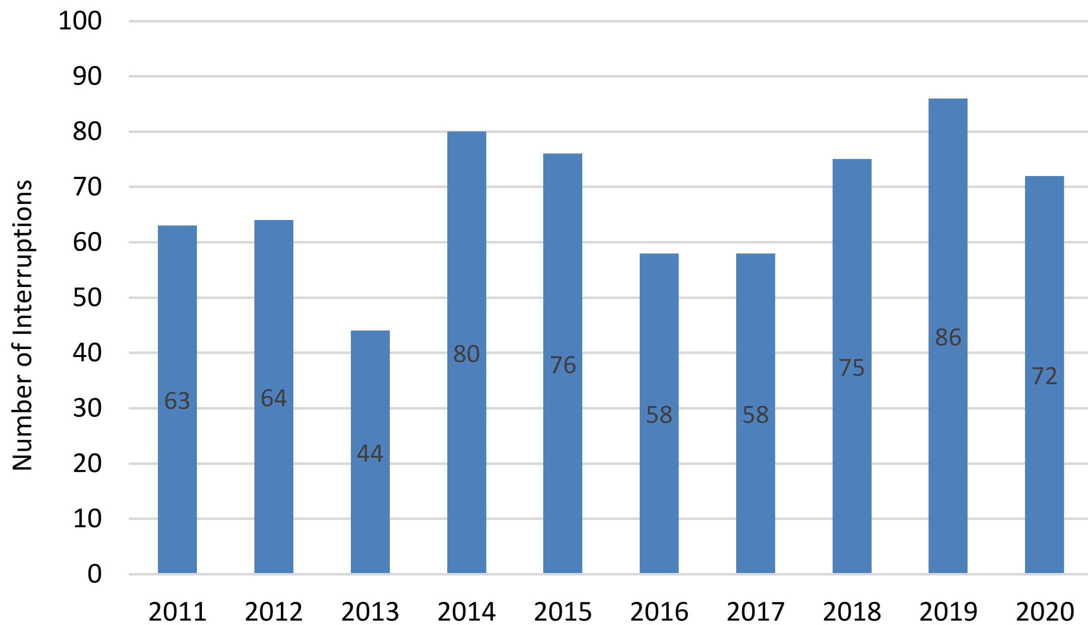


Figure 46: Number of Interruptions Attributed to Underground Cable Failure (Excluding FM)

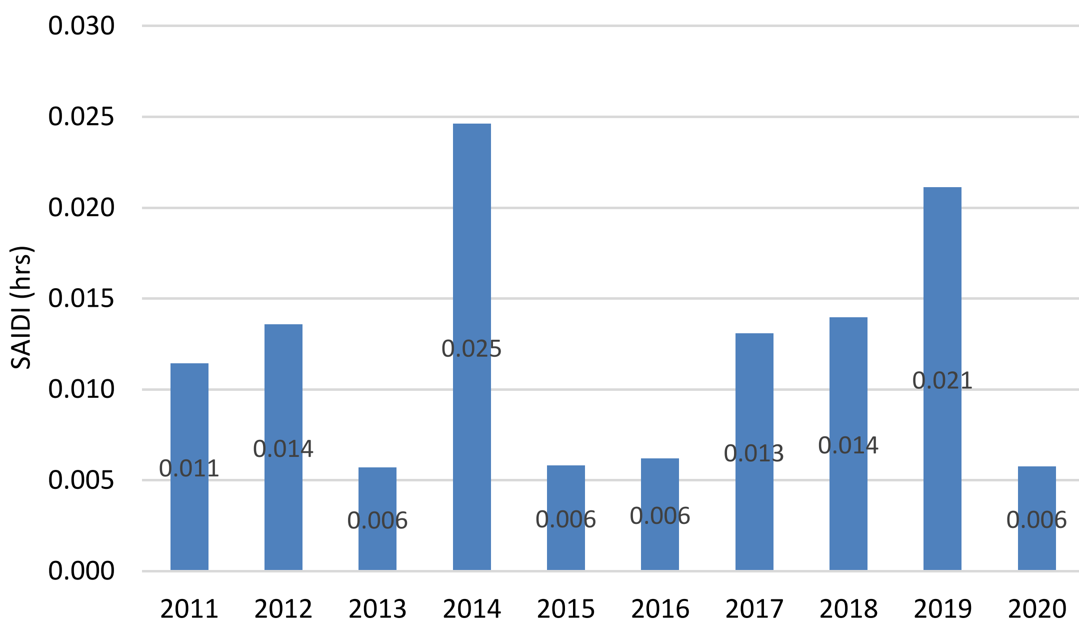


Figure 47: SAIDI Contribution of Interruptions Attributed to Underground Cable Failure (Excluding FM)

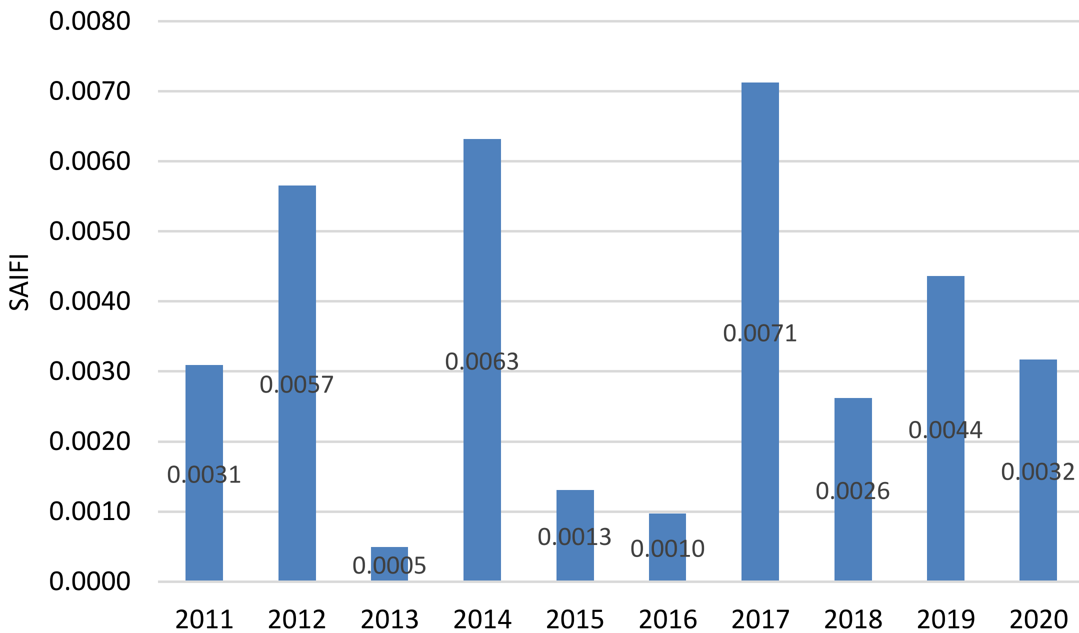
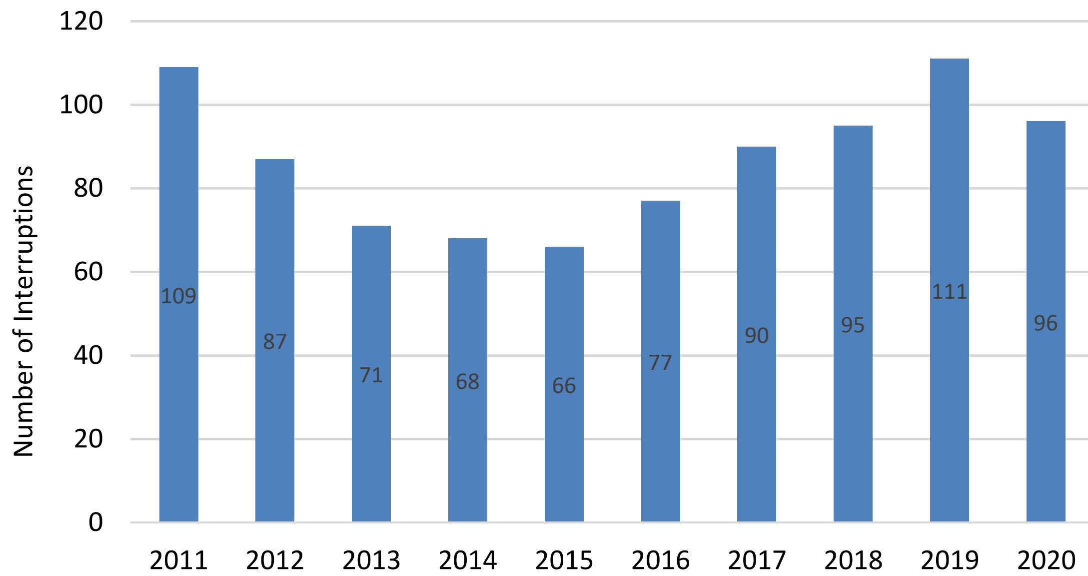


Figure 48: SAIFI Contribution of Interruptions Attributed to Underground Cable Failure (Excluding FM)

Submarine Cable

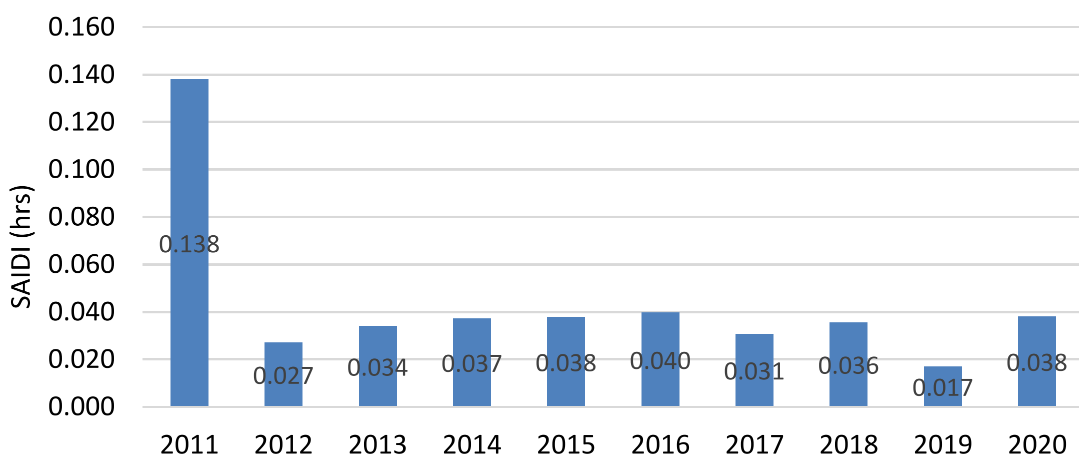
Submarine cable is primarily used to supply island dwellings or substitute for overhead water crossings where such crossings are not technically or economically feasible. Submarine cable applications are often characterized by relatively low customer density and loading. As a result, cable failures usually impact a low number of customers. From 2011 to 2020, there have been an average of 87 interruptions attributed to submarine cable failures per year, with an average annual SAIDI and SAIFI contribution of 0.043 hours and 0.027 interruptions, respectively. Figures 49, 50, and 51 provide the number of interruptions, SAIDI and SAIFI contributions attributed to submarine cable failures, excluding interruptions during force majeure events.

While the impact to overall system reliability of submarine cables is small, the inaccessibility of submarine cables during the winter season can lead to situations where a failed cable can result in an extended outage for the affected customers. These situations are rare, but can lead to an unusually high customer impact to a small group of customers, as occurred in 2011.



1 **Figure 49: Number of Interruptions Attributed to Submarine Cable Failure (Excluding FM)**

2



3 **Figure 50: SAIDI Contribution of Interruptions Attributed to Submarine Cable Failure**
4 **(Excluding FM)[3]**

[3] 2011 saw an unusually high number (11) of long duration (>100 hour) outages attributed to submarine cable failures. These were typically due to failed cables being inaccessible due to winter conditions, and which could not easily be repaired or replaced until spring. Customers were notified and accepted the outages due to the seasonal nature of these properties.

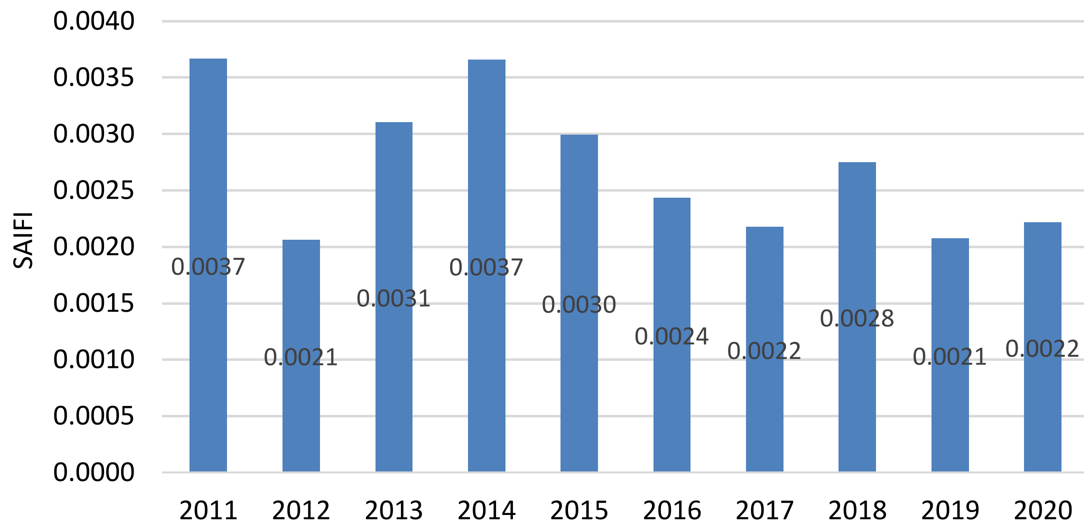


Figure 51: SAIFI Contribution of Interruptions Attributed to Submarine Cable Failure (Excluding FM)

LIFECYCLE STRATEGY

INSPECTION & MAINTENANCE PRACTICES

Overhead Conductor

Overhead conductor is subject to the same six-year (rural)/three-year (urban) inspection requirements as other distribution lines assets. These inspections primarily consist of visual assessments by technicians as part of an integrated line and vegetation assessment activity. Broken strands, severe corrosion, and other conductor defects would be recorded as part of these inspections.

While some advanced testing techniques are available to evaluate the condition of overhead conductor, these are complex and generally not cost-effective for distribution lines. As a result, unless there is a specific need, detailed conductor testing is not typically performed.

Underground Cable

Underground cables are subject to the same six-year (rural)/three-year (urban) inspection requirements as other distribution lines assets. Dedicated underground system inspections are scheduled to meet these requirements. Since underground cables are not typically accessible, these inspections primarily consist of visual assessment of cables within enclosed equipment (e.g., pad-mounted switchgear) and the connections between cables and such equipment as well a visual identification of cables that have become exposed.

While some advanced testing techniques are available to evaluate the condition of underground cables, these are typically complex and require the cables to be taken out of service. As a result, unless there is a specific need (such as evaluating the cable for suitability of cable injection), detailed cable testing is not typically performed.

Submarine Cable

Submarine cable inspections are subject to the same six-year (rural)/three-year (urban) inspection requirements as other distribution lines assets. Dedicated submarine system inspections are scheduled to meet these requirements. As part of the submarine cable inspection, a detailed visual inspection of the submarine cable is completed to identify any damage to the concentric neutral of the cable. This inspection is essential in areas that have a high likelihood of public contact (i.e. near swimming, boating or other recreational areas). In addition, any other defects that are present are recorded.

In some cases, if the cable is at a location that has the potential of public contact, and a visual inspection cannot be completed, a Time Domain Reflectometer (TDR) test can be performed to verify the condition of the cable.

REPLACEMENT & REFURBISHMENT

Refurbishment

Overhead Conductor

Overhead conductor requires repair when it becomes damaged, either naturally over time (e.g., due to corrosion) or as a result of a specific event that causes damage (e.g., vegetation contact or third party vehicle contact). Repairs can be completed by splicing new sections of conductor in place of the damaged sections.

Underground Cable

Underground cables require repair when their insulation has failed, when they experience damage due to a "dig-in", or when an existing splice fails. These repairs are done by either replacing a small section of cable or installing a splice at the point of failure. If a cable cannot be repaired due to technical, physical and/or cost constraints, it must be replaced.

Submarine Cable

If an inspection reveals one or more of the following conditions, a submarine cable is considered to have sustained damage requiring emergency response:

- Over 75% of the concentric neutral cross section is missing or broken
- A non-standard temporary repair of the neutral has been made
- Any other condition that is deemed to pose a hazard

Typically, a response to concentric neutral damage would include repairing the submarine cable. If such a repair cannot be feasibly completed or would not mitigate the identified hazard, the damaged cable would require immediate replacement.

Replacement

Overhead Conductor

Due to the relatively long service life and less complex repair of overhead conductor, replacement of large sections of conductor alone is not generally driven by condition. Rather, conductor is usually replaced as part of feeder renewal or line relocation projects, or as a result of line upgrades that require higher capacity conductor.

Underground Cable

Due to the relatively low reliability impact of underground cable failures, renewal of underground cables is based on a run-to-failure approach. Cables are only replaced when they fail and cannot be suitably repaired.

In 2018, an innovative approach to extend the life of underground cables was piloted in the Orleans area. This approach involves injecting cables with a proprietary fluid in order to fill defects in the cable insulation that may have developed over time. Cable injection, where feasible, represented a 65% savings compared to traditional cable replacement. Cable injection can be a viable solution to extend the life of aging underground cables in an efficient manner. Over the 2023 to 2027 plan period, Hydro One will continue cable injection across its service territory.

Submarine Cable

Hydro One replaces submarine cables that are identified as being in substandard condition or that otherwise pose safety risks. Depending on the circumstances, a cable may be fully or partially replaced (i.e. by splicing a new section). For example, localized cable damage on a newer, otherwise good cable may be addressed by a partial replacement of the cable.

Hydro One also renews submarine cable mechanical protection where a cable is otherwise in good condition but is missing such protection. Regardless of whether a cable is fully replaced, partially replaced, or if mechanical protection is being installed, at the completion of the work, the cable installation must conform to Hydro One Underground Distribution Standards which outline the installation requirements for submarine cable.

3.2.3.4 LINE TRANSFORMERS

ASSET DESCRIPTION / PURPOSE

Distribution Line Transformers are used to convert electricity from primary distribution voltage levels (e.g., 44 kV, 27.6 kV, 12.48 kV) to secondary voltage levels (e.g., 600 V or 240 V/120 V) so the power can be utilized by residential and small business customers.

Depending on the proximity of adjacent customers, each single-phase pole top or pad mounted transformer may supply one or several customers at 240 V/120 V. A three-phase pole top or pad mounted transformer generally supplies a single customer at 600 V/347V or 208 V/120 V.

Figure 52: Picture of Pole-Top Line Transformer

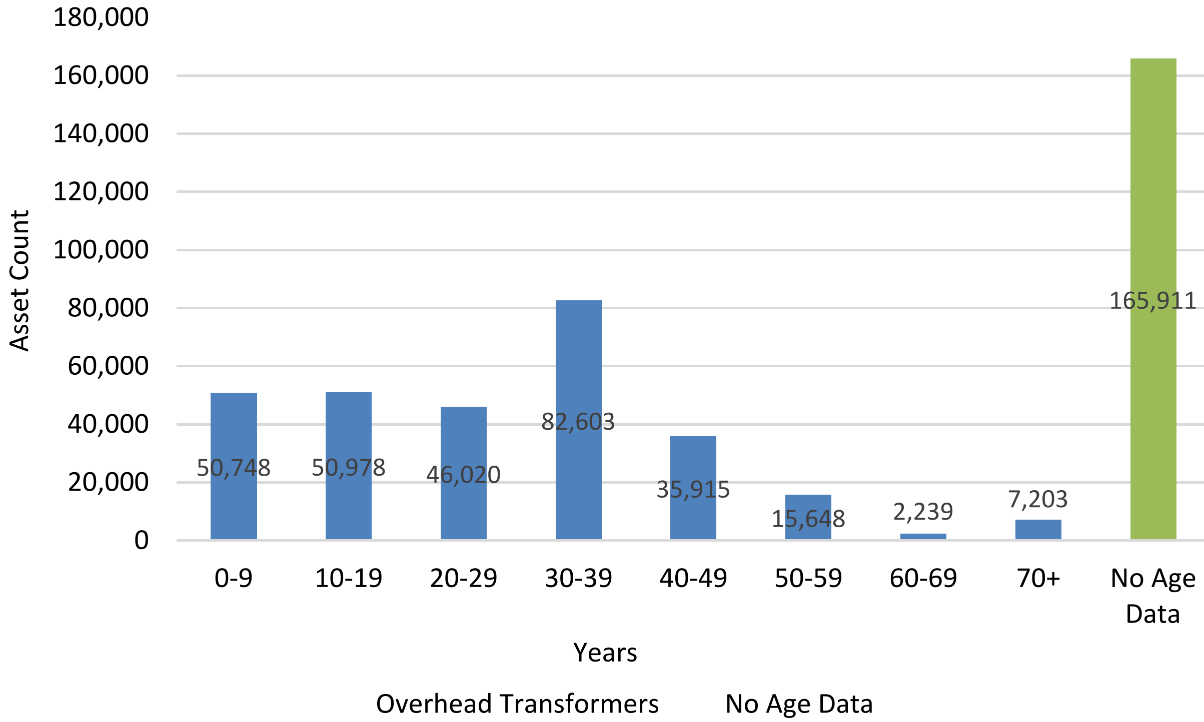
ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

ASSET DEMOGRAPHICS

Hydro One maintains a total fleet of approximately 522,000 transformers in overhead (pole mounted) or underground (pad mounted, submersible, transclosure or pole-transformer) configurations. Table 6 provides a breakdown of the approximate number of transformers by type, and Figures 53 and 54 provide the age profile of overhead and underground transformers, respectively.

1 **Table 6 - Line Transformer Type**

Transformer Type	Quantity
Overhead: Pole Mounted Transformers	457,000
Underground: Pad Mounted Transformers	64,000
Underground: Submersible Transformers	150
Underground: Transclosures and Pole-Transformers	800



2 **Figure 53: Overhead Transformer Demographics**

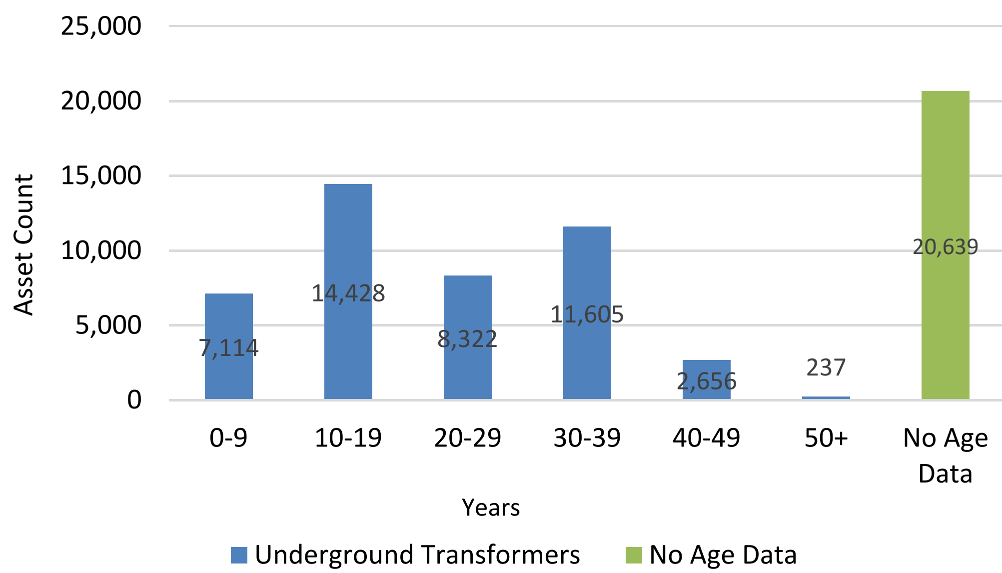


Figure 54: Underground Transformer Demographics

ASSET CONDITION

The primary consideration in assessing line transformer condition is internal degradation due to the electrical stresses placed upon it, including both the normal loading of the transformer, as well as abnormal electrical events (e.g. electrical faults or lightning strikes on the feeder supplying the transformer).

Due to the limited number of customers served by a line transformer, and given the cost of internal condition assessment relative to the replacement cost of the transformer, it is not cost effective to assess the condition of either overhead or underground distribution line transformers. As a result, asset condition is not available for these assets.

ASSET PERFORMANCE

Overhead Transformers

Due to the low density of Hydro One's distribution system, overhead transformers typically supply a limited number of customers. As a result, individual transformer failures have a small impact on overall customer reliability and system performance. From 2011 to 2020, there have been an average of 1,167 interruptions attributed to overhead transformer failures per year, with an average annual SAIDI and SAIFI contribution of 0.016 hours and 0.003 interruptions, respectively. Figures 55, 56, and 57 provide the number of interruptions, SAIDI and SAIFI contributions attributed to overhead transformer failures, excluding interruptions during force majeure events.

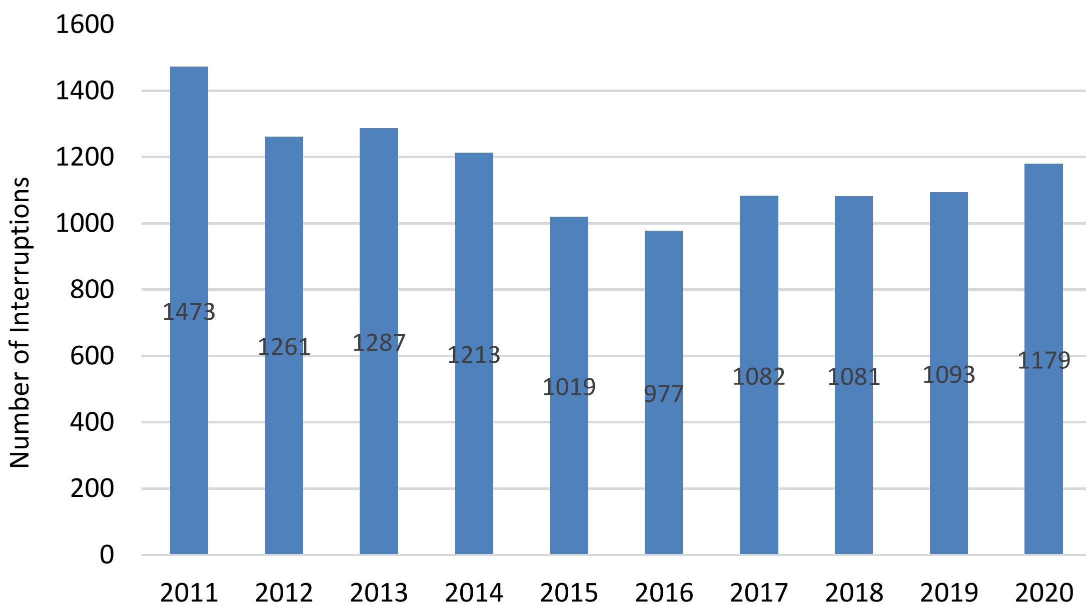


Figure 55: Number of Interruptions Attributed to Overhead Transformer Failures (Excluding FM)

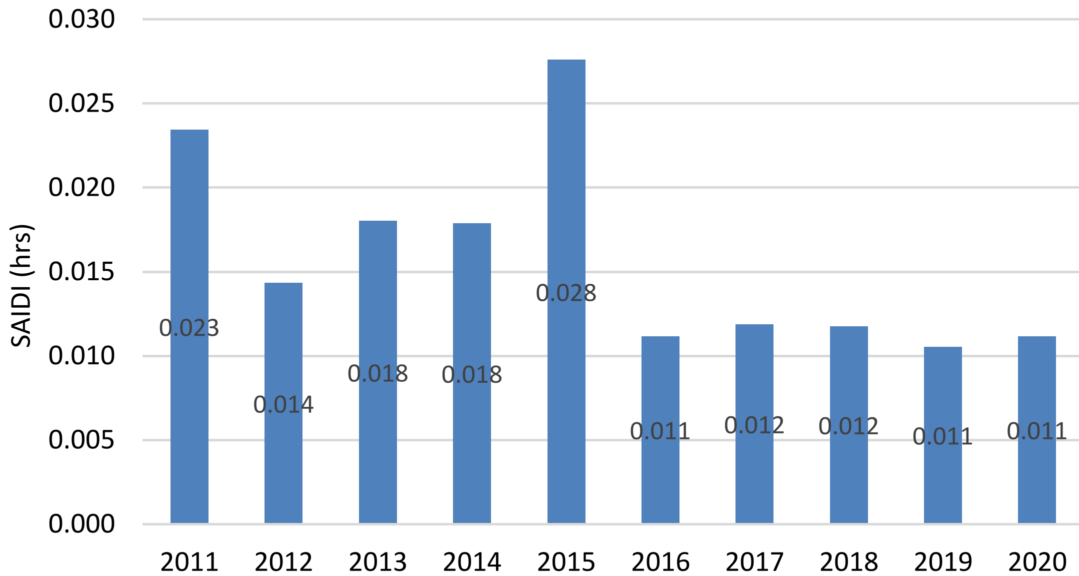


Figure 56: SAIDI Contribution of Interruptions Attributed to Overhead Transformer Failures (Excluding FM)

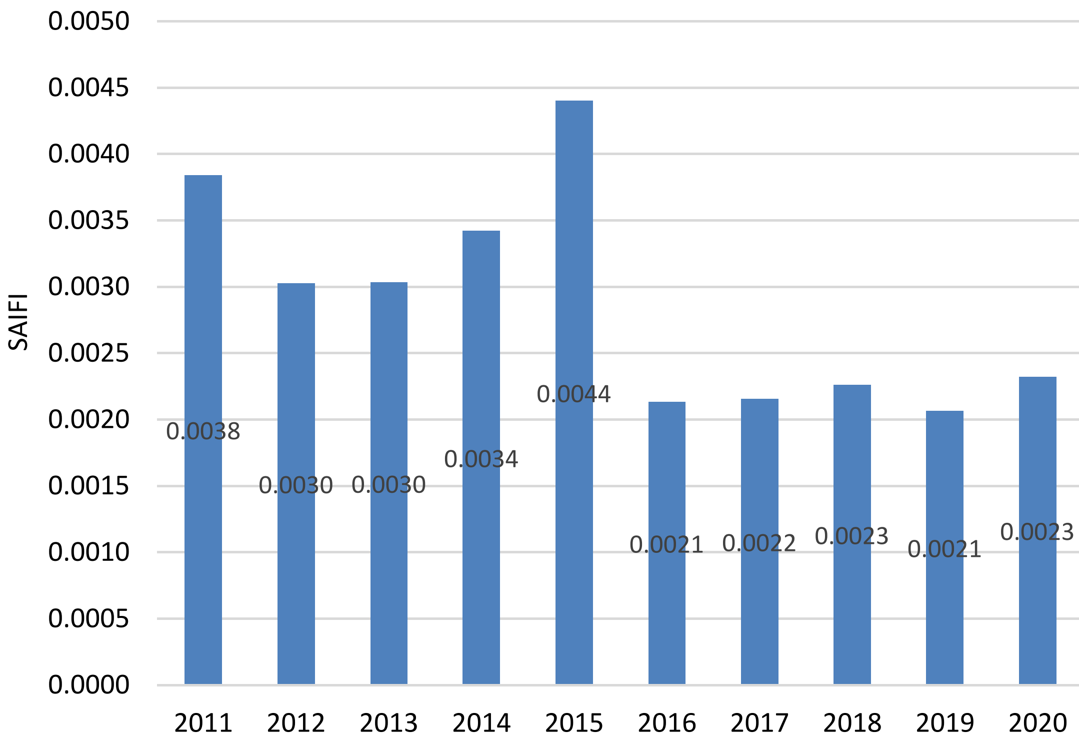


Figure 57: SAIFI Contribution of Interruptions Attributed to Overhead Transformer Failure (Excluding FM)

Underground Transformers

From 2011 to 2020, there have been an average of 72 interruptions attributed to underground transformer failures per year, with an average annual SAIDI and SAIFI contribution of 0.0024 hours and 0.0007 interruptions, respectively. Figures 58, 59, and 60 provide the number of interruptions, SAIDI and SAIFI contributions attributed to underground transformer failures, excluding interruptions during force majeure events.

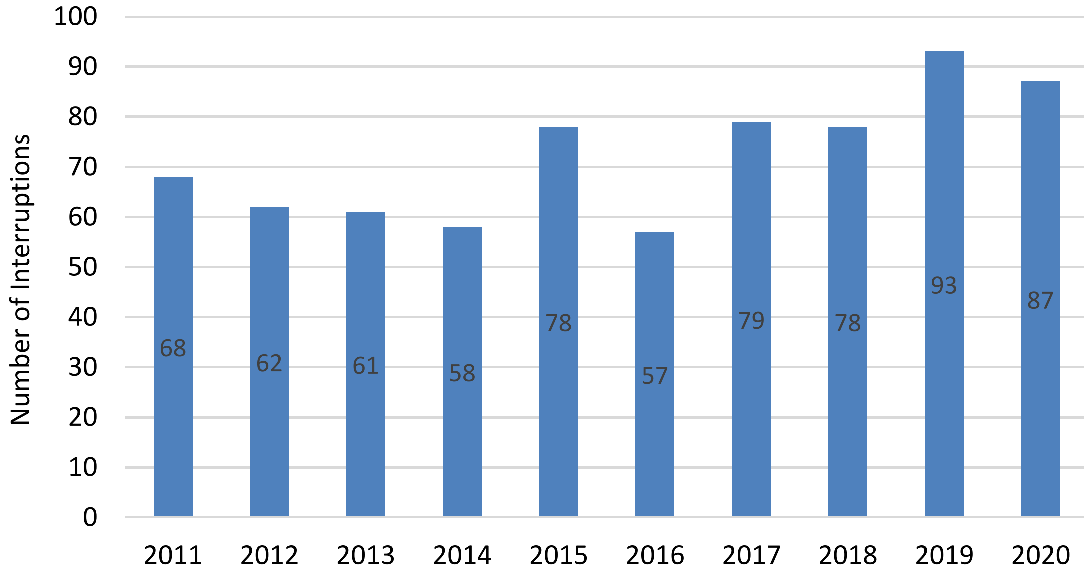


Figure 58: Number of Interruptions Attributed to Underground Transformer Failures (Excluding FM)

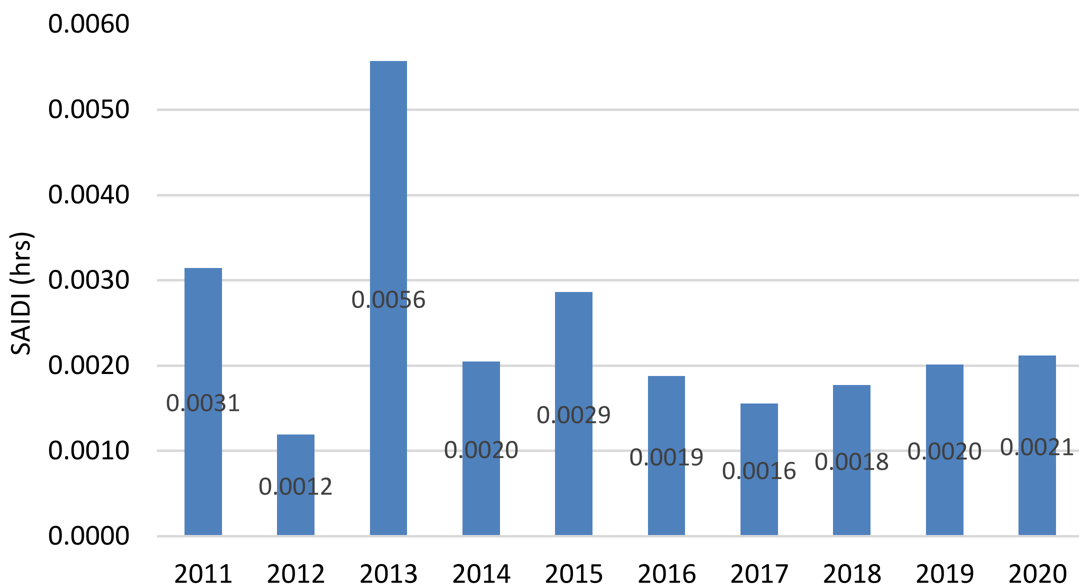


Figure 59: SAIDI Contribution of Interruptions Attributed to Underground Transformer Failures (Excluding FM)

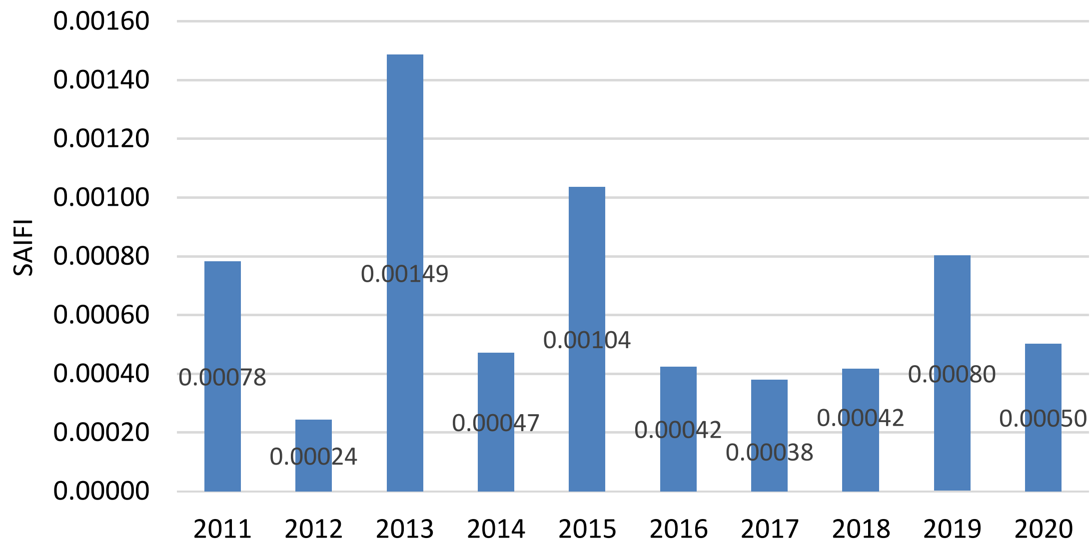


Figure 60: SAIFI Contribution of Interruptions Attributed to Underground Transformer Failures (Excluding FM)

LIFECYCLE STRATEGY

Distribution line transformers are generally run to failure and not proactively replaced due to:

- The high cost of condition assessment relative to asset replacement; and
- The relatively small reliability impact of failure due to the limited number of customers served and the ability to quickly replace failed transformers

However, there are situations when transformers are replaced before failure. These include:

- PCB contaminated transformers
- Substandard transformers that pose an unusually high reliability or safety risk
- Transformers replaced during the course of other work, for example, customer upgrades or voltage conversions

INSPECTION & MAINTENANCE PRACTICES

Distribution line transformers are subject to the same six-year (rural)/three-year (urban) inspection requirements as other distribution lines assets. These inspections primarily consist of visual assessments by technicians as part of an integrated line and vegetation assessment activity, as discussed in section 3.2.3.5.

Further, in order to support PCB-driven transformer replacements, a number of specific inspections are undertaken. Since the risk of PCB contamination is generally only present in transformers manufactured before 1981, manufacture dates are collected as part of the visual inspection. If transformers are found to be manufactured before 1981, oil samples are taken and analyzed for PCB contamination. For further details, please refer to Exhibit E-03-02.

REPLACEMENT & REFURBISHMENT

As discussed, distribution line transformers are run to failure, with the following exceptions:

- Transformers with a PCB concentration greater than 50 ppm, or which are older than 1981 and whose PCB levels cannot de determined, are replaced on a planned basis
- Transformers that are deemed to be substandard transformers and that pose an unusually high reliability or safety risk, are replaced on a planned basis
- Transformers are also replaced as a result of distribution feeder rebuilds, when they are damaged by external forces or when they pose an environmental hazard due to oil leakage.

3.2.3.5 RIGHTS OF WAY

ASSET DESCRIPTION / PURPOSE

Hydro One’s distribution system is comprised of approximately 123,000 circuit kilometers of lines built on about 105,000 km of right-of-way (ROW) spanning across the Province (Figure 61).

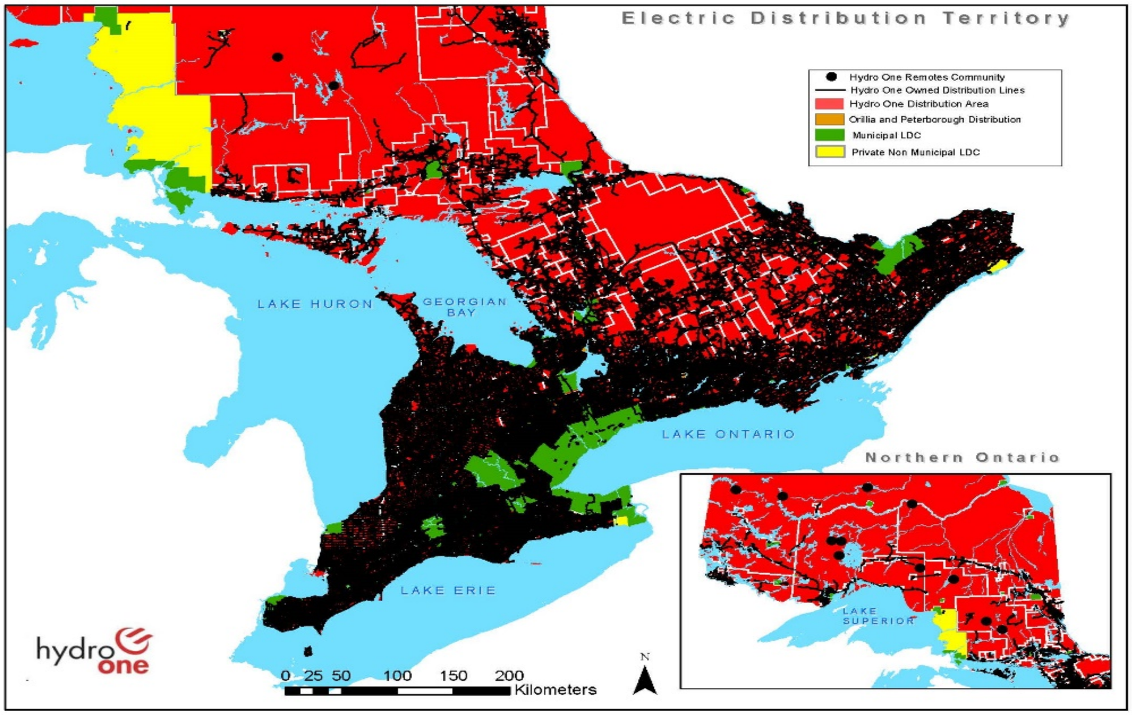


Figure 61: Map of Hydro One Distribution Asset Location

Adjacent to Hydro One's ROWs is a potential workload of millions of trees that are a significant cause of distribution outages.

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

ASSET DEMOGRAPHICS

Through its vegetation management program (referred to as the Optimal Cycle Protocol or OCP), Hydro One Distribution manages the reliability and safety risk created by incompatible vegetation along the ROWs. Prior to the initiation of OCP, Hydro One Distribution's vegetation management clearing was focused on full ROW clearing, managing an average of 10,890 kms annually (for 2006-2016), which implies a cycle length of approximately 9.5 years. Since the introduction of OCP in 2018, one of the key objectives was to reduce and optimize cycle times without increasing the overall cost of the vegetation management program.

Figure 62 below shows the year in which the ROW kms were last treated, as of year end 2020. Since the introduction of OCP, Hydro One has more than doubled the average number of kms managed every year. The cycle length of the vegetation management program can provide an indication of the "condition" of ROWs (i.e., number of vegetation defects requiring work, as further discussed below). The amount and species of vegetation along the ROW and climatic region of the Province all impact ROW condition.

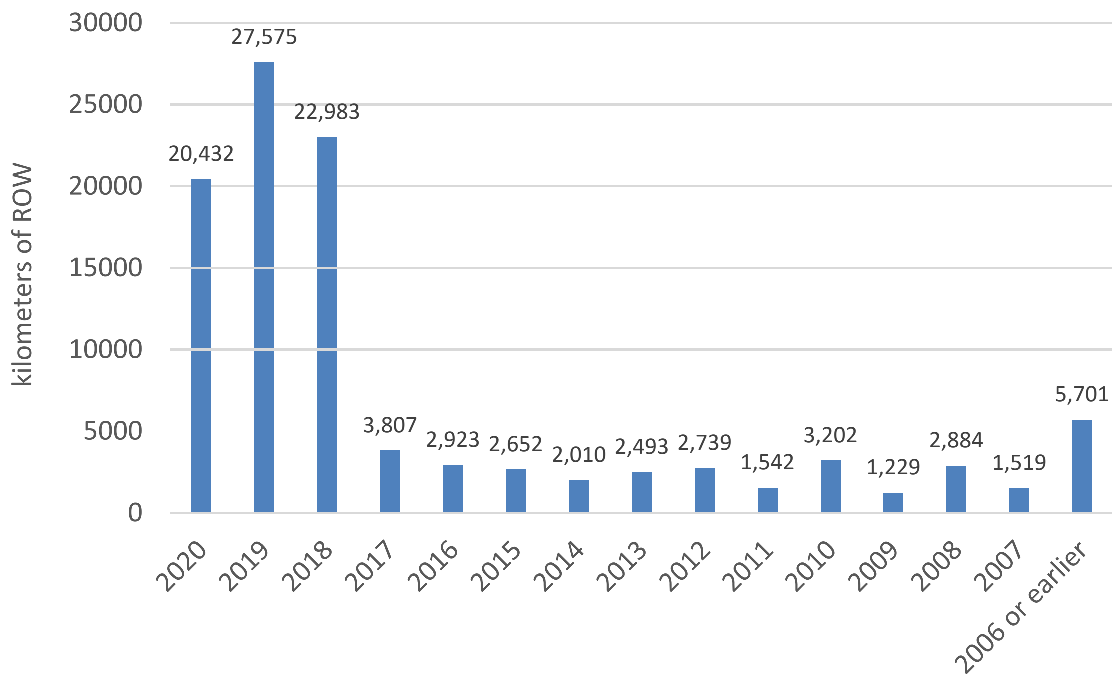


Figure 62: Year of Last Vegetation Treatment

The above chart shows that since the implementation of OCP, Hydro One's ROWs are treated more frequently than under the previous vegetation management strategy. The results include benefits to public safety as defects are addressed more frequently, and improvement in tree caused outages and lower unit costs (see discussion of expert studies regarding OCP performance in DSP Section 3.3). These concepts are discussed further in Exhibit E-03-02.

ASSET CONDITION

Vegetation defects refer to trees and vegetation in close proximity to energized apparatus and trees with strike potential that are observably dead, diseased, decayed, or structurally unsound.

Figure 63: In-Contact Trim on the Left; Hazard Tree Removal on the Right.

As an example, the left side picture in Figure 63 shows a line section with overgrown trees where the branches are in close proximity to the power line. In such a case, the branches must be trimmed back to restore optimal clearance from power lines. The picture on the right shows a dead Maple hazard tree that has a high strike potential for the power line. If such a tree were to fall, the power line could be severely damaged resulting in a customer outage of up to 10 hours depending on the location of the damage. In severe cases, trees of this size can damage adjacent poles and equipment as well. To mitigate this risk, the dead tree in close proximity to the line needs to be removed.

ROW vegetation defects data is collected during Hydro One’s OCP inspections. Defect-based vegetation work prescriptions are then generated for field execution. While the volume of defects will depend on the species of vegetation and the climactic region in which the line is located, it is generally expected that the longer the ROWs have not been cleared the more defects per km and the higher the volume of tree removals that will be required.

The condition of a ROW deteriorates over time as vegetation grows and the health of over-mature, diseased or infected trees adjacent to the ROW gradually declines. When ROW condition deteriorates, it requires more work in the next clearing cycle. Generally, the longer the time elapsed since vegetation management, the higher the vegetation defect backlog on a ROW. The implementation of OCP has significantly increased ROW kms managed every year and reduced the backlog of vegetation defects on Hydro One ROWs. The kms of ROWs managed through the OCP program has increased from 11,753 kms in 2016 (and a 2006-2016 average of 10,890 km annually, which implies a 9.5 year cycle length) to an average of 25,695 kms annually (implying a 4.1 year cycle length) over the 2018-2020 period.

ASSET PERFORMANCE

Hydro One Distribution incurs OM&A expenditures to reduce the likelihood of vegetation caused outages and to manage safety hazards by maintaining clearance between vegetation and energized apparatus. Vegetation related outages account for 39% of SAIDI based on a three year average. The SAIDI and SAIFI contributions attributed to vegetation caused outages are shown in Figures 64 and 65, excluding interruptions during force majeure events.

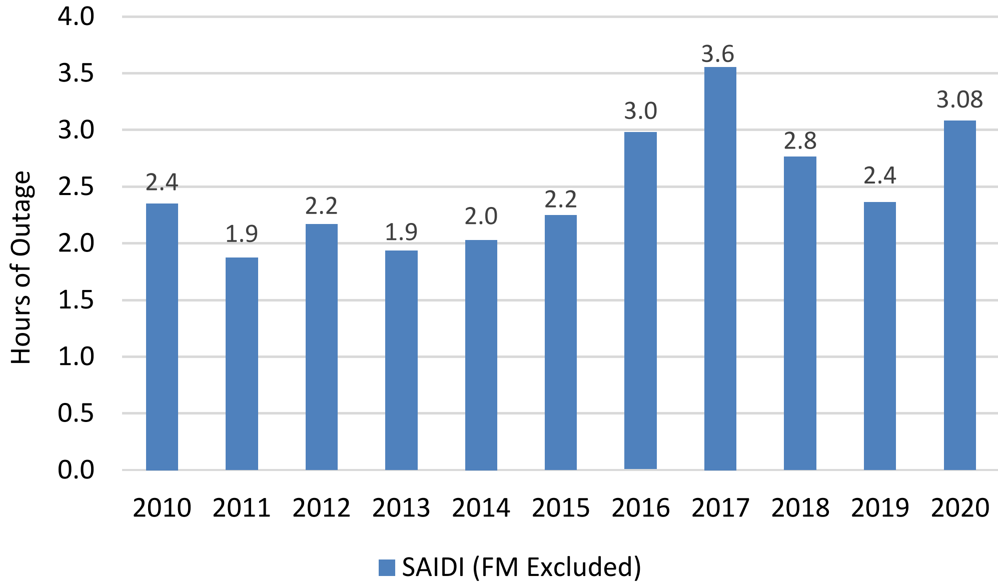


Figure 64: Tree Caused SAIDI Contribution with FM Excluded

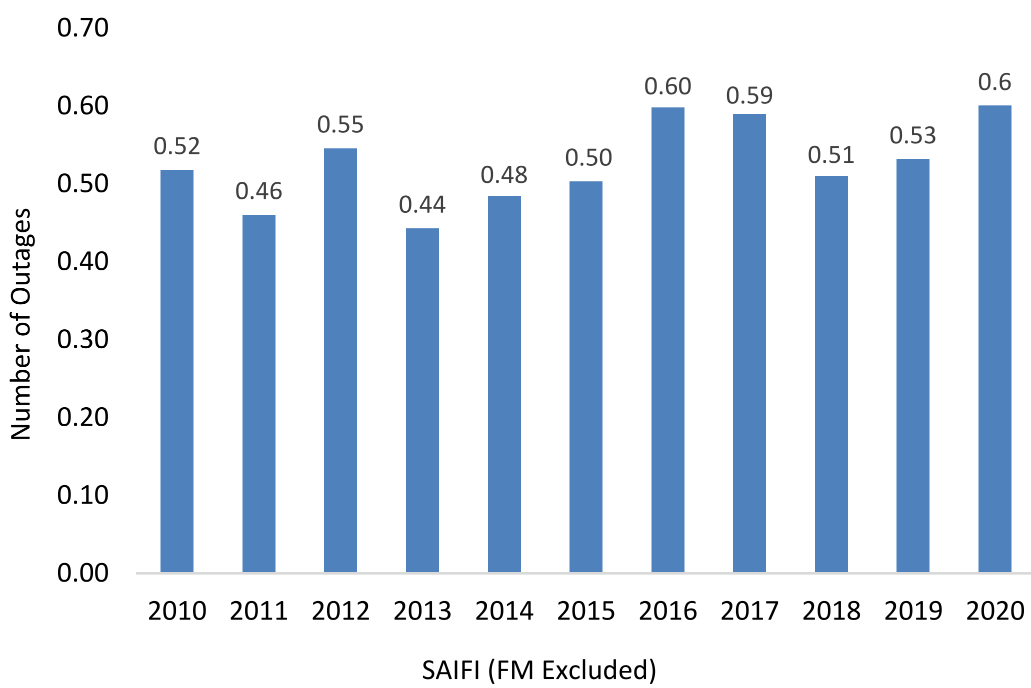


Figure 65: Tree Caused SAIFI Contribution with FM Excluded

Hydro One's non-force majeure SAIDI due to vegetation contacts from 2010 to 2017 shows a worsening trend and the trend was not expected to change without intervention. Based on the recommendation from the *2017 Forestry Assessment* study by Clear Path, Hydro One switched from a corridor-driven vegetation management program to a defect driven program (i.e., OCP). The implementation of OCP has resulted in a 13% improvement in overall system wide reliability from 2017 to 2020. It should also be noted that 2020 was an above average storm year where Hydro One's service territory experienced 41 storm days, excluding force majeure days, compared to an average of 32 storm days annually from 2015 to 2019.

LIFECYCLE STRATEGY

ROW assets are acquired through capital expansion of the distribution network and are managed through the sustainment OM&A budget. ROW maintenance is accomplished through planned and demand investments. Deferring vegetation management activities not only exacerbates the asset risk factors discussed below, but also leads to increased efforts and costs to address vegetation that has grown unchecked for a longer period of time. Failure to address trees that are dead, diseased, infected or structurally unsound in a timely manner results in a higher risk of tree caused outages. According to the above-noted Clear Path report, 90% of such outages were caused by off-ROW trees and branch failures. Removing these trees where possible has a positive impact on reliability. Sustaining the ROW through an effective and sustainable OM&A program is essential to avoiding future escalations in OM&A costs and increased safety and reliability risks.

The ROW kms managed through the OCP program has increased from 11,753 kms in 2016 (which implies a vegetation management cycle length of 9.5 years) to an average of 25,695 kms annually over 2018-2022 (implying a 4.1 year cycle length). Shorter vegetation management cycles result in lower volumes of hazard trees and in-contact vegetation which can impact public safety. The OCP program will be further optimized for each feeder to ensure a sustainable clearing cycle going forward. In addition to the OCP and associated defect correction activities, Hydro One's Public Safety and Reliability Program and Quality Assurance and Quality Control

Program also contribute to the management of vegetation-related risks, as discussed in Exhibit E-03-02.

3.2.4 ASSET COMPONENT INFORMATION – WHOLESALE REVENUE & RETAIL REVENUE METERS

METERS

Hydro One currently owns, operates and maintains two types of revenue meters: (i) wholesale revenue meters; and (ii) retail revenue meters. Wholesale revenue meters are used to settle the purchase of energy where the point of supply is directly connected to the IESO-controlled grid. Retail revenue meters are used to measure energy consumption for retail customers. The primary objective of meter management is to maintain compliance with legal and regulatory metering requirements, including those set out under the *Electricity and Gas Inspection Act*, *Weights and Measures Act*, the OEB's *DSC*, provisions of the Standard Supply Service Code, and IESO Market Rules. Importantly, meters must be managed to enable accurate and reliable customer billing, enhance Hydro One's ability to monitor the distribution system and respond to outages, and support the utility's financial operations.

Wholesale Revenue Metering

Wholesale Revenue Metering Installations (WRMIs) are employed to settle the purchase of energy, and where the point of supply is directly connected to the transmission system, the purchase of transmission services with the IESO. WRMIs can vary in size and complexity depending on the number of meter points in the installation. Major components of a WRMI include two revenue meters (main and alternate), a lockable and sealable meter cabinet, instrument transformers, and secondary cabling. The instrument transformers that provide a metering-related function at each meter point consist of current transformers and potential transformers that step down the current and voltage to a level that is consistent with the requirements of meter and control equipment.

Retail Revenue Metering

Advanced Metering Infrastructure (AMI) for retail revenue metering refers to all of the components (smart meters, repeaters, regional collectors, Head End System, and related software and firmware) that work together as a system to reliably obtain over-the-air meter readings for accurate and reliable Time-of-Use and Two-Tier customer billing in accordance with the OEB's Standard Supply Service Code. AMI can also provide a platform for improving customer service and reducing costs through enabling technology such as outage detection, the provision of customer usage information, tamper detection, and remote disconnect/reconnect capabilities.

Hydro One began the deployment of its first-generation AMI system (known as AMI 1.0) in 2007 in accordance with the direction of the Province of Ontario, which was among the first large-scale AMI deployments in the world. The AMI 1.0 system consists of approximately 1.4 million smart meters across a hybrid network of both "mesh" and "cellular point-to-point" systems. Mesh meters, comprising the overwhelming majority of meters, send data to their respective Head End System through meters, repeaters and collectors. The collectors send data back to Hydro One over cellular networks. Cellular point-to-point meters send data directly to their Head End System through cellular networks.

The AMI 1.0 network covers the vast majority (97%) of Hydro One customers; however there are still gaps in coverage due to a combination of factors including lack of a viable backhaul technology, low customer density where the cost to connect is not economic, and AMI 1.0 technology limitations.[4] Coverage is provided by three distinct AMI vendor systems (Trilliant, Honeywell, and Sensus). The primary Trilliant system serves the overwhelming majority of customers. Through LDC acquisitions, Hydro One also operates a Sensus system (serving customers of the former Norfolk Hydro and Haldimand Hydro service territories), and a

[4] HONI has received a Time-of-Use exemption until 2024 (EB-2019-0259) for approximately 94,000 hard to reach customers.

Honeywell system (serving customers from the former Woodstock Hydro). Figure 66 illustrates AMI 1.0 service territory coverage by vendor.

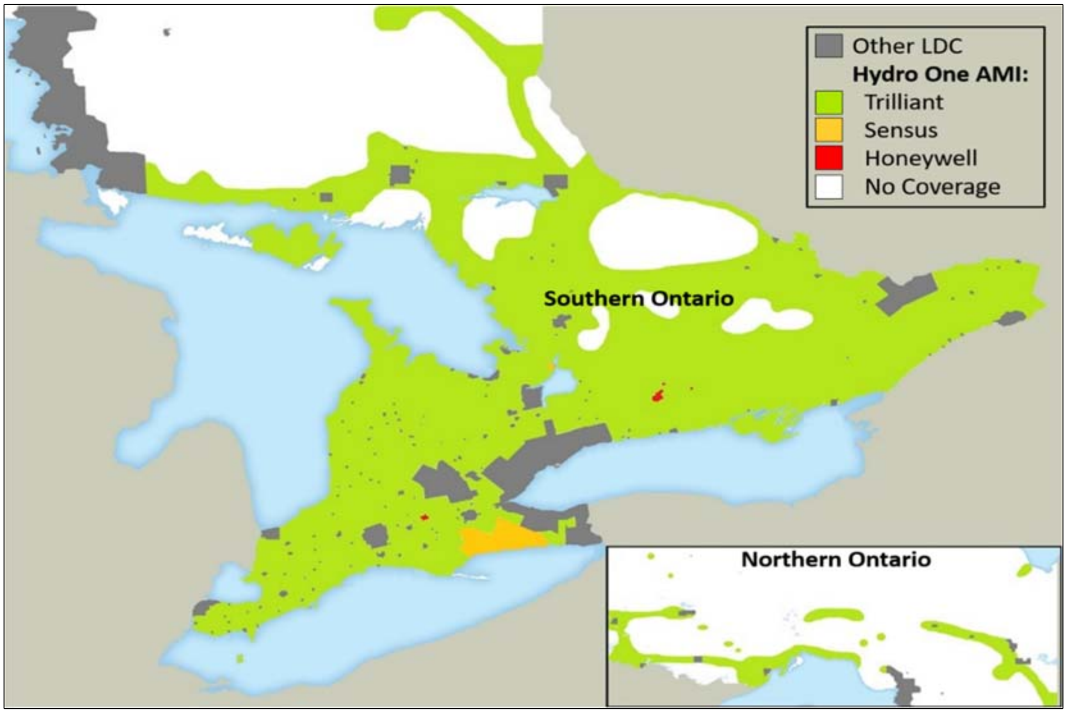


Figure 66: Service Territory AMI 1.0 Network Coverage by System Type

These first-generation AMI systems are not interoperable and operate with their own proprietary meters, communication networks, and IT infrastructure.

DEMOGRAPHICS

Wholesale Revenue Meters

Figure 67 and Table 7 provide an overview of the number of WRMI meters by manufacturer and model. All meters, with the exception of one, are Schneider Electric ION meters. The 8650 is a newer model of the 8600. These models are further differentiated as "C" or "A" series. The C series is typically used as the main meter while the A series is used as the alternate meter. The A series provides additional advanced power quality analysis capability.

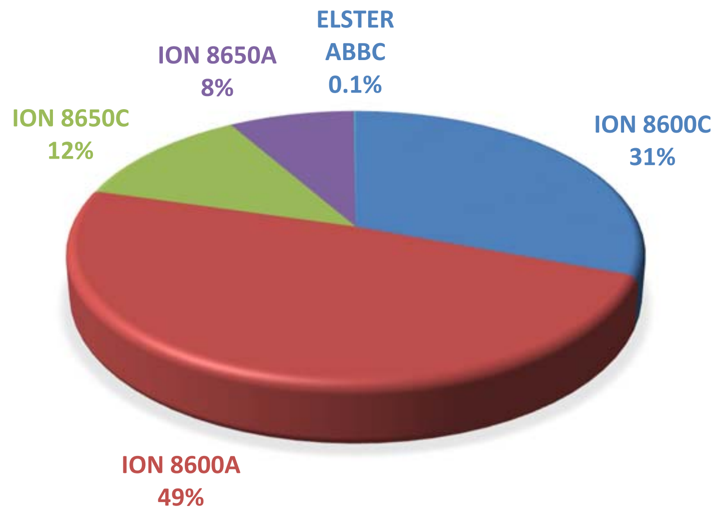


Figure 67: WRMI Meters by Manufacturer Models

Table 7 - WRM Meters by Manufacturer and Model

Model	# Meters	%
ION 8600C	254	31%
ION 8600A	404	49%
ION 8650C	101	12%
ION 8650A	68	8%
ELSTER ABBC	1	0.1%
TOTAL	**828**	**100%**

Instrument Transformers

Instrument transformers are a fundamental component of WRMIs. Figure 68 and Table 8 provide an overview of the number of instrument transformers, which span a wide variety of manufacturers and models due to these assets' long life (60+ years). Sadtem, ABB and Arteche represent a newer category of dry, epoxy encapsulated instrument transformers, representing approximately 60% of the total population. The remaining 40% are a mixture of bushing, bar, and oil filled tank type instrument transformers.

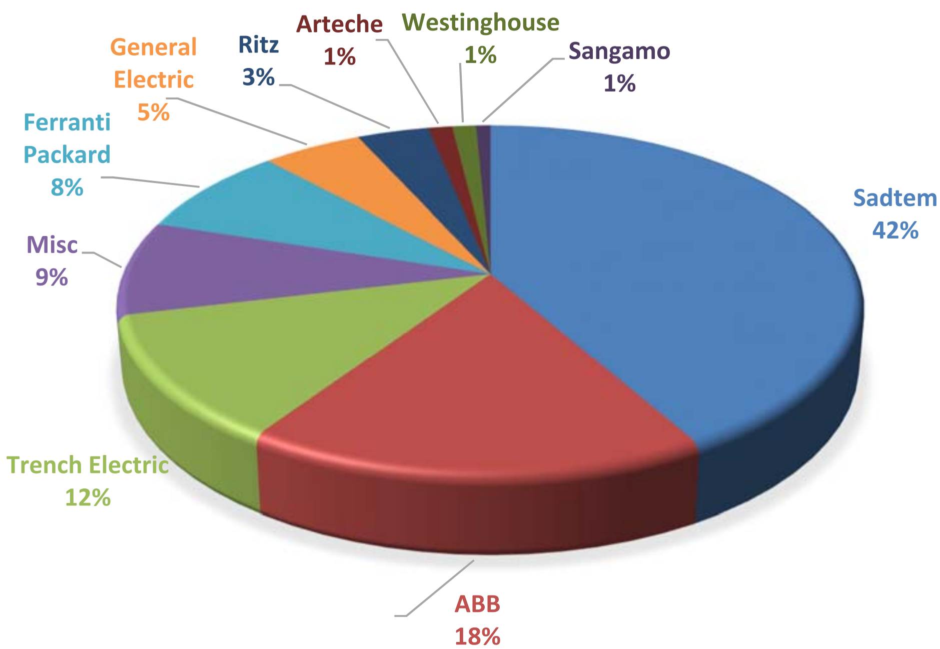


Figure 68: Instrument Transformers by Manufacturer

Table 8 - Instrument Transformers by Manufacturer

Manufacturer	Installations	%
Sadtem	173	42%
ABB	73	18%
Trench Electric	49	12%
Ferranti Packard	34	8%
General Electric	21	5%
Ritz	15	4%
Arteche	5	1%
Westinghouse	5	1%
Sangamo	3	1%
Misc	36	9%
Total	**414**	**100%**

Retail Revenue Meters

Table 9 provides an overview of the number of AMI 1.0 network devices by communication technology. Hydro One owns and operates a population of approximately 1,370,000 meters, 11,000 collectors, and 40,000 repeaters. The overwhelming majority of AMI meters and network devices (95% of meters, and almost 100% of collectors and repeaters) are supplied by Trilliant.

Table 9 - AMI 1.0 Network Devices by Communication Technology (2019)

AMI Network Devices by Technology (2019)						
Meter Communication Technology	**Meters (#)**	**Meters (%)**	**Collectors (#)**	**Collectors (%)**	**Repeaters (#)**	**Repeaters (%)**
Trilliant Mesh	1,300,000	94.83	11,000	99.77	40,000	99.94
Trilliant Cellular P2P	4,000	0.29				
Sensus P2MP	43,000	3.14				
Honeywell Mesh	17,000	1.24	25	0.23	23	0.06
Honeywell Cellular P2P	5,000	0.36				
Ethernet w/modem	1,600	0.12				
Phone Line	100	0.01				
No Communication	150	0.01				
Total Devices	**1,370,850**	**100**	**11,025**	**100**	**40,023**	**100**

CONDITION

The assessment of the condition of modern electronic meters is primarily age-based and measured against manufacturers' recommended service life, in contrast to other types of assets that are primarily assessed based on physical condition. This approach is due to a number of related factors including: (i) the sealed and complex electronic nature of the devices; (ii) the volume and geographic distribution of devices (1.4M meters across Hydro One Distribution's service territory); and (iii) the high cost of individual meter assessment (involving removal, shipping, laboratory testing and assessment, repair if feasible, resealing in accordance with regulatory requirements, and re-shipping). This age-based approach is supported by the analysis of empirical meter failure rates and trends, the identification and analysis of failure root causes, industry benchmarking, and related technical and other studies.

Wholesale Revenue Metering

Figure 69 and Table 10 provide an overview of the age demographics of Hydro One's WRMI meters. Approximately 72% (598 meters) are 10 years of age or less while the remaining 28% (230 meters) are between 11-15 years of age.

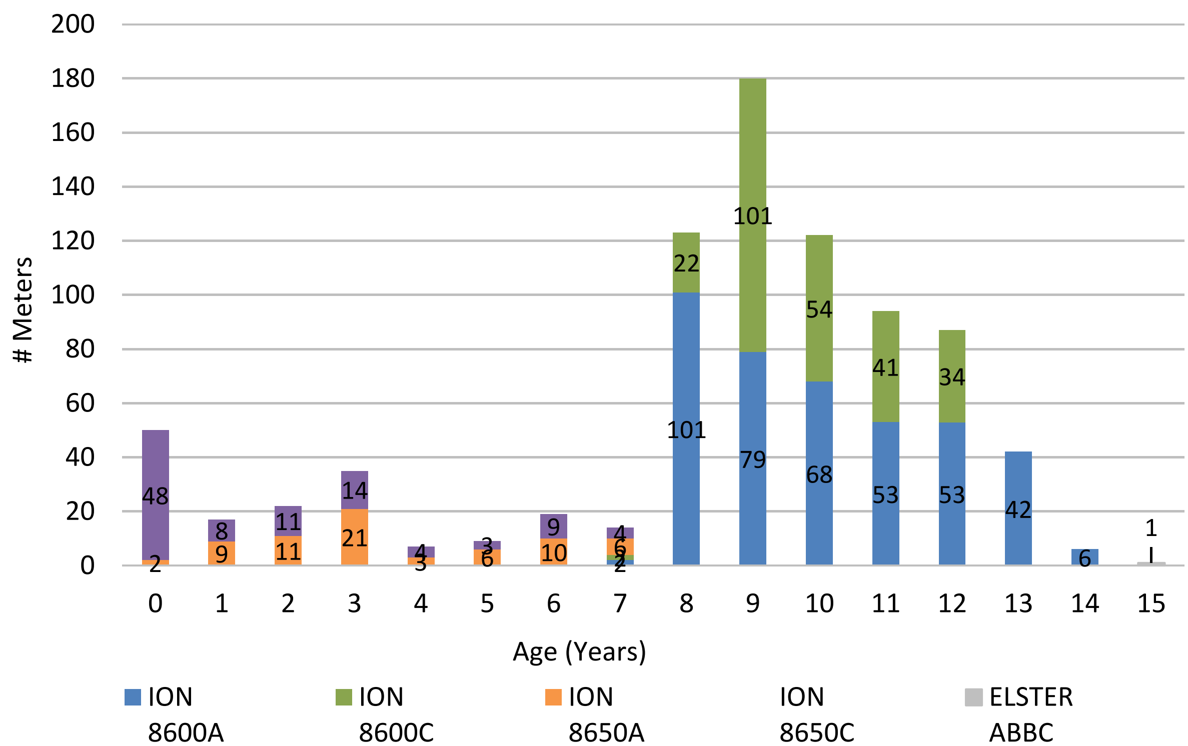


Figure 69: Wholesale Meter Age Distribution

Table 10 - Wholesale Meter Age Distribution

Age (years)	ION 8600C	ION 8600A	ION 8650C	ION 8650A	ELSTER ABBC	TOTAL	%
0			48	2		50	6%
1			8	9		17	2%
2			11	11		22	3%
3			14	21		35	4%
4			4	3		7	1%
5			3	6		9	1%
6			9	10		19	2%
7	2	2	4	6		14	2%
8	22	101				123	15%
9	101	79				180	22%
10	54	68				122	15%
11	41	53				94	11%
12	34	53				87	11%
13		42				42	5%
14		6				6	1%
15					1	1	0%
TOTAL	**254**	**404**	**101**	**68**	**1**	**828**	**100%**

Figure 70 and Table 11 provide an overview of the age demographics of Hydro One's WRMI instrument transformers.

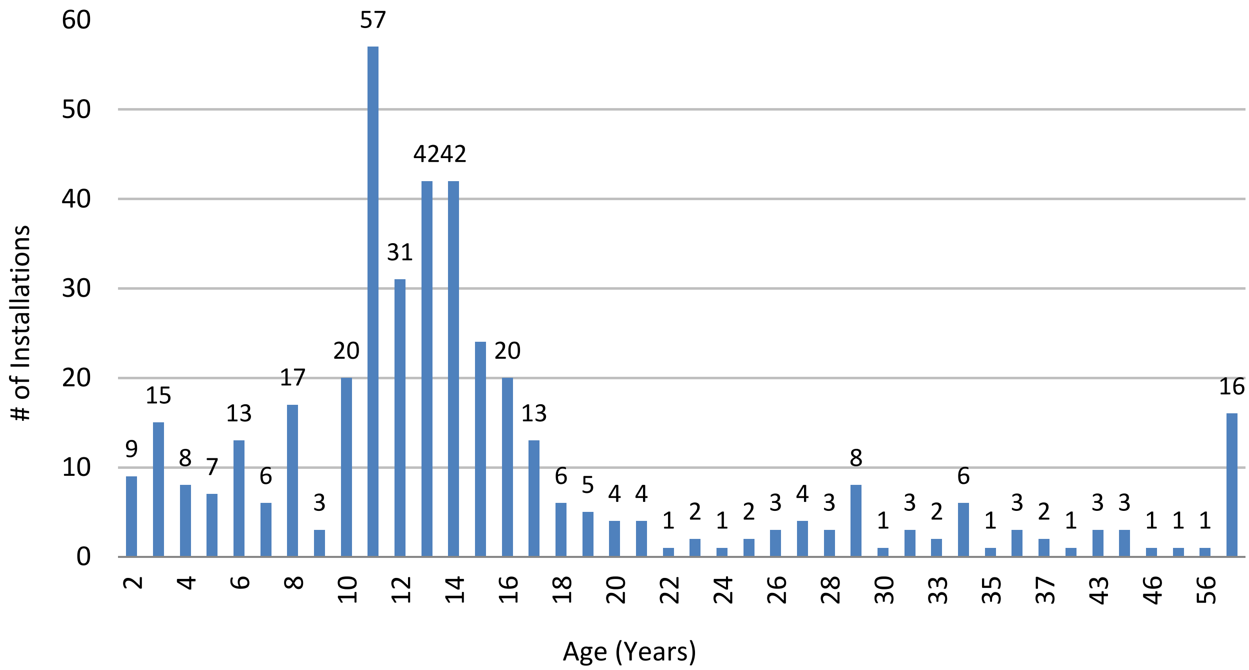


Figure 69: WRMI Instrument Transformer Age Profile

Table 11 - WRM Instrument Transformer Age Profile

Age Group	#	Percentage
0 – 10 years	98	23.7%
11 – 20 years	244	58.9%
21 – 30 years	29	7.0%
31 – 40 years	17	4.1%
41 – 45 years	7	1.7%
46 – 50 years	2	0.5%
51 – 55 years	0	0.0%
56 – 60 years	17	4.1%
Totals	**414**	**100%**

Criticality of Instrument Transformers

The majority of WRMI instrument transformers are located inside transformer stations on either the bus structure or inside metal clad equipment. Although the probability is low, there is a risk that an instrument transformer may fail catastrophically which can result in a station outage and loss of customer load. In this regard, station outage loss risk is minimized and managed in accordance with the IESO's Market Rules related to the Emergency Instrument Transformer Restoration Plan.

Trends and Impacts of Instrument Transformer Failures

Compared to meters that are typically reliable and easily sourced, instrument transformer failures pose a higher impact in terms of power system reliability and timely restoration. There are two trends of concern in this regard: (i) ABB instrument transformer failures; and (ii) instrument transformers approaching end of service life, as discussed below.

Figure 70 and Table 12 provide the total incidence of instrument transformer failures between 2015 and 2020. There has been a trend of increasing ABB instrument transformer failures with eight ABB WRMIs failing in 2020 alone.

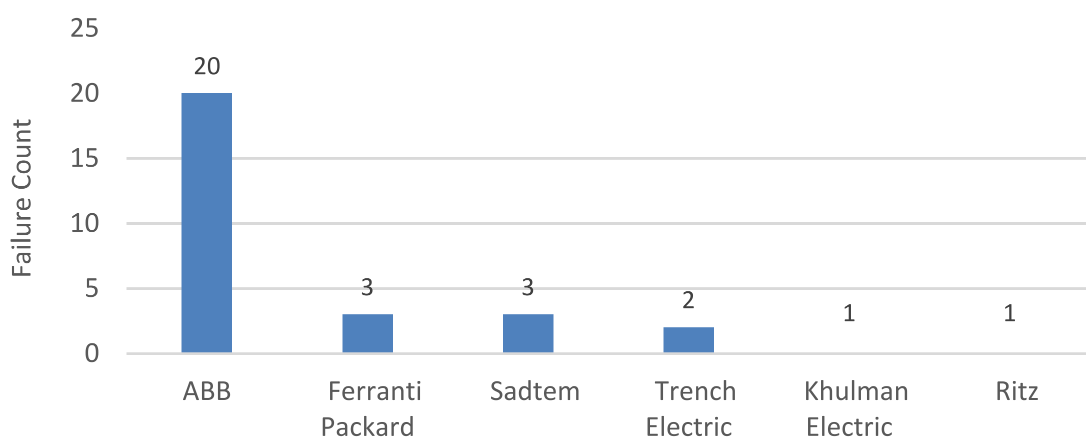


Figure 70: Instrument Transformer Failures by Manufacturer: 2015-2020

Table 12 – Instrument Transformer Failures by Manufacturer

Failures by Make	Installations (#)	% of Total Failures	Ave Age @ Failure (Yrs)
ABB	20	67%	13.4
Ferranti Packard	3	10%	60.0
Sadtem	3	10%	13.3
Trench Electric	2	7%	15.5
Khulman Electric	1	3%	19.0
Ritz	1	3%	13.0

The age profile of instrument transformers at the time of failure is illustrated in Figure 71 below.

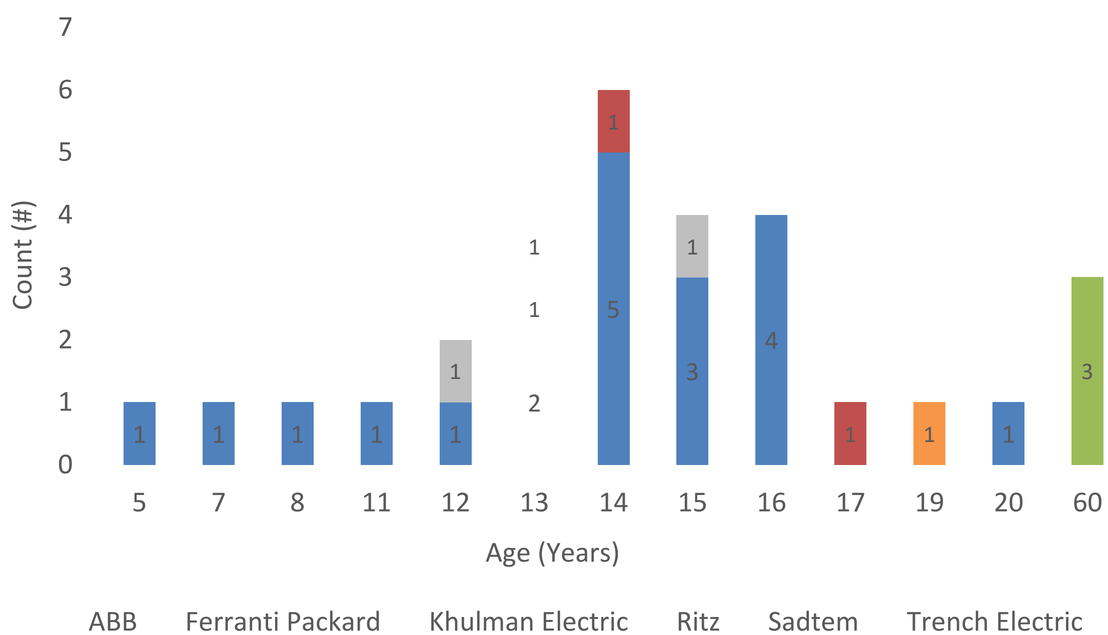


Figure 71: Number of Instrument Transformer Failures at Age of Failure

The ABB models contributing to these failures are current transformer models KOR, and voltage transformer models VOZ and VOY. The greatest portion of failures occurred with 20 installations failing at an average age of 13.4 years. As an example, Figure 72 below provides photographs of certain failed instrument transformers.

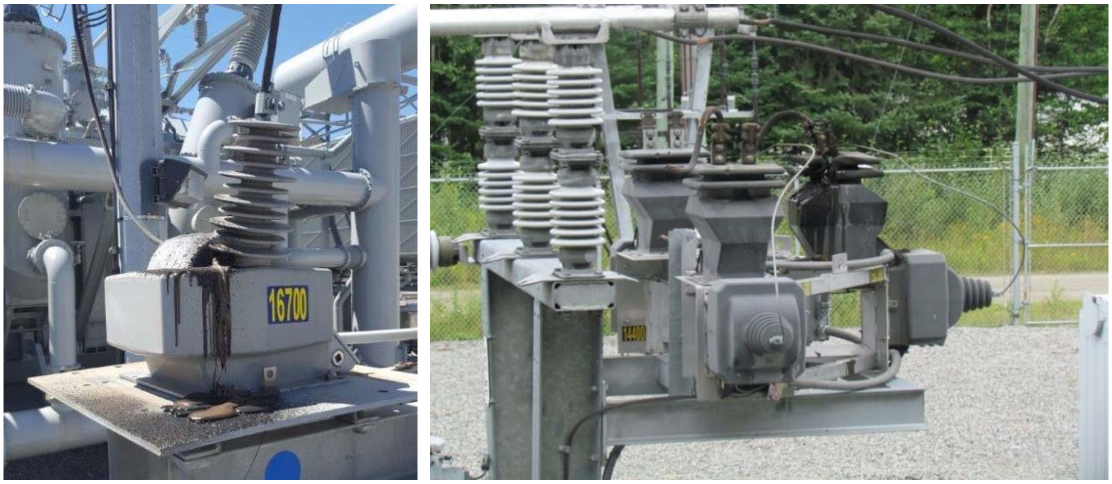


Figure 72: Failed Instrument Transformers

There are a total 65 WRMIs employing these ABB instrument transformer models. Hydro One plans to proactively replace these problematic models to reduce reliability risk and minimize costly and urgent corrective maintenance associated with a run-to-failure approach. Hydro One plans to replace these specific models that are older than 10 years (49 installations) within the 2023 to 2027 period.

In addition to the ABB instrument transformers, there is also an increasing risk of failure associated with instrument transformers over 60 years of age. Manufacturer ESL data is not available for instrument transformers older than 30 years. Over the 2015-2020 period, 3 (15%) of Hydro One's 20 WRMI instrument transformers that are over 60 years old have failed and required full upgrades. Based on this failure rate and the age of the devices, Hydro One believes their risk of failure is increasing and will closely monitor their performance.

Retail Revenue Meters

Meter age and meter failures are key indicators of the health of the retail revenue meter population. Figure 73 below provides the age distribution of meters by year and vendor for the meter population. Approximately 840,000 meters (approximately 65% of the meter population) are between 11-13 years old and will begin to reach the end of their 15-year service life in 2022.

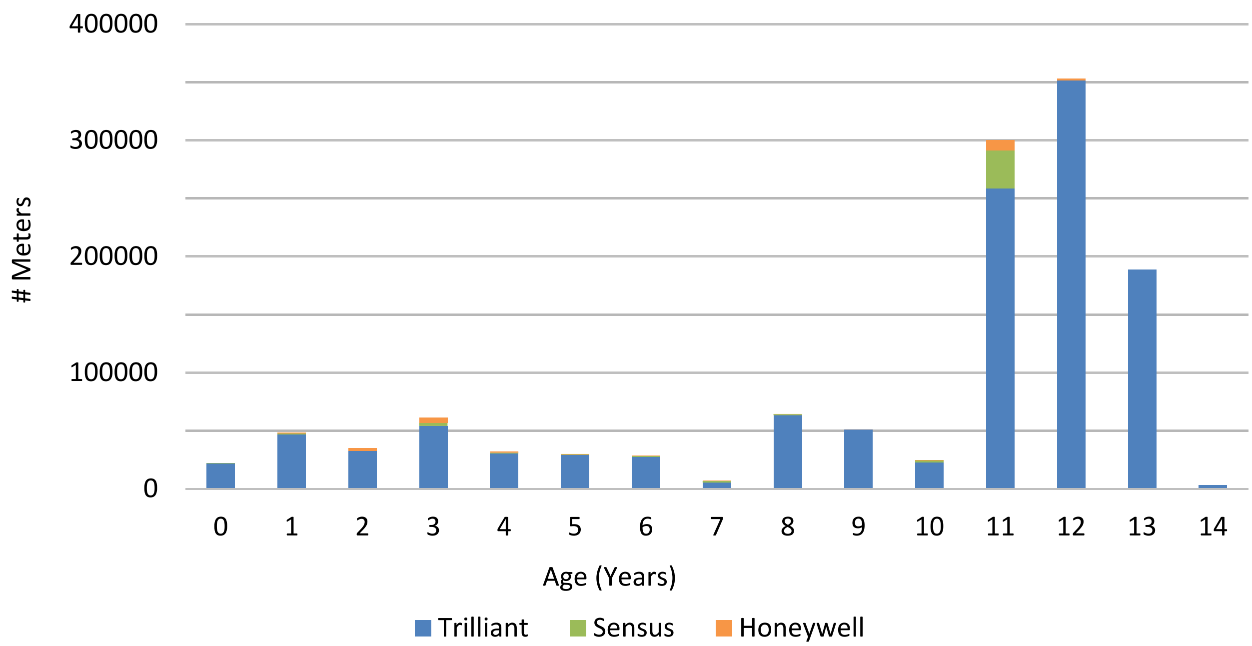


Figure 73: Meter Age Distribution by Year/Vendor (as of 2020)

Figure 74 presents the annual volume of Trilliant L+G ALF meter failures for the period 2017-2020.[5] Meter failures have almost doubled over this period, with approximately 22,500 meters (1.8% of the total meter population) failing in 2020.

[5] Meter failure data began to be reliably collected in 2017.

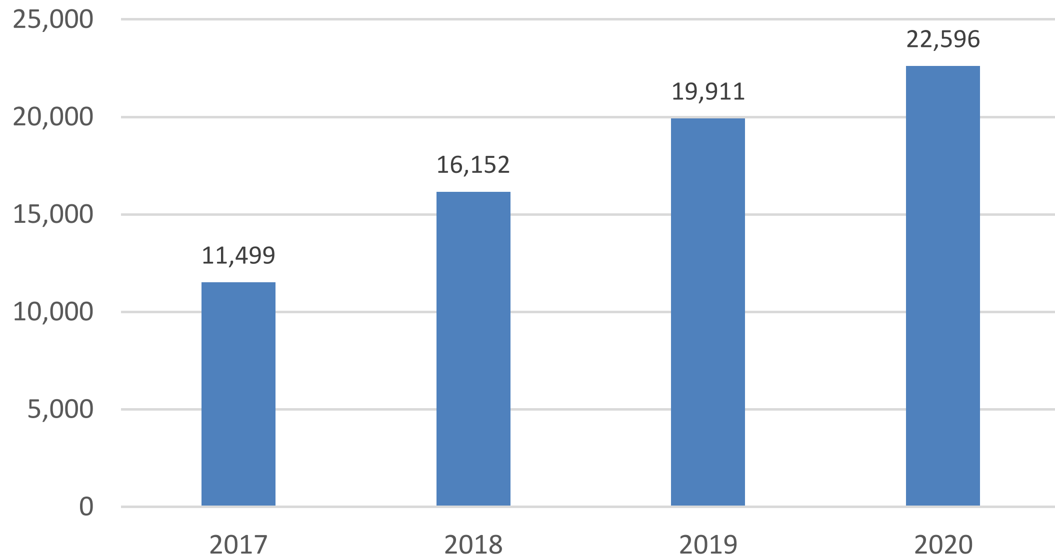


Figure 74: Trilliant Residential Meter Failures: 2017-2020 (L&G ALF Meter)

Figure 75 below illustrates the failure rates of meters by age for the meter population. The figure shows that older meters fail at a greater rate than newer meters, with the oldest population of meters (13 to 14 years old) failing at a rate of 4% and 6% per year respectively.

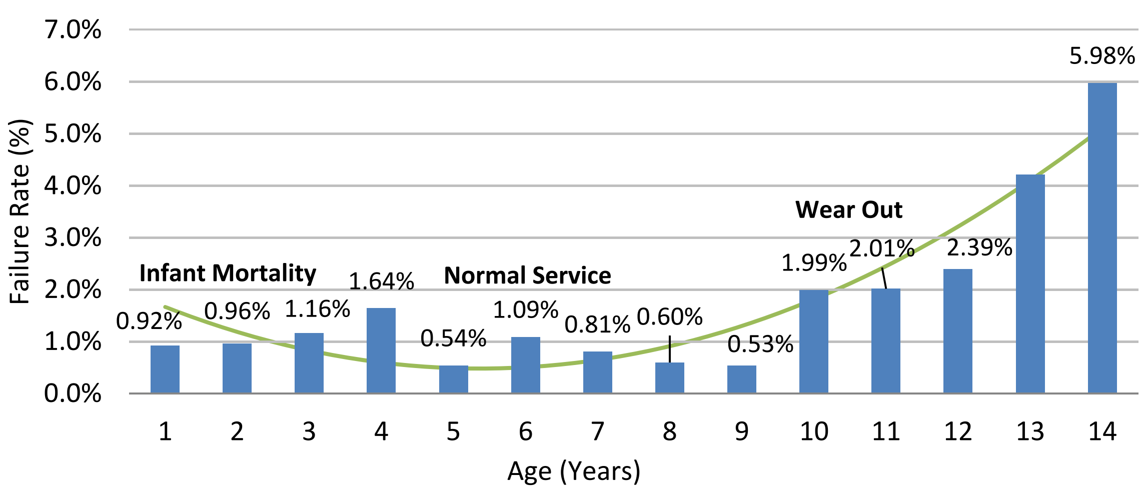


Figure 75: Meter Failure Rate by Age of Meter (as of 2020)

The polynomial trend line applied to the meter failure rates exhibits a classic product lifecycle "bathtub curve", a common engineering term describing a product's failure characteristics over its service life, comprising three discrete periods:

- An infant mortality period in the early years with a decreasing failure rate;
- A normal life period with a low, relatively constant failure rate; and
- A wear out period exhibiting increased failures as the population reaches end of service life.

Notably, the trend line indicates older meters are entering their wear out period with increasing failure rates.

Hydro Quebec performed an Accelerated Life Testing (ALT) study for Hydro One (see DSP Section 3.3) to better understand meter failure mechanisms. ALT is the process of testing samples from a meter population and subjecting them to stressors that simulate the service life by reducing time-to-failure without introducing any new failure mechanisms. By analyzing the meter's response to such tests, predictions can be made with confidence levels on meter service life. The study included accuracy tests, communication tests, load profile and register verification, Liquid Crystal Display (LCD) discolouration measurement, super capacitor characterization, and electronic circuit analysis. The study found multiple issues causing the meters to fail including:

- Electrolyte leakage from capacitors preventing meters to communicate;
- Transformer failures cutting power supply to the meter;
- LCD component failures resulting in corrupted displays or no display at all; and
- Cracked solder joints connecting the metrology board to the communication board impacting meter communication.

Figures 76, 77, and 78 provide illustrative examples of meters in deteriorated condition and associated failure modes.

Figure 76: Capacitor Electrolyte Leakage

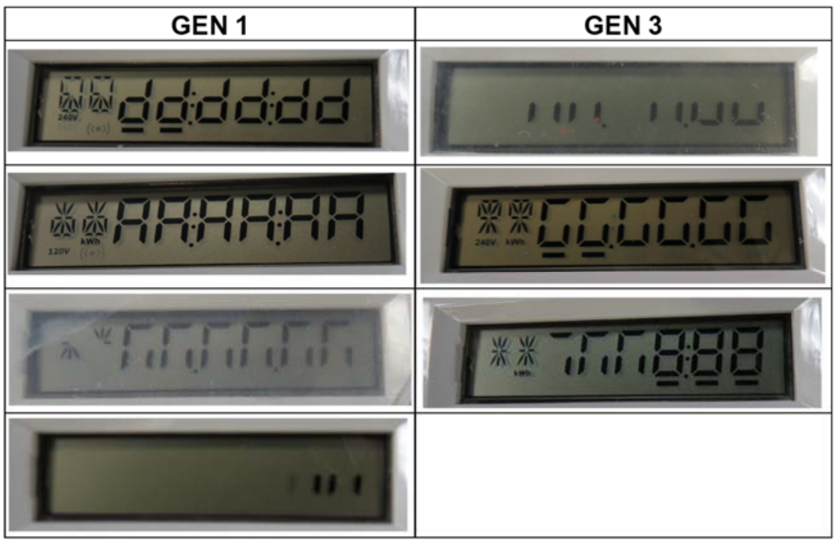


Figure 77: Meter LCD Failures

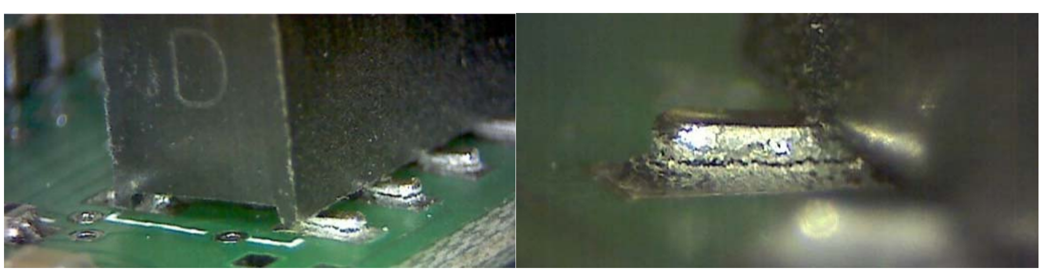


Figure 78: Cracked Solder Joints

It should be noted that meters with faulty indicating displays, as illustrated above, are not normally considered compliant with a utility's "good repair" obligations for meters under the *Electricity Gas and Inspection Act* as they are unable to be read manually by field personnel or customers. Although Hydro One has received a temporary regulatory exemption for meters with faulty displays manufactured between 2008 and 2011 to extend their service lives, Measurement Canada has directed Hydro One to immediately replace meters with faulty displays when found in-service.[6]

Technological Obsolescence Considerations

Unlike traditional electromechanical meters, AMI systems are complex and subject to both physical mortality (discussed above) and technological obsolescence factors. The Ontario Auditor General, in its report on Ontario's smart meter initiative, found a 15-year service life estimate for meters is likely overly optimistic given technological obsolescence considerations.[7] AMI systems, in general, are subject to significant technological changes and are similar to other types of information technology requiring significant upgrades or more frequent replacement as the technology matures. However, unlike other forms of information technology, making physical updates to already installed meters is more challenging given the number of devices and their geographic distribution across an expansive service territory.

Hydro One is experiencing multiple conditions of technological obsolescence with its first generation AMI 1.0 system driving operational challenges and costs including:

- Short notice product de-listings and the related effort to qualify replacement products;
- Reduced vendor support for older technology and unavailability of original parts;
- The modernization of third party technology (e.g., the upgrade from CDMA to LTE by cellular service providers) rendering first generation AMI 1.0 equipment incompatible; and
- Lost opportunities for potential cost effective customer and operational benefits associated with advancements in technology since 2007 (e.g., improved network reliability and customer coverage, enhanced meter memory, cost-effective remote disconnect/reconnect functionality, etc.).

[6] Exemption Letter from Measurement Canada: Deficient Indicating Display on L+G Focus Meters (MC NOA AE-1559), May 18, 2016. Guy Dacquay, Manager, Utility Metering Division, Measurement Canada.
[7] 2014 Annual Report of the Auditor General of Ontario, 2014, pg. 391

Trends and Impacts of AMI 1.0 Failures

AMI 1.0 meters will begin to reach the end of their 15-year service life in 2022. Since 2017, meter failures have close to doubled from 11,500 in 2017 to 22,500 in 2020. As meters age, they have begun to fail at an increasing rate, indicating that meters have reached the wear out period in their product lifecycle. Significantly, meter failure projections based on the independent ALT Study (see DSP Section 3.3 and DSP Section 3.11, D-SR-12) estimate that approximately 579,000 meters will by the end of 2027. Increasing meter failures beyond normal operating levels pose impacts and critical risks to Hydro One, including:

- Reduced billing reliability and customer dissatisfaction from estimated billing and bill corrections;
- Increasing field work and associated costs as a result of unplanned individual meter replacements and unscheduled manual meter reading;
- Higher labour costs for individual meter replacements relative to peers and relative to mass meter replacements (see DSP Section 3.3);
- Higher meter costs relative to peers and relative to bulk purchases of meters associated with mass meter deployments (see DSP Section 3.3) ;
- Reactive replacement of individual failed meters with obsolete technology;
- The testing and resealing of over 90% of the meter population that will have reached the end of their service life by the end of 2027, and the associated risk of needing to replace failed samples with more expensive obsolete technology;
- Lost opportunities for customer service and operational benefits associated with up-to-date technology; and
- Non-compliance with Federal and Provincial regulatory requirements.

PERFORMANCE

Wholesale Revenue Meter

The performance of WRMIs is measured primarily by “Successful Daily Meter Communication”, which is a function of the communication network performance, equipment failures (instrument transformers and meters), and the ability to replace this equipment in a timely manner. In 2020, Hydro One achieved average successful daily meter communication of 98% versus a target of 95%. As WRMI components age, this performance measure will be closely monitored.

Retail Revenue Meters

The performance of the AMI 1.0 system is measured primarily by billing accuracy as defined in the OEB Distribution System Code.[8] Billing accuracy is a function of the general performance of the AMI network overall, the number of individual meter failures, and the ability to replace meters and/or perform unscheduled manual meter reading in time to avoid an estimated bill. Without significant intervention, meter failures will continue to increase as discussed above, and the associated volume of field work in replacing individual meters and unscheduled manual meter reading will also continue to increase, leading to a higher risk of inaccurate bills. In the 2017-2019 period, field work associated with meter issues increased by 47% (23,383 to 34,274 field visits) with an approximately $1M increase in costs.

LIFECYCLE STRATEGY

Wholesale Revenue Meters

Hydro One's WRMI replacement strategy has historically been run to failure. This strategy has had minimal impact on customer load as WRMI failures in the majority of cases have not resulted in customer load interruption. Typically, one component of the WRMI fails (either a meter which has backup or one of the 6 instrument transformers), allowing the WRMI to continue to operate (although with reduced accuracy where the instrument transformer failed) while corrective maintenance or full installation replacement plans are executed. In the event of total WRMI failure, revenue metering data is managed by:

- Installing temporary metering;
- Executing the Emergency Instrument Transformer Restoration Plan pursuant to IESO Market Rules requiring the failed WRMI to be remediated within a 12 week period; and

[8] Ontario Distribution System Code, Section 7.11, March 1, 2020

- Transferring the customer load to an alternate transformer/bus/feeder. WRMIs are typically within DESN transformer stations where in the event of load interruption, the load is transferred to the other transformer/bus/feeder which has been sized to accommodate the full load of both transformers for a temporary period.

Retail Revenue Meters

Hydro One, similar to other utilities and asset types, employs different maintenance strategies for retail revenue meters depending on the stage in the asset's lifecycle.

Normal Service Life

Shortly after AMI installation and a period of stabilization, the AMI network enters a period of a consistent performance (i.e., normal service life). In the normal service life stage, a cost-effective, low customer impact, run to failure approach is employed where individual failed meters are replaced like for like with functioning meters. Meters are replaced rather than repaired because the cost of repair (involving removal, shipping, lab assessing and diagnostics, repairing if feasible, resealing, and re-shipping back to the field) is higher than replacement.

End-of-Service Life

In the end-of-service life stage, as meter digital components begin to deteriorate due to age and environmental conditions, and individual meter failures, individual meter replacement costs, and associated risks begin to increase, the need for mass meter replacements is assessed. This assessment is based on a combination of factors including manufacturer service life information, empirical failure trends and root causes, independent testing, and best industry practices from benchmarking and other sources. All of these inputs, discussed below, allow for the best correlation between age of device, risk of failure, and future costs.

Meter 15-Year Service Life

Hydro One's primary meter vendor, Trilliant, has attested that it designs its products to operate for a minimum period of 15 years. Independent laboratory analysis by Trilliant of its SecureMesh radio, the key meter component that enables it to reliably communicate, supports a minimum

ESL of 15-years. However, Trilliant does not guarantee a minimum 15-year meter service life and states that actual meter performance may differ materially from minimum service life. It recommends a conservative approach to replacing metering equipment with a meter replacement cycle that supports up to and including the 15th year of service to balance maximum service life and security of service.[9]

AMI Benchmarking (see DSP Section 3.3) and other industry studies also support an approximately 15-year service life for first generation AMI meters. The AMI Benchmarking Study (involving comparisons against 36 Canadian and U.S. utilities) found that Hydro One was among 44% of respondents with an expected meter service life of 15-years and that the 15-year service life represented the mode of the respondent group. An OEB commissioned Asset Depreciation Study prepared by Kinectrics Inc. found that the appropriate service lives for smart meters is in the range of 5-15 years.[10] The Ontario Auditor General, in its report on Ontario's smart meter initiative discussed previously, also found that the estimated useful life for a typical first generation smart meter was 15 years.[11]

In order to verify vendor meter service life attestations, confirm industry benchmarking data, corroborate information from other sources, and better understand root causes, Hydro One engaged Hydro Quebec to independently design and perform an ALT study, as noted above.. the ALT study found critical failure modes involving the rapid degradation of the capacitor that enables GEN 1 meters to reliably communicate (GEN 1 meters were the vendor's initial meter design deployed in the 2007-2009 period totalling approximately 661,000 meters). Meter failure projections, based on ALT study results and recommended confidence levels, estimate approximately 579,000 meter failures by the end of 2027. Most significantly, the ALT study findings of accelerating meter failures align with information from vendor, benchmarking, and

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[9] DSP Section 3.3 Attachment 4, Correspondence from Stephen Lupo, Senior VP Trilliant on Meter Expected Service Life (November 29, 2019).
[10] Asset Depreciation Study for the Ontario Energy Board, Kinectrics Inc. Report No K-418033-RA-001-R000, July 8, 2010.
[11] 2014 Annual Report of the Auditor General of Ontario, 2014, pg. 391

other industry studies supporting an approximately 15-year service life (or less) for Hydro One's AMI 1.0 meters. The study, "Accelerated Life Testing of Focus ALF meters with GEN 1 and GEN 3 Communications Boards, September 2020" is provided in DSP Section 3.3 and discussed in detail in DSP Section 3.11, D-SR-12.

Given vendor attestations of meter service life, meter failure rates and trends, industry benchmarking and other studies, independent ALT study results, and technological obsolescence considerations, Hydro One considers it prudent to plan AMI investments based on an approximately 15-year service life for its AMI 1.0 system. Hydro One's plan to replace the legacy AMI 1.0 system with a new AMI 2.0 system is presented in DSP Section 3.11, D-SR-12.

INSPECTION & MAINTENANCE PRACTICES

Wholesale Revenue Meters

WRMI capital corrective and preventative maintenance programs are employed to ensure compliance with applicable legal and regulatory requirements. The decision to perform corrective maintenance or replacement is dependent on IESO Market Rules, failure trends, age, and repair costs.

Meter Accuracy Verification

The federal *Electricity and Gas Inspection Act* requires meters to be tested for accuracy on a pre-determined schedule (at typically the 10 year, 18 year, and 24 year marks). Based on test results, meters are either resealed and placed back into service or removed from service.

Corrective Maintenance

Corrective maintenance is conducted in accordance with IESO Market Rules. As an example, where one of six instrument transformers fail in a WRMI governed by the IESO's Alternative Metering Installation Standard (i.e., installations not meeting full requirements at market opening), a single instrument transformer replacement is required. Where more than one instrument transformers fail in a WRMI, the entire installation must be brought to full compliance which typically results in the replacement of all six instrument transformers.

Preventive Maintenance

WRMI preventative maintenance is comprised of:

- Annually inspecting WRMIs for rust, corrosion, physical damage of components, loose and damaged connections, and indications of burning or discoloration indicating overheating;
- Confirming the current transformer ratio every six years; and
- Replacing seal expired meters.

Retail Revenue Meters

The federal *Electricity and Gas Inspection Act* requires all meters to be verified through a sampling program at specified intervals in order to ensure a customer's electricity usage is metered accurately. Once a meter seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended (through compliance testing), or be replaced. Figure 79 below provides an overview of AMI 1.0 meter seal expiries by year.

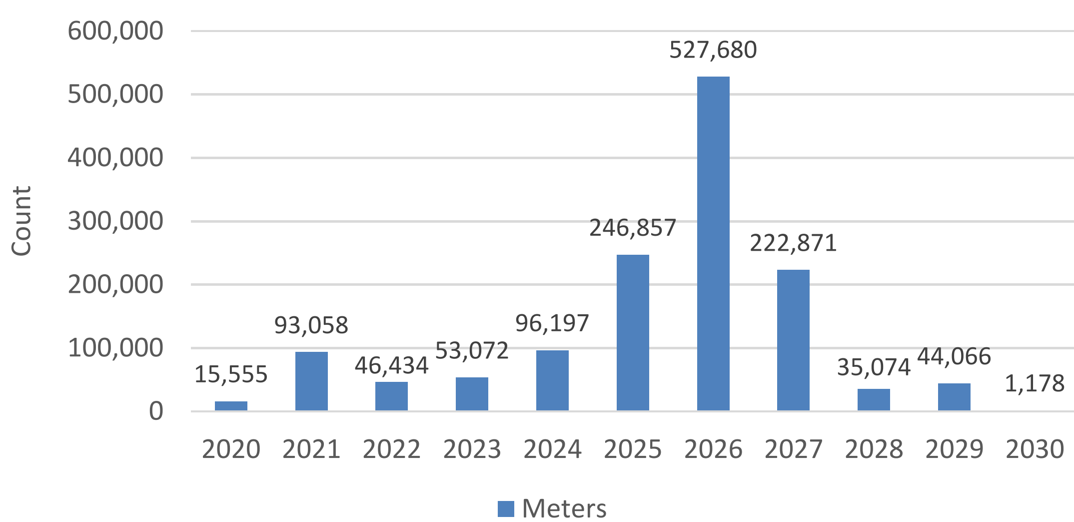

Figure 79: AMI 1.0 Meter Seal Expiries by Year

Approximately 1,250,000 meters, or 92% of the total meter population, will have their seals expire between 2023 and 2027. As a result, sample testing and resealing of over 90% of the meter population would need to be conducted on meters that will have significantly exceeded their 15-year service life. This poses the risk of needing to replace meters with expensive obsolete technology should a sample fail.

REPLACEMENT & REFURBISHMENT

Wholesale Revenue Meters

The approach to WRMI replacement varies based on WRMI component. Meters are replaced as a result of an expired seal that fails accuracy testing, a failed meter, or technological obsolescence (e.g., incompatibility with third party telecom upgrades). Instrument transformers are replaced if they are unable to be economically repaired or a condition assessment indicates imminent failure (e.g. corroding oil tank).

The refurbishment of WRMI components is executed via the corrective maintenance program where it is cost effective.

Retail Revenue Meters

The AMI meter replacement approach (individual replacement vs. mass replacement) is dependent on the assets' lifecycle stage (normal service life and end-of-service life) as discussed above under "Lifecycle Strategy".

The continued refurbishment/repair of AMI 1.0 meters is not feasible or cost effective given a variety of considerations, including: (i) the volume and geographic distribution of individual meters (over 1.4M devices distributed across 90% of the Province of Ontario); and (ii) the high costs of refurbishment (shipping, lab assessing and diagnostics, repairing if feasible, resealing, and re-shipping back to the field) relative to the cost of a new meter.

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SECTION 3.3 – DSP – BENCHMARKING AND OTHER STUDIES

Benchmarking can provide valuable insights into a utility's performance, especially when used in combination with specific cost drivers and other sources of utility performance information to enable a meaningful overall assessment from an industry lens. Where applicable, the studies also allow Hydro One to assess the work practices that underpin its accomplishments as well as to better understand relevant industry standards/best practices.

In the Decision in Hydro One's last Distribution Rate Application (EB-2017-0049), dated March 7, 2019, page 35, the OEB found that Hydro One had taken a "positive step forward" with respect to benchmarking for key programs. For the subsequent rebasing application, the OEB directed Hydro One Distribution to continue with its benchmarking and expand it to include other capital programs and administration functions and to state how the results of studies have been reflected in the program plans. Further, the OEB required Hydro One to "file information in its next rebasing application for vegetation management, pole replacement, station refurbishment and IT, reporting on the extent to which the projected outcomes from each of the benchmarking studies considered in this application have been realized" (page 36 of the Decision in the last Distribution Rate Application).

Hydro One has responded to the OEB's direction by continuing with and expanding upon various benchmarking studies to gauge and inform a number of key functions and program plans. These studies presented Hydro One with the opportunity to assess and pursue continuous improvement based on comparison against its own past performance or the performance of industry comparators. Notably, in addition to studies related to distribution poles/stations and vegetation management, advanced metering infrastructure (AMI) end-of-life testing and replacement cost benchmarking were included in the suite of studies to evaluate the meter life assumptions, work practices and costs associated with this important work program. More specifically, this exhibit presents the following studies:

Programs benchmarked in last distribution application:[1]

1. Pole Replacement Program Study - Guidehouse (formerly Navigant) and First Quartile
2. Station Refurbishment Program Study - Guidehouse and First Quartile
3. Vegetation Management Program - CN Utility
4. Optimal Cycle Protocol - ClearPath

New studies undertaken to expand benchmarking:

5. AMI Replacement Costs Benchmarking - Guidehouse and First Quartile
6. Accelerated Life Testing of Meters - Hydro Quebec
7. Billing and Call Center Costs Benchmarking - Information Services Group (ISG)
8. Smart Meter Efficiency Report

Additional third party and internal studies correspond to other aspects of the Application are discussed elsewhere, as indicated below:

- The Total Factor Productivity Study and Econometric Total Cost Benchmarking Study is discussed in Exhibit A-04-01;
- Review of the Productivity Framework is discussed in SPF Section 1.4;
- First Nations Reliability Report 2021 - Report on Initiatives to address reliability challenges in First Nations, and northern communities (Internal Report) is discussed in Exhibit A-07-02, Attachment 1;
- Report on the Execution of the DX Capital Program Relative to Plan (Internal Report) is discussed in DSP Section 3.9, Attachment 2;
- Benchmarking of Corporate Costs & Administrative Functions is discussed in Exhibit E-04-02;
- The Comparison of Common Corporate Costs Capitalization with Utilities in Ontario, Canada and USA is discussed in Exhibit E-04-08; and
- The Total Compensation Cost Benchmarking Study is discussed in Exhibit E-06-01.

[1] The IT benchmarking study is presented in GSP Section 4.3.

3.3.1 POLE REPLACEMENT PROGRAM STUDY - GUIDEHOUSE & FIRST QUARTILE

3.3.1.1 STUDY OVERVIEW

The consortium of Guidehouse and First Quartile completed a study (which also covered station refurbishment, as discussed in Section 3.3.2 below) to quantify and evaluate the unit costs of Hydro One's distribution pole replacements through benchmarking comparison and analysis against a group of comparator utilities. In addition to cost data, data collected in relation to demographics and work practices helped to inform a proper understanding of the cost performance results in light of the utility's unique operating context. As detailed below, the study concluded, among other things, that Hydro One's distribution poles are on average older than the comparator group and replacement costs are comparable to the mean of the comparator group.

3.3.1.2 STUDY RESULTS

The key findings of the Pole Replacement Program Study are set out in Table 1 below. A copy of the report is provided as Attachment 1 to this Section 3.3.

Table 1 - Pole Replacement Program Study - Key Findings

#	Key Study Finding	Study Reference
1	Hydro One's service territory covers more surface area than the average comparator and includes a significant proportion of rural and remote locations that can be difficult or require specialized equipment and procedures to access.	Section 3.1.1
2	In 2020, Hydro One initiated an annual standardized pole refurbishment program and a test and treat program that are similar to those of comparator utilities.	Section 3.1.2
3	Hydro One utilizes both visual and data dependent sound and bore inspection methods, with inspection rates that are lower than comparators.	Section 3.1.3
4	Hydro One's distribution poles are on average older than the comparator group.	Section 3.1.4
5	Hydro One replaces poles based upon condition and has a higher pole replacement rate (including poles replaced upon failure) as compared with comparators.	Section 3.1.4
6	Hydro One's pole replacement costs are comparable to the mean of the comparator group.	Section 3.1.4

The consideration and/or impacts of these key findings in the context of Hydro One's investment plan are discussed below:

Finding 1: Large Service Area

Hydro One has the lowest customer density in terms of customers per circuit-kilometer of line and per square kilometer of service territory (see DSP Section 3.3, Attachment 1, Figures 4 and 5). This observation highlights the challenges faced by Hydro One (including the difficulty in accessing rural and remote locations) due to the unique demands and characteristics of its distribution service territory and density of customers served. There are no actions required on the part of Hydro One in relation to this finding.

Finding 2: Pole Refurbishment

Hydro One introduced a structural refurbishment program and chemical retreatment program as recommended in the previous distribution pole replacement benchmarking study (which is further discussed below). Both programs will continue over the planning period, providing alternatives to pole replacement and extending the service life of Hydro One's distribution poles where feasible. To cost effectively mitigate pole-related risks through the DSP, Hydro One will continue to balance the opportunity to deploy structural/chemical retreatment solutions with the need for planned traditional pole replacement, in line with industry best practices.

Finding 3: Pole Inspections

Hydro One's overhead inspection program has been combined with its vegetation inspection program. This bundled work allows for more frequent visual inspections of Hydro One's overhead assets, including poles, without having to dispatch multiple crews to patrol the same assets.

In addition to the more frequent visual inspections, Hydro One will test poles on a 15 year cycle through the new test and treat program. These tests will collect additional data about pole condition and will through the application of retreatment (where appropriate) help extend the life of the poles.

Finding 4: Older Poles on Average

While the study found that Hydro One's distribution poles are on average older than the comparator group, it is important to note that Hydro One does not proactively replace poles based on the age of the pole. If poles are still in good condition, they will remain in service until replacement is required due to a change in their condition or other system needs. In terms of long-term expectations at the asset fleet level, this finding does highlight the existence of a sizeable population of older than average distribution poles that would be reasonably expected to deteriorate over time. There are no specific actions required on the part of Hydro One in relation to this finding.

Finding 5: Pole Replacement Rate

Hydro One has a higher pole total replacement rate (which notably includes an average of 0.2% of poles replaced annually by Hydro One due to failure) than comparator utilities. Between the many projects and programs that involve pole replacements (e.g., planned replacement program, emergency replacements, and other projects), Hydro One had an annual average total replacement rate of 1.2% between 2015 and 2019 and a forecasted average total pole replacement rate of 1.1% between 2020 and 2024 (DSP Section 3.3, Attachment 1, Figure 11). Moreover, the report noted that the comparators' replacement rates appear insufficient to sustain their poles over the long term and that Hydro One has the largest percentage of poles requiring replacement (4.62%) among the comparator group. When viewed in context of these factors, the study results show that Hydro One's overall pole replacement rate is reasonable.

Finding 6: Pole Replacement Unit Cost

Figure 14 in DSP Section 3.3, Attachment 1 compares Hydro One's unit price for the pole replacement program with other utilities costs. Hydro One's unit costs are at the mean of the comparator group.

3.3.1.3 PAST STUDY

In accordance with OEB's direction, this section provides an update on Hydro One's response/actions stemming from the previous pole replacement benchmarking study (see EB-2017-0049, Exhibit B1-1-1, Section 1.6, Attachment 1). Table 2 is a list of the recommendations from that study.

Table 2 - Past Study Pole Replacement Program – Key Recommended Actions

#	Recommended Actions
1	Consider modifying the pole replacement program to include more complete pole inspections (sound, bore, excavation) and a longer (approximately 10-year) inspection cycle – the OEB would need to approve the change in inspection cycle.
2	Expand the existing centralized program management and pole selection approach to cover 90-95% of the replacement / refurbishment work on poles in a given year, leaving the remainder to be guided by the local staff while still meeting the centralized strategy and replacement criteria.
3	Where geography and/or pole density permit, consider the use of dedicated pole replacement crews.
4	Consider modifying the program to include a rigorous pole refurbishment option, when appropriate.

Recommendation 1: Pole Inspection Process

This recommendation has been implemented in line with the intended objectives, as further discussed in relation to the test and treat program under Finding 3 in Section 3.3.1.2 above.

Recommendation 2: Program Management

This recommendation has been implemented. Asset Management leverages inspection and testing data to determine which poles are in poor condition and appropriately prioritizes them as part of the investment planning process (for details, please see DSP Section 3.7). The result is all poles prioritized for replacement are based on a centralized strategy and replacement criteria.

Recommendation 3: Pole Replacement Crew

When there is a large number of poles that require replacement on the same section of line, crews are often dedicated to completing this work. While having dedicated crews for a pole replacement program may be the most efficient approach insofar as pole replacements are concerned, it may negatively affect the efficiency of other work programs. For example, sometimes flexibility in work assignments is needed to respond to other work demands (e.g., new connections, defect corrections and restoring power in a storm situation). Further, if there is component replacement in the same area as a pole replacement, it is likely more efficient to have the same crew complete both types of work instead of sending two dedicated crews to the same site. Hydro One's productivity and continuous improvement plan is detailed in SPF Section 1.4.

Recommendation 4: Pole Refurbishment Program

This recommendation has been implemented as discussed under Finding 2 in Section 3.3.1.2 above.

3.3.2 STATION REFURBISHMENT PROGRAM STUDY - GUIDEHOUSE & FIRST QUARTILE

3.3.2.1 STUDY OVERVIEW

The consortium of Guidehouse and First Quartile completed a study to quantify and evaluate the unit costs of Hydro One's distribution station refurbishment program through benchmarking comparison and analysis against a group of comparator utilities. Similar to the pole replacement study, in addition to cost data, data collected in relation to demographics and work practices help to inform a proper understanding of the cost performance results in light of the utility's unique circumstances. As detailed below, the study concluded, among other things, that Hydro One has lower than average costs to replace power transformers and refurbish distribution stations (on a per transformer basis).

3.3.2.2 STUDY RESULTS

The key findings of the Distribution Station Refurbishment Program Study are shown in Table 3. A copy of the study report is provided as DSP Section 3.3, Attachment 1.

Table 3 - Distribution Station Refurbishment Program Study - Key Findings

#	Key Finding	Study Reference
1	Hydro One's distribution substation assets service a higher percentage of rural territory versus comparators.	Section 3.2.1
2	Hydro One's distribution substations have higher average peak loading (as a percentage of nameplate capacity) than comparators, and in contrast with comparators are primarily comprised of single transformers that are sufficient for the population that they serve.	Section 3.2.2
3	Hydro One has lower than average costs to replace power transformers as they are primarily comprised of smaller transformers.	Section 3.2.3
4	Hydro One has lower than average costs for distribution substation refurbishments on a per transformer basis.	Section 3.2.4
5	Hydro One has recently focused more on component-centric projects, which aligns with the most common approach to station refurbishment among comparator utilities.	Section 3.2.5
6	Hydro One has also introduced a lower cost unfenced pad mount transformer solution for replacement of smaller substations (where feasible), which most other utilities have not considered.	Section 3.2.6

The consideration and/or impacts of these key findings on Hydro One's investment plan are discussed below:

Finding 1: Substation assets service a higher percentage of rural territory

The study noted that 70% of Hydro One's service territory are rural areas with low population density. This shows the unique demands/characteristics associated with Hydro One's distribution system – one that is characterized by low customer density and small substation transformers to serve smaller numbers of local customers. There are no actions required on the part of Hydro One in relation to this finding.

Finding 2: Higher peak loading single transformer substations

The study stated that Hydro One had by far the highest percentage of single-transformer stations in the comparator group. Hydro One has the highest percentage of single transformer substations since the system is setup such that in the event of contingencies involving the failure of single bank transformers, Hydro One relies on the availability of a fleet of Mobile Unit Substations (MUSs) (see DSP Section 3.2, subsection 3.2.2.4) that are driven to the relevant station and connected (where connection poles are available) to restore load in place of the failed transformer. The sharing of MUSs amongst many substations is a less costly alternative compared to designing rural substations with a second transformer bank for failure contingency.

The study also noted that Hydro One's Distribution substation transformers had the highest peak loading as a percentage of their nameplate rating in the comparator group. Consistent with this finding, Hydro One notes that its planned loading limits for distribution substations are normally above the manufacturer nameplate rating.

No specific actions are required on the part of Hydro One in relation to these findings.

Finding 3: Lower than average transformer replacement costs

The study found that Hydro One has lower than average costs to replace power transformers, with a partial reason being that Hydro One substations are primarily comprised of smaller transformers. Hydro One's transformer replacement costs are appropriate based on the study findings.

Finding 4: Lower than average substation refurbishment costs

With respect to station refurbishment projects, the study found that Hydro One had lower than average costs than the comparators. In this regard, costs were normalized and compared on a per-transformer basis in the study, consistent with the single-transformer configuration of most of Hydro One's distribution stations. This finding provides further support and validation for Hydro One's approach to station refurbishment from a cost perspective.

Finding 5: Focused more on component-centric projects

Under its current approach for managing the distribution station transformer fleet, Hydro One releases projects that focus on planned transformer replacements and other station component replacements as required to accommodate the transformer replacement. If there are other station assets that are in poor condition and in need of replacement, they are bundled with the transformer replacement project, however other component assets in good or fair condition are not be replaced. Through this approach, Hydro One aims to more effectively target the high risk components in Hydro One's distribution stations. Programs for the replacement of individual stations components including reclosers and MUS connection structures, will continue. Hydro One's planned approach is in line with the finding that most comparator utilities also focus more on component-centric projects.

Finding 6: Introduced a lower cost unfenced pad mount transformer solution

The study noted that Hydro One has a lower cost unfenced pad mount transformer solution for smaller substations. This solution is an alternative to a station refurbishment project that involves removing the station components, including the power equipment, structures and fence. The station is then replaced with pad mounted transformers located with underground primary and secondary cables. This lower cost solution is not feasible at all of Hydro One's substations due to feeder loading requirements and other technical reasons. Where feasible, the solution offers a less costly alternative to a full station rebuild. Based on the findings of the study, Hydro One is one of the few companies in the comparator group that is leading the way in deploying this innovative solution.

3.3.2.3 PAST STUDY

In accordance with the OEB's direction, this section provides an update on Hydro One's response/actions stemming from its previous station refurbishment benchmarking study (see EB-2017-0049, Exhibit B1-1-1, Section 1.6, Attachment 1). Table 4 outlines the key recommendations from that study.

Table 4 - Past Study Distribution Station Refurbishment Program – Recommended Actions

#	Recommended Actions
1	Consider implementing a formal data governance process for equipment performance and maintenance data and incorporating that information into the asset condition scoring and project planning process.
2	Enhance cost and work completion reporting for individual projects and implement a formal change control process.
3	Develop and implement more comprehensive key performance indicators, including in-progress project cost performance measures, assessments of project/program impacts on substation reliability, maintenance costs, and overall asset health.

Recommendation 1: Project Planning Process

The study recommended implementing a formal data governance process for equipment performance and maintenance data, and to incorporate that information into the asset condition scoring and project planning process.

Hydro One has a formal governance process in-place for maintenance data which informs asset condition scoring. Additionally, Hydro one continuously looks for ways to improve this data. Examples of such improvements include the creation of new SAP measurement points/documentation to track condition-related issues, such as transformer oil leaks, under-load tap changer minimum and maximum positions, and poles and station structures that lean excessively.

The study also recommended incorporating test results and maintenance history data for switching and protection equipment and relays into the asset condition scoring and project planning process. In this regard, Hydro One notes that its station projects are driven by condition-based replacements of major components (e.g., transformers, reclosers and structures). By contrast, switches, protection and relay equipment – as relatively minor assets whose failures pose less risks – do not drive such projects and are instead repaired or replaced when deemed defective.

Recommendation 2: Project Management Execution

The study recommended enhancing cost and work completed reporting for individual projects, and implementing a formal change control process.

Hydro One has a formal change control process in place. Station refurbishment projects (including full station rebuilds, planned transformer replacements and pad-mount transformer installations) are released as separate investments, which facilitates enhanced cost reporting and progress tracking.

Recommendation 3: Key Performance Indicators (KPIs)

The study recommended developing a more comprehensive set of key performance indicators, including project cost performance measures and assessments of project impacts on substation reliability, maintenance costs and overall asset health.

Hydro One tracks project cost performance through the "Station Refurbishment Gross Cost Per MVA in $" metric (DSP Section 3.5, subsection 3.5.1.3). This metric measures Hydro One's success in cost-effectively delivering station refurbishment projects. Since these projects will vary in costs due to the different scope of work for each project, this metric should be viewed as a trend over a number of years to enable cost performance comparisons over time and inform potential improvements.

Hydro One tracks the impact of station transformer failures on the reliability of the distribution system as a whole. The intention of station refurbishment projects is to replace assets in poor condition prior to failure (not after), so monitoring the impact of station projects on the reliability of individual stations is not meaningful.

Hydro One monitors the impact of station projects on overall asset condition. Details of the condition of station assets can be found in DSP Section 3.2, subsection 3.2.2.

3.3.3 VEGETATION MANAGEMENT PROGRAM STUDY – CN UTILITY

3.3.3.1 STUDY OVERVIEW

CN Utility Consulting, Inc. (CNUC) carried out a benchmarking study of Hydro One's Utility Vegetation Management (UVM) program against industry comparators (DSP Section 3.3, Attachment 2). Hydro One's UVM program is known as the Optimal Cycle Protocol (OCP), which was introduced pursuant to the recommendations outlined in Clear Path Utility Solutions, LLC's (Clear Path) 2017 Forestry Assessment report. Hydro One's transition to OCP represented a shift from a corridor-based UVM strategy to a defect-driven program that is focused on high-risk trees and tree-power line defects. CNUC previously completed the 2009 and 2016 UVM benchmarking studies for Hydro One. The 2020 benchmarking study had the following three objectives.

1. Review Hydro One's distribution system attributes in relation to peers and other industry survey respondents.
2. Compare and contrast Hydro One's UVM program with peers and other industry survey respondents.
3. Analyse the results to date of Hydro One's OCP implementation.

CNUC leveraged data from its survey – Utilities & Vegetation Management in North America: A 2019 Utility Forestry Census of Tree Activities & Operations survey (CN-UWSP Survey) in partnership with the University of Wisconsin-Stevens Point (UWSP). CNUC also used a supplemental survey for 2020 to generate additional insights into Hydro One's UVM practices. The various comparator groups referenced below (e.g. "Peer 2019" and "AR 2019", where "AR" denotes "All Respondents" that participated in a particular survey) are described in detail in the benchmarking report (see DSP Section 3.3, Attachment 2, page 1).

3.3.3.2 STUDY RESULTS

Table 5 - Vegetation Management Benchmarking Study (CNUC) - Key Findings

#	Key Study Findings	Study Reference
1	HONI's number of customers is statistically less than the Peer 2019 average and is statistically greater than the AR 2019 average. But, HONI has a significantly larger system in terms of distribution ROW km compared to both the Peer 2019 and AR 2019 groups. The result is that HONI has a customer density that is much lower than other utilities.	Section 4.1 System Attributes
2	HONI has a distribution system that is much more rural and remote in comparison to other utilities. This is notable because rural and remote areas are more difficult and expensive to access and manage.	Section 4.1 System Attributes
3	HONI's scope of UVM work, though statistically different from the Peer 2019 and AR 2019 group generally, is not significantly different from the Peer 2019 group for under clearances. HONI's clearances and the interval of work result in percentages of reactive work and trees in contact at the time of work that have no statistical difference from that of the Peer 2019 group but differ from the AR 2019 group.	Section 4.2 Program Attributes
4	HONI has a rate of removal that is three-times greater than other survey respondents. HONI has shifted its scope of work to include-ROW hazard trees as well. The 2017 Forestry Assessment estimated that 90% of HONI's distribution outages are caused by this tree population. Therefore, this high rate of removal is likely to pay dividends in the future in improved reliability from hazard tree reduction. Additionally, any tree removal reduces the total tree inventory on the system. A percentage of in-growth is expected each year as new trees seed in or resprout, so to avoid increasing future workloads, reducing this inventory is key.	Section 4.2 Program Attributes
5	HONI's use of herbicides was behind that of Peer 2016 respondents and has not decreased since that time, while the Peer 2020 group has increased adoption by over 20%. The use of herbicides is an industry best management practice in reducing the in-growth and regrowth of removed trees.	Section 4.2 Program Attributes
6	HONI reduced the work interval by more than half and has done so without increasing the average program budget.	Section 4.3 Operational Outcomes
7	HONI has an average program budget 2.5 times that of the Peer 2019 group, however, this disparity is largely explained by HONI's unique and challenging UVM setting. HONI has a similarly sized customer base as the Peer 2019 group but twice the number of distribution ROW kilometres.	Section 4.3 Operational Outcomes

8	HONI has seen a reduction in cost per managed ROW km of over 50% from 2016 compared to the average of the OCP period (2018-2020).	Section 4.3, 4.4
9	HONI's non-FM SAIDI remains higher than the Peer 2020 group. A higher non-FM SAIDI is expected due to HONI's rural and remote service territory. However, since the OCP implementation began, there has been a clear shift in the HONI Non-FM SAIDI trend for the better	Section 4.3,4.4
10	Through implementation of the OCP, HONI has reduced its maintenance interval from 9.5 years to a projected first cycle of 4.1 years. This interval will continue to be optimized through a defect-driven approach in subsequent cycles.	Section 4.3, 4.4

Finding 1: HONI has a significantly lower customer density compared to Peers

Hydro One Distribution serves a large majority of customers in some of the lowest population density regions in the Province of Ontario. 98% of Hydro One Distribution's ROWs are classified as rural in the CNUC study. HONI's number of customers is statistically lower than the comparator groups in the CNUC study; however, due to a significantly larger service territory, HONI has a significantly lower customer density than the comparators. This is a critical consideration, particularly when examining UVM program expenditures. There are no actions required on the part of Hydro One in relation to this finding.

Finding 2: HONI has a largely rural distribution service territory

The rural and remote nature of HONI's service territory is an important system attribute and a driver for low customer density. 98% of HONI's ROW km are classified as rural or remote compared to less than 60% for the relevant comparator groups. This means that only 2% of HONI's ROW km are suburban or urban in comparison to over 40% for the relevant comparator groups. This is notable because urban and suburban areas are more easily accessed and managed. There are no actions required on the part of Hydro One in relation to this finding

Finding 3: HONI's reactive work and trees in-contact are in-line with its Peer group with certain Scope of Work differences

Hydro One's defect driven program (OCP) focuses on high risk trees and tree power line conflicts that through the use of highly skilled arborists ensures the required clearance without removal of all limbs of a tree on the side closest to the powerline along a ROW. In contrast, several comparator utility respondents remove all tree limbs on the wire side of a tree. These under clearances are not significantly different from the Peer 2019 group. The *2017 Forestry Assessment* recommended a defect-driven strategy (which HONI has shifted to) that focuses on defects (hazard trees and contacts) to reduce costs per km while still producing positive safety and reliability outcomes (see EB-2017-0049, Exhibit B1-1-1, Section 1.6, Attachment 2).

Finding 4: Hydro One has a tree removal rate much greater than its Peer group

The 2017 Forestry Assessment recommended a greater emphasis on reducing high risk trees. HONI has responded by increasing its removals from 20% in 2016 to 60% in the period 2018-2020 of all vegetation defects treated. This increase in tree removal comes due to a change in work scope as part of HONI's OCP strategy that includes off ROW trees. In the 2017 Forestry Assessment, it was estimated that as much as 67% of the three-year projected defect workload would be related to off-ROW trees that were not part of the pre-OCP UVM work scope. The report also estimated that 90% of distribution system outages appeared to be caused by off-ROW tree and branch failures. The high tree removal rate is expected to decrease in the second cycle of the OCP program and reduce future vegetation management work needed. There are no further actions required on the part of Hydro One in relation to this finding.

Finding 5: Decrease in Herbicide use on Hydro One ROWs.

When Hydro One switched to OCP, off ROW trees were included in the specification and the resulting tree removal rate increased to 60% from 20% of all defects managed. In order to fund the increased removal rate without additional funding to the program, road side brush control was paused until the second cycle of the OCP which is expected to see a reduction in the tree removal rate. The pause of road side brush control limited the opportunities for herbicide application which resulted in the reduction of herbicide use. As CNUC noted, the use of herbicides is an industry best management practice and is a key tool in reducing the in-growth and regrowth of removed trees. During the second cycle of OCP, Hydro One will increase its use as brush control is resumed.

Finding 6: Hydro One's UVM interval has been reduced by half without an increase in funding

The kilometers of ROW managed through the OCP program has increased from 11,753 km in 2016 to an average of 25,695 km annually over the past three years. Hydro One expects to inspect and clear approximately 95% of its ROWs by the end of 2021 at least once (within 4 years of the inception of the program). There are no further actions required on the part of Hydro One in relation to this finding.

Finding 7: Hydro One has a high budget compared to comparators, but also has proportionally higher ROW kms

HONI has a distribution system with more than twice the ROW kilometers compared to the Peer 2019 group and nearly four-times larger than the AR2019 average, which as CNUC noted is an important consideration in examining UVM distribution expenditures. Hydro One also has nearly the same number of customers as the comparator group while having twice as many ROW kilometers. Examining UVM distribution expenditures on a per-managed ROW kilometer basis helps to better compare costs with the comparator group. Hydro One's average three year cost per managed kilometer of ROW from 2018 to 2020 adjusted to 2020 dollars was $5,508. This is not significantly different from the Peer 2016 comparator group's average of $4,830/km, is higher than the Peer 2019 comparator group' average of $3,600/km, and lower than AR2019 comparator group's average of $6,860/km. Hydro One has seen over a 50% reduction in cost per managed ROW km after adopting the OCP strategy while decreasing the overall interval between UVM clearing on the ROWs, and having a three times higher tree removal rate than the comparators in the study.

Finding 8: Hydro One has seen a reduction in cost per managed km of over 50%

Since transitioning to the OCP, Hydro One's cost per managed km has decreased from $11,860/km in 2016 to $5,509/km (OCP average 2018-2020). There are no further actions required on the part of Hydro One in relation to this finding.

Finding 9: Hydro One has reversed its worsening vegetation caused system reliability trend

Hydro One's vegetation caused non-FM SAIDI from 2010 to 2017 shows a worsening trend, which was not expected to change without intervention. There had been a significant backlog of vegetation work and no expectation for this trend to change without a significant change in the UVM strategy. In 2018, Hydro One shifted from a corridor-based UVM approach to a defect-driven program (OCP) that is focused on high-risk trees and tree-power line conflicts. The implementation of OCP has resulted in a 13% improvement in vegetation-caused SAIDI from 2017 to 2020. It should also be noted that 2020 was an above average storm year in which Hydro One's service territory experienced 41 storm days, excluding FM days, while Hydro One recorded on average 32 storm days annually from 2015 to 2019. There are no further actions required on the part of Hydro One in relation to this finding.

Finding 10: Hydro One has significantly reduced its average maintenance interval for UVM

In its previous 2016 report, CNUC recommended that Hydro One bring its entire distribution system to a four to eight year flexible cycle that eliminates the backlog of vegetation management work. In this regard, Hydro One has shifted from a corridor-based UVM approach to a defect driven program (OCP) that is focused on high-risk trees and tree-power line defects. The kms of right of way managed through the OCP program has increased from 11,753 kms in 2016 to an average of 25,695 kms annually over the past three years. Hydro One expects to inspect and clear approximately 95% of its ROWs by end of 2021 at least once (within 4 years of the inception of the program). There are no further actions required on the part of Hydro One in relation to this finding.

3.3.3.3 PAST STUDY

The best practice and implementation recommendations found in the Vegetation Management Program Study are summarized in Table 6. The study report can be found as see EB-2017-0049, Exhibit B1-1-1, Section 1.6, Attachment 2.

1 **Table 6 - Past Study Vegetation Management Program – Recommendations**

#	Recommendations (Section 1.8 of 2016 CNUC study)	Study Reference
1	Bring the whole distribution system to a four to eight-year flexible cycle that is trued up each year to ensure backlogs do not creep back into the schedule. This will enable a more effective herbicide program, better off-ROW tree risk management, and reduce workload over the long term. Reduce the current backlog over the next decade through innovations, automation and changes in labour mix. See Recommendations 2, 3, 4, 6, and 9 (below).	Sections 4.1 - 4.3, 4.6, 4.8
2	Improve through innovation, analytics, technology, and communication the UVM program. This will improve understanding of the workload and enable more effective work planning and cost/resource predictions.	Sections 4.3, 4.4
3	Improve productivity and control costs by utilizing higher percent of Hiring Hall and contract workers to perform lower safety and liability risk activities such as work planning, herbicide applications, and brush-clearing. This will lower unit costs.	Section 4.4.2
4	Strategically increase herbicide usage for cost-effective results. This will ensure ROWs stay clear between shorter cycles of management and lower the long term cost.	Sections 4.1.3, 4.2.5, 4.2.7, and 4.3.1
5	Develop a UVM outage investigation protocol that expands on the current cause codes and utilizes UVM personnel. This will improve capability to predict tree failure modes and guide future tree risk mitigations.	Section 4.5.3
6	Synchronize the annual asset inspections with the UVM work planning program to quantify system vegetation conditions based on performance metrics for maintaining air space around conductors. This will improve workload understanding and provide annual performance metrics for system conditions.	Section 4.3.1
7	Improve and increase the Tree Risk Assessment Program to reduce outages caused by off-ROW trees. This will, with the help of lessons learned through outage investigations, improve reliability by reducing outages caused by trees or branches falling into overhead lines.	Sections 4.3.1, 4.5.3, 4.7 and Appendices F and G
8	Identify fixed cost increases and overheads allocated to UVM to ensure cost effects of changes to the program are portrayed accurately. This will enable a better understanding of improvements to production and other cost reduction measures.	Sections 4.1 (4.1.1, 4.1.3, 4.1.4) and 5
9	Improve equipment and personnel utilization. This will lower unit costs by improving efficiency and optimizing equipment availability.	Section 4.4 (4.4.1, 4.4.2)

Recommendation 1: Reduce Cycle Times

The recommendation has been implemented through the implementation of the OCP UVM strategy. The OCP strategy will allow approximately 95% of the ROW kms to be managed at least once 4 years after starting the program in 2018. By including off-ROW trees within OCP, this change caused an increase in the tree removal rate from 20% to 60% of all treated vegetation defects. In order to fund the increased removal rate, road side brush control program was paused until the second cycle of the OCP which is expected to see a reduction in tree removal rate. As CNUC noted, the use of herbicides is an industry best management practice and is a key tool in reducing the in-growth and regrowth of removed trees. During the second cycle of OCP, Hydro One will increase its use of herbicide as its shifts focus to addressing brush.

Recommendation 2: ROW Clearing Efficiency

Hydro One is collecting ROW vegetation defect data as part of its vegetation patrol, which is performed to prepare work prescriptions ahead of Forestry work execution. Hydro One is utilizing data analytics to optimize work specifications and feeder prioritization to improve safety and reliability. Hydro One employs skilled arborists that are able to identify and mitigate vegetation defects taking into account climatic conditions and vegetation species that prove to be detrimental to the performance and safety of ROWs.

Recommendation 3: Improve productivity and control costs by utilizing higher percent of hiring hall and contract workers

Hydro One strives to optimize unit costs and productivity through flexible resource options, while maintaining alignment within the parameters of union collective agreements. This includes the utilization of regular, hiring hall and contract staff. Hydro One was able to augment its regular and hiring hall staff through years 2018 to 2020 with contract workers.

Recommendation 4: Increased Herbicide Usage

The herbicide application as a part of roadside brush control was paused to fund an increased tree removal rate including trees that were off-ROW that were a significant source of tree caused outages. The 2017 Forestry Assessment report estimated that 90% of tree caused distribution system outages appeared to be caused by off-ROW trees that were not included in the UVM work specification. When Hydro One switched to OCP, off-ROW trees were added to the specification and the resulting tree removal rate increased from 20% to 60% of all defects managed. To fund the increased removal rate without any additional funding to the program, road side brush control program was paused until the second cycle of the OCP which is expected to see a reduction in the tree removal rate. As the road side brush control work is resumed, the use of herbicides as a vegetation management tool will be applied as appropriate.

Recommendation 5: Outage Investigation Protocol

Hydro One has implemented a detailed outage investigation process. There are no further actions required on the part of Hydro One in relation to this recommendation.

Recommendation 6: Synchronize annual asset inspections with vegetation management

Hydro One has adopted the recommendation by adding the required asset inspections (overhead line inspections) in the scope for the OCP Defect inspection patrol since 2019. There are no further actions required on the part of Hydro One in relation to this recommendation.

Recommendation 7: Tree Risk Assessment Program

According to the 2017 Forestry Assessment report, vegetation caused outages from off-ROW trees accounted for 90% of all outages, including 50% that were caused by tree or branch failures that were dead or had visible signs of decay and disease. Hydro One has responded to this recommendation by including off-ROW trees in its UVM scope of work and has increased the tree removal rate three fold from 20% to 60%. As part of the OCP program, all trees on and off the ROW are assessed for their risk to strike the power line, and are managed if deemed appropriate. There are no further actions required on the part of Hydro One in relation to this recommendation.

Recommendation 8: Identify fixed cost increases and overheads allocated to UVM to ensure cost effects of changes to the program are portrayed accurately.

Hydro One's hourly rate charged to the UVM program incorporates direct labour, fleet and other equipment costs. In addition to these direct costs, hourly rate also reflects indirect costs including Administration, Health& Safety, costs of support staff including planning and program management staff directly attached to the forestry program. There are no further actions required on the part of Hydro One in relation to this recommendation.

Recommendation 9: Improve equipment and personnel utilization.

Hydro One is focused on maximizing the utilization of its equipment and personnel by combining programs where feasible to minimize multiple crew trips. In 2019 Hydro One combined the Overhead Asset Inspection through Distribution Lines Patrol program with the OCP defect inspection patrol conducted by Forestry technicians to maximize crew and equipment utilization.

Hydro One's OCP utilizes a mix of part time and full time staff to execute the programs. The resource and the equipment/fleet needs are constantly reviewed against the yearly work needs and optimized as required. Part time staff are mobile and are brought on to augment production and meet any localized resource shortfall during the peak months of the program. Similar to labour needs, fleet utilization is closely monitored throughout the year and fleet adjustments made as needed.

3.3.4 OPTIMAL CYCLE PROTOCOL – CLEARPATH

3.3.4.1 STUDY OVERVIEW

Clear Path carried out a performance assessment of Hydro One's OCP relative to the projections outlined in the 2017 Forestry Assessment that served as the basis for OCP implementation. A third party, Arbor Metrics Solutions ULC was retained by Clear Path to perform physical field surveys.

3.3.4.2 SUMMARY OF FINDINGS AND RECOMMENDATIONS

The best practice and implementation recommendations found in Clear Path's report – *Hydro One Optimal Cycle Protocol (OCP) First Cycle Performance Assessment* – are summarized in Table 7. The study report can be found in DSP Section 3.3, Attachment 3.

Table 7 - Key Study Findings

#	Key Study Findings	Study Reference
1	A statistically valid and random sampling of completed OCP feeders found a 96% improvement in the number of defects from the 2017 survey relative to 0-2-yr. slot class.	1.3
2	An analysis of Tree Caused Outages (TCOs) comparing non-OCP feeders with feeders on which OCP work has been executed demonstrated an improvement of between 23% and 41%	1.3
3	First cycle workload (i.e., number of trees trimmed or removed pursuant to the OCP) for 2018-2020 was 13% greater than 2017 modeled projections.	1.3
4	Actual unit cost (trees & km) was significantly higher than 2017 modeled cost, due to factors that were not known or anticipated and could not reasonably have been accounted for in the initial projections, as described in Section 5.3 of the report, including higher than projected defect workload.	1.3

Table 8 - Recommendations

#	Recommendations	Study Reference
1	Potential opportunity to modify cycle length on certain feeders or areas.	1.3

Finding 1: Significant improvement in the number of defects on feeders that have completed OCP

Vegetation defects are an undesirable condition, defined as trees and vegetation growing into high voltage conductors and trees with strike potential that exhibit observable conditions such as dead, diseased, decadent, or structurally unsound. During storms, structurally sound trees with no observable conditions (i.e., not considered defects) may still fall into the lines and result in a tree cause outage. The survey results from the 2021 Clear Path report indicate that the OCP approach applied by Hydro One is effective in managing defects. Upon the completion of the first cycle with the OCP approach, it is forecasted that the defect rate will be less than 2.2 defects per kilometer, which is substantially lower than the pre-OCP defect rate of 8 defects per kilometer. After the first full OCP cycle is completed, the overall system conditions will have improved from an estimated 800,000 pre-OCP defects to 90,000 post-OCP defects.

Finding 2: Post OCP feeders show a 23% to 41% improvement in the number of tree caused outages (TCOs).

TCO frequency was analyzed on an event per 100 km basis, by month for the years 2018 through 2020 by segregating TCO occurrence on feeders before OCP work and on feeders after OCP work was performed. This approach helps to normalize the data and mitigate year-to-year weather variability that impacts reliability, illustrating a more accurate representation of OCP efficacy. In each of the years analyzed (2018, 2019 and 2020), feeders where OCP has been completed demonstrated fewer TCOs than feeders where OCP has not been completed. An analysis of TCOs comparing feeders that have not undergone the OCP treatment, with feeders on which OCP work has been executed demonstrated an improvement of between 23% and 41%. The improvement was particularly evident during force majeure events.

Finding 3: First cycle workload was 13% greater than 2017 modelled projections.

First cycle workload projected in the 2017 Forestry Assessment were estimated at 21 defects per km. The actual first cycle defects founds for vegetation work in the first three years of OCP (2018-2020) were 23.8 defects per km averaged 2018 through 2020, exceeding the 2017 projection by 13%.

Finding 4: Actual unit costs were higher than the 2017 projection

The OCP program involves two distinct steps, notification of defects and execution of defects. Notification is a work planning requirement that ensures defect identification is completed as prescribed within the parameters of specification and all contractual obligations are met in advance of work execution. Notifications and work planning in advance of work execution allows for evaluation of the conditions of vegetation and drives efficiencies with respect to scope of work and costs for each type of work. The number of defects being notified per kilometer and the cost of executing those defects both have an impact on the overall unit cost encountered on dollars per managed kilometre basis.

Clear Path noted that the unit cost projections from the 2017 Forestry Assessment report were based on information available at the time. Clear Path cited the following unanticipated factors which contributed to higher than projected unit costs:

- Defect workload density was 13% higher averaged from 2018-2020 than projected.
- Higher ratio of tree removals over tree trims than modelled.
- Notification costs were significantly underestimated and further compounded by technology deployment
- Brush control work on sub-transmission feeders was not modelled in the original cost projections
- Less contracted staff used for execution work than originally modelled.
- One time cost incurred through lack of productivity in 2019 due to safety stand-down for forestry organization for 8 working days.

- The labour costs used in the 2017 study modelled an industry standard 2-person crew with one utility arborist and one lower cost crew member, which did not materialize.

There are no actions required on the part of Hydro One in relation to this finding.

Recommendation 1

Hydro One is collecting data on vegetation defects along ROWs as feeders undergo OCP clearing. Hydro One is utilizing this data and system performance to optimize vegetation cycle lengths on feeders.

3.3.4.3 PAST STUDY

Clear Path was engaged by Hydro One to perform a comprehensive field assessment of Hydro One's distribution system and its vegetation management practices and determine the optimal vegetation maintenance cycle to reduce vegetation caused outages and improve safety along rights of ways without increasing overall vegetation management cost. In response to the study Hydro One switched from the full corridor based vegetation management strategy to a defect focused vegetation management strategy (OCP) (see EB-2017-0049, Exhibit Q-1-1, Attachment 2).

Hydro One embarked on the OCP strategy across the province in 2018 and significantly increased the number of kms managed. Off-ROW trees identified as a major source of outages were added to the defect specification. Hazard trees both on and off the right of way were identified using a hazard tree assessment criterion and the overall tree removal rate increased significantly. The 2021 ClearPath Assessment Report provides an assessment of Hydro One's implementation of defect driven UVM strategy from 2018 through 2020.

3.3.5 AMI VENDOR METER SERVICE LIFE ATTESTATION - TRILLIANT

In EB-2017-0049, the OEB directed Hydro One to explore with the manufacturer its basis for the estimated service life of smart meters of 15 years. This information was obtained from the vendor, Trilliant, and is documented in correspondence from the company.

Correspondence from Stephen Lupo, Senior VP Trilliant on Meter Expected Service Life (November 29, 2019) can be found in DSP Section 3.3, Attachment 4. The key findings from this correspondence are summarized in Table 9.

Table 9 - Key Findings – AMI 1.0 Service Life Vendor Attestation

#	Key Findings	Study Reference
1	Trilliant attests that it designs its products to operate for a period of 15 years. Independent laboratory analysis commissioned by Trilliant of its SecureMesh radio, the key meter component that enables it to reliably communicate, supports a minimum expected service life of 15 years.	Correspondence
2	Trilliant has indicated that it does not guarantee a minimum 15-year service life and that actual meter performance may differ materially from minimum service life. Trilliant recommends a conservative approach to replacing metering equipment on a meter replacement cycle that supports up to and including the 15th year of service to balance maximum service life and security of service.	Correspondence

The consideration of the vendor-attested meter life is discussed together with the findings from the Accelerate Life Testing Study (ALT) (DSP Section 3.3, Attachment 5) in Section 3.3.7 below.

3.3.6 ACCELERATED LIFE TESTING OF METERS - HYDRO QUEBEC

3.3.6.1 STUDY OVERVIEW

In order to verify the vendor-expected meter service life, corroborate information from benchmarking and other studies,[2] and better understand the root causes of its AMI meter failures, HONI engaged Hydro Quebec to independently design and perform Accelerated Life

[2] Asset Depreciation Study for the Ontario Energy Board, Kinectrics Inc. Report No K-418033-RA-001-R000, July 8, 2010, referenced in DSP Section 3.2 Asset Component Information and Life Cycle Strategies

Testing (ALT) on HONI AMI meters and report on results. ALT is the process of testing samples from a meter population and subjecting them to stressors that simulate service life by reducing time-to-failure without introducing any new failure mechanisms. By analyzing the meter's response to such tests, projections can be made (within certain confidence levels) regarding meter service life. Hydro Quebec has specialized expertise in designing and conducting ALT studies and offers a range of facilities for performing various mechanical, electrical, thermomechanical, climatic, temperature cycling, and temperature-rise testing.

3.3.6.2 STUDY RESULTS

The AMI ALT study can be found at DSP Section 3.3, Attachment 5. The study focused on L+G Focus ALF meters equipped with Trilliant GEN1 and GEN3 communications boards. Stemming from the vendor's initial meter design, GEN 1 meters were installed in approximately 2007-2009 and comprise approximately 50% (661,000 meters) of Hydro One's total meter population; whereas GEN 3 meters based on the subsequent meter design and were installed after 2009 and comprise approximately 35% (476,000 meters) of the total meter population. The key findings of that study are summarized in Table 10.

Table 10 - Key Findings – GEN 1 and GEN 3 Meter ALT Study

#	Key Findings	Study Reference
1	Both GEN 1 and GEN3 meters remained in their accuracy class and at no time were metering errors observed.	Section 3
2	A number of sources of meter failures were identified including electrolyte leakage from capacitors, transformer failures, LCD component failures, and cracked solder joints.	Section 3
3	There were significant failures in GEN 1 meters involving the rapid degradation of capacitor C21, which must properly function if the meters were to reliably communicate. The C21 capacitor in 18 of the 19 GEN 1 meters that underwent High Temperature Operating Life (HTOL) testing rapidly reached the capacitor manufacturer's end-of-life specifications, eventually leading to complete communication failure in 14 of the 19 meters.	Section 7.1, 7.2, 7.3
4	Applying the study's GEN 1 meter findings (i.e., Time to Failure and Acceleration Factors) at the recommended confidence level of 50%[3] results in projections of approximately 88% or 579,000 meters failing through 2027.	Section 8.5.11 Section 8.5.12
5	Although GEN 3 meters performed better than GEN 1 meters, failure analysis identified a number of GEN 3 failure modes (e.g., power transformer failures, cracked solder joints) but accurate failure distributions could not be produced due to the limited number of failures observed.	Section 1.0

The consideration of these key findings is discussed together with the findings from the AMI replacement cost benchmarking study in Section 3.3.8 below.

3.3.7 AMI REPLACEMENT COSTS BENCHMARKING - GUIDEHOUSE AND FIRST QUARTILE

3.3.7.1 STUDY OVERVIEW

In EB-2017-0049, the OEB directed Hydro One to expand benchmarking to "other capital programs". In response, Hydro One included the AMI program as one of the additional areas to undergo benchmarking given its significance to the company's service obligations and work portfolio overall. The resulting benchmarking study was undertaken by Guidehouse in partnership with First Quartile Consulting, and provides a comparative view of Hydro One's practices and unit costs for AMI replacement against a group of North American comparator utilities.

[3] Also known as the median rank, a balanced assessment for the probability of failure and the closest value to the actual results observed in testing.

3.3.7.2 STUDY RESULTS

The AMI Benchmarking Study can be found at DSP Section 3.3, Attachment 6. The key findings regarding that study are summarized in Table 11.

Table 11 - Key Findings – AMI Benchmarking Study

#	Key Findings	Study Reference
1	Hydro One was among 44% of respondents who had an expected AMI meter service life of 15 years, which represents the mode of the group.	3.3.1
2	Hydro One's average meter acquisition cost ($160) is 10% higher than the mean of the comparator group ($145). The study noted that Hydro One costs reflect contracted prices for low volume individual meter replacements and do not incorporate scale economies that would be expected with bulk purchases. Some of the comparators that have recently completed major meter deployments have shown lower per meter purchase costs, indicating that bulk purchases lend themselves to lower purchase costs.	3.4
3	Hydro One's average labour cost of $122 (excluding materials surcharge and overheads) per meter replaced is higher than the comparator average of $47. The study noted that these costs are higher than the mean of the comparator of the group because they reflect individual replacements rather than mass replacements, and because of the large, mostly low-density nature of its service territory. HONI's customer density is the lowest of the group, 23 times less dense than its closest comparator.	3.4
4	Hydro One's labour resource type used to replace meters aligns with most of the comparator companies. Similar to the comparator companies, HONI does not currently contract out labour for individual replacement of AMI meters; only one of the comparators indicated the use of contract work for AMI meter replacements.	3.3.4
5	Hydro One currently uses smart meter functions similar to the comparators; its future use cases also align with functions which others are seeking in their next generation AMI deployments.	3.3.3

The consideration and/or impacts of these key findings – along with the findings from the meter life testing study and vendor meter life attestation – on Hydro One's investment plan are discussed below.

As detailed in section 3.3.6, above, Trilliant, HONI's primary AMI vendor, attests to a minimum meter service life of 15 years based on its analysis but recommends a conservative approach to replacing metering equipment with a meter replacement cycle that supports up to and including the 15th year of service to balance maximum service life and security of service.

The Hydro Quebec ALT study conducted on HONI meters indicates a less than 15-year service life for the GEN 1 meter population, with approximately 200,000 meters projected to fail between 2020 and 2022 (the 15-year service mark). This, it should be noted, is not inclusive of the tens of thousands of GEN 1 meters that have already failed prior to 2020 discussed in DSP Section 3.2.

The AMI Benchmarking study found Hydro One was among 44% of comparator utilities who had an expected AMI meter service life of 15 years, which represented the mode of the group. The AMI benchmarking study also found Hydro One's meter costs were higher than the comparator group average and noted costs reflected prices for low volume individual meter replacements and did not incorporate scale economies that would be expected with bulk purchases associated with mass deployments. It also found HONI labour costs for meter replacements to be higher than comparators partly due to inherent inefficiencies associated with individual meter replacements compared to mass meter deployments and partly due to longer travel times associated with low customer density. The study also found that Hydro One's future use cases align with functionality which others are seeking in their next generation AMI deployments.

The findings of the above studies, together with observed trends in accelerating meter failures discussed in DSP Section 3.2, support HONI's approach to plan based on an approximately 15-year service life for its AMI 1.0 meters. This approach, detailed in the AMI 2.0 program presented in DSP Section 3.11, D-SR-12, balances the need to maximize the use of existing meters in their lifespan while ensuring reliable and accurate billing services pursuant to HONI's service obligations and minimizing the inherent inefficiencies associated with reactive individual meter replacements.

3.3.8 BILLING AND CALL CENTER COSTS BENCHMARKING - ISG

3.3.8.1 STUDY OVERVIEW

In the OEB's March 7, 2019 decision in the matter of Hydro One's Distribution Rates for 2018 to 2022 (EB-2017-0049), the OEB directed Hydro One to continue its current benchmarking efforts for key programs, including vegetation management, pole replacement, station refurbishment and IT. Additionally, the decision stated that the OEB expects Hydro One to expand its benchmarking to include other capital programs and administrative functions such as billing, call centre and corporate costs. A Request for Proposal (RFP) was initiated to retain an independent expert to undertake a benchmarking study to compare Hydro One's billing and call centre costs to the equivalent costs of an appropriate peer group. As the successful respondent, ISG completed the study focusing specifically on billing and call centre costs in response to the OEB's direction to expand benchmarking studies.

ISG maps Hydro One's Call Centre and Billing services into their Utility Customer Services Industry Framework. The ISG database includes a selection of comparable data in terms of service score, SLA's, volumes, complexity and cost model, which was then compared against data from the selected peer group. The analysis provides benchmarking results including market costs, service design and SLA's, cost trends, volume efforts, improvements or efficiencies planned and Regulatory or unique business requirements or constraints.

ISG's expertise allowed them to identify appropriate candidates from the ISG contractual and costs databases based upon key selection criteria including general service scope, geographic markets, currencies and data validity. ISG then selected the data appropriate for the in-scope benchmarked services including Industry and Service spread/scope, service quality, service volumes, and service complexity and technology. All utilities were chosen from the North American market and service between 800,000 and 3.5 million customers. The peer group includes a mix of in-house, offshore and onshore billing and contact centres, unionized/non-unionized workforce, as well as gas and electric utilities.

ISG applied standard adjustments to both Lines of Business to normalize industry costs including currency exchange and unionization. Details on those adjustments can be found on page 29 of the Hydro One Billing & Call Centre Benchmarking study.

3.3.8.2 SUMMARY OF BENCHMARKING FINDINGS AND RECOMMENDATIONS

The key findings and recommendations found in the Hydro One Billing & Call Centre Benchmarking study are summarized in Tables 12 and 13. The study report can be found in DSP Section 3.3, Attachment 7.

Table 12 - Key Study Findings

#	Key Study Findings	Study Reference
1	Call Centre costs at Hydro One are below the market average. The market average ranges from $18M to $41.4M with an average cost of $26.3M. In 2019, Hydro One Call Centre costs were $24.8M.	Page 13
2	Billing costs at Hydro One are towards the lower end of the market range. The market ranges from $4.8M to $8.1M with an average cost of $7.1M. In 2019, Hydro One Billing costs were $5.4M.	Page 14
3	Total Call Centre and Billing spend at Hydro One is 9% below the market average. The market ranges from $22.8M to $49.5M with an average cost of $33.4M. Hydro One has reduced costs approximately 20% since repatriating services while meeting the OEB's Customer Focus (Service Quality and Customer Satisfaction) Metrics on the Consolidated Scorecard of Electricity Distributors.	Page 15
4	Customer Service Representatives at Hydro One is below the peer group average. The market ranges from 125-505 with an average of 270.6 CSRs (Hydro One = 242 CSRs). Additionally, the cost per CSR at Hydro One is slightly below the peer group average. The market ranges from $80k to $120k with an average of $100k (Hydro One=$97.52K).	Pages 18-19
5	The number of Billing FTEs at Hydro One is well below the peer group average. The market ranges from 60 to 100 FTEs with an average of 77.4 FTEs. (Hydro One=58.73 FTEs). Hydro One is already using RPA Billing Operations, which contributes to its low FTE count.	Page 20

Table 13 - Recommendations

#	Recommendations	Study Reference
1	Speech Assessment – Each additional 1% of IVR Containment can result in a Benefit (savings) of $330,000 - $400,000 per year (calculated from three U.S. utilities and converted to Canadian dollars). Estimated Capital Investment ranges from $10M-$15M for NLU speech.	Page 23
2	Many utilities today are optimizing the IVR with Natural Language and adding additional digital technologies to the Call Centre such as Chat and Chat Bot Technology to reduce live agent call handling. Hydro One should entertain a chat & chat bot pilot project in the Call Centre. Each additional 1% of call reduction as a result of Chat & Chat Bot Technology can result in a Benefit (Savings) of $330,000 - $400,000 per year. Recent results at utilities demonstrate a call reduction of 1% - 5% when using chat & chat bot technology. Estimated Capital investment ranges from $2.5m - $6m	Page 24
3	Hydro One should entertain an RPA pilot in the Call Centre for customer authentication (Billing is already using it) for automating repetitive business processes. A reduction in work of 10% due to a pilot project can result in a Benefit (Savings) of $450,000 - $600,000 per year. Estimated Capital investment ranges from $1m - $2m.	Page 25
4	Hydro One should entertain a voice biometric option in the Call Centre to reduce time associated with customer authentication. Other industries (banking, finance, and healthcare) are experiencing a 50-second reduction in AHT by using voice biometrics to authenticate an inbound customer call. Assuming a conservative 50% of inbound calls using voice biometrics, total Call Centre costs could be reduced by up to 5%, or $1.5m per year. Estimated Capital investment ranges from $3m - $5m.	Page 26

The impacts of the study report on Hydro One's investment plan and processes are discussed below for each recommendation.

According to the results in ISG's Benchmarking Study, Hydro One's costs related to the Call Centre and Billing Operations are lower than the peer group. As such, no integration into the business plan was required.

The Study recommended Hydro One entertain the use of Chat & Chat Bot technology within the Call Centre as an area of potential improvement. The Study also recommended the use of RPA in the Call Centre for customer authentication for repetitive business processes. Both Chat & Chat Bot technology as well as the use of RPA in the Call Centre had been previously investigated with pilots underway prior to the findings of this Benchmarking Study.

The Study recommended Hydro One should entertain the use of Natural Language Understanding (NLU) to increase Interactive Voice Response (IVR) containment. The Study also recommended the use of Voice Biometrics in the Call Centre to reduce time associated with customer authentication. These findings were not integrated into the current budget. Hydro One will undertake a cost benefit assessment to determine if the recommendations related to Speech Assessment and Voice Biometrics should be included in subsequent rate filings.

The following attachment(s) are provided as part of this section:

- Attachment 1 – Guidehouse and First Quartile Distribution Poles and Substations Benchmarking
- Attachment 2 – CNUC Hydro One Vegetation Management Study
- Attachment 3 – ClearPath OCP First Cycle Performance Assessment
- Attachment 4 – Trilliant Correspondence on Expected Service Life for Meters
- Attachment 5 – Hydro Quebec Accelerated Life Testing of Meters
- Attachment 6 – Guidehouse and First Quartile AMI Benchmarking
- Attachment 7 – ISG Billing and Call Center Benchmarking
- Attachment 8 – Smart Meter Efficiency Report

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Distribution Poles and Substations Benchmarking

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December 16, 2020

Table of Contents &

Executive Summary .... 3 !
1 Introduction .... 4 !
1.1 Study Objectives .... 4 !
1.2 Overview of Approach .... 4 !
1.3 Content of Report .... 4 !
2 Benchmarking Process .... 5 !
2.1 Overview .... 5 !
2.2 Information Collected .... 6 !
2.3 Comparator Group Selection .... 7 !
2.4 Normalizing Factors .... 8 !
3 Benchmarking Observations .... 8 !
3.1 Distribution Poles .... 9 !
3.1.1 Service Territory .... 9 !
3.1.2 Pole Refurbishment .... 10 !
3.1.3 Pole Inspections .... 10 !
3.1.4 Pole Replacements .... 12 !
3.2 Distribution Substations .... 18 !
3.2.1 Service Territory .... 18 !
3.2.2 Costs for Substation Refurbishment and Transformer Replacement .... 23 !

Executive Summary

The consortium of Guidehouse Canada Ltd. (Guidehouse) and First Quartile Consulting (1QC or First Quartile) has conducted a benchmarking study for Hydro One Networks Inc. (Hydro One or HONI) regarding distribution pole replacements and distribution substation refurbishments. This report provides an overview of the approach taken by Guidehouse and 1QC (including the processes of selecting and recruiting utilities to participate in the study, assembling appropriate performance metrics, and gathering / analysing the data) and results of the study, which provide insights into both the costs incurred by Hydro One and the practices used for the execution of pole replacement and substation refurbishment. Primary findings from the study for both the pole replacement and station refurbishment activities are highlighted below.

Pole Replacement

- Hydro One's service territory covers more surface area than the average comparator and includes a significant proportion of rural and remote locations that can be difficult or require specialized equipment and procedures to access.
- In 2020, Hydro One initiated an annual standardized pole refurbishment program and a test and treat program that are similar to those of comparator utilities.
- Hydro One utilizes both visual and data dependent sound and bore inspection methods, with inspection rates that are lower than comparators.
- Hydro One's distribution poles are on average older than the comparator group.
- Hydro One replaces poles based upon condition and has a higher pole replacement rate (including poles replaced upon failure) as compared with comparators.
- Hydro One's pole replacement costs are comparable to the mean of the comparator group.

Substation Refurbishment

- Hydro One's distribution substation assets service a higher percentage of rural territory versus comparators.
- Hydro One's distribution substations have higher average peak loading (as a percentage of nameplate capacity) than comparators, and in contrast with comparators are primarily comprised of single transformers that are sufficient for the population that they serve.
- Hydro One has lower than average costs to replace power transformers as they are primarily comprised of smaller transformers.
- Hydro One has lower than average costs for distribution substation refurbishments on a per transformer basis.
- Hydro One has recently focused more on component-centric projects, which aligns with the most common approach to station refurbishment among comparator utilities
- Hydro One has also introduced a lower cost unfenced pad mount transformer solution for replacement of smaller substations (where feasible), which most other utilities have not considered.

1 Introduction)

1.1 Study Objectives

The objective of the study was to quantify and evaluate, through benchmarking comparison and analysis, the unit costs of Hydro One's Distribution pole replacement and Distribution substation refurbishment activities. Normalization was undertaken to make appropriate comparisons with other utilities whose circumstances aren't identical to those facing Hydro One. This was done in the least complex way possible to create accurate, fair comparisons.

1.2 Overview of Approach

The scope of work included two workstreams: a review of the costs for pole replacements, and a review of the costs for substation refurbishment. The approach to each stream was the same, consisting of steps for comparator selection, metric development, data collection, and analysis. In both cases, the work leveraged the annual First Quartile Transmission & Distribution benchmarking program, with its existing participant group and underlying database, augmented by data gathered from additional comparator utilities.

In conducting the study, we gathered data from Hydro One and comparator utilities, validated and normalized the various data elements, and created a series of graphs and tables of the relevant demographics and performance metrics. This assembly of the basic dataset was followed by analysis of the results to develop findings and observations about Hydro One's relative cost performance. A minimal level of practice information (e.g. cycle times for inspections, approach to refurbishments) was also included in the data collection and analysis, to help in understanding the cost outcomes.

1.3 Content of Report

This report is organized into two main sections:

Section 2: Benchmarking process, providing an overview of the process used, information collected, comparator group selected, and normalizing factors used.

Section 3: Benchmarking observations, which summarizes the findings from the study. There are sub-sections for distribution poles and substations, with a summary of the demographics, brief description of work processes, and cost results.

2 Benchmarking Process

2.1 Overview

The study was conducted in a series of steps to define, gather, and analyze data from a broad group of utilities for comparison with Hydro One's activities and results. Figure 1 below provides a conceptual view of the steps in the project. Some of the steps were conducted prior to the launch of the 2020 First Quartile annual study, so that specific data elements needed for this project could be incorporated into the annual study and the associated data collection and validation process.

Figure One – Project Overview

- **Project Kickoff and Initialization** – This stage was designed to determine the characteristics of companies to include in the comparator group, the demographic data that would be helpful, and the metrics for making the comparisons.
- **Quantitative Analysis**
  - Data Collection and Normalization – Gathering data through a detailed questionnaire directly completed by participating utilities, followed by normalization and data validation. In a few cases, follow-up discussions were held with participating utilities to better understand their questionnaire responses and their underlying operations.
  - Comparative Findings – creating a comparative summary with charts and graphs comparing results
- **Post Analysis** – Review the results, draw out relevant observations about Hydro One demographics, performance, and practices, and assemble them into a summary report

2.2 Information Collected

There were three primary types of data collected for the study – demographics, practice information, and cost performance data. Demographic data serves both to highlight the circumstances facing each utility and as normalizing factors for comparing utilities with different characteristics. Practice information helps explain some of the cost differences, as well as show how the different utilities have chosen to address their unique circumstances. The purpose of the first two types of data is to enable a proper understanding of the third type of data, i.e., the cost of conducting the work activities that are the main subject of the study. Figure 2 provides an overview of the types of information gathered in each category.

Figure 2 – Information Collected for the Project

Distribution Poles Information Collected *

Demographic Information	Practice Information	Cost Performance Data
• Service territory square miles/km • Number of in-service poles by material type and age profile	• Expected Service Life for different pole types • Inspection methods, trigger ages, time cycles, and outcomes • Average months to complete non-urgent pole inspection recommendations • Refurbishment methods used • Reasons for pole replacements	• 2019 pole inspection volumes and costs • 2019 results of inspections • 2019 pole refurbishment volumes and costs (3-yr avg. for HONI) • 2015 to 2019 program pole replacement volumes • 2019 emergency pole replacement volumes • 2020-2024 planned replacement and refurbishment volumes

Distribution Substations Information Collected *

Demographic Information	Practice Information	Cost Performance Data
• Service territory square miles/km • Number of distribution substations by size (# power transformers) and service territory density served (urban vs. suburban vs. rural) • Number of distribution power transformers by high side and low side voltage • Current in-service age profiles of major substation components • Average power transformer loading % at coincident peak for past 12 months	• Expected Service Life for major substation components • 2015 to 2024 number of actual and planned refurbishment projects by approach	• Data on recently completed distribution substation refurbishments including: • Refurbished substation demographics • Refurbishment project type (component-focused vs. station-centric vs. full station rebuild) and high-level work scope • Detail on major components replaced/installed • Total project costs and costs associated with major component installations

2.3 Comparator Group Selection

Every benchmarking study requires a comparison cohort, with the goal to assemble a representative group that reflects the industry. A broad comparator group enables comparisons of outcomes, and also enables a look at different demographics and practices that have influence on the outcomes. To achieve a broad panel of comparators, Guidehouse and First Quartile defined demographic criteria for evaluating comparators who would be appropriate for this study, including size (e.g. number of poles, km of line, circuits, number of substations), system age, and territory density.

The next step in comparator selection involved recruiting utilities to participate. This started with the utilities already involved in the annual First Quartile benchmarking study, which were expanded through approaching a number of other Canadian and U.S. utilities who met the basic demographic criteria as described above. In all, 36 utilities were approached and invited to participate, including:

- 9 Canadian Utilities
  - Large provincial utilities from across Canada
  - Local distribution companies in Ontario
- 27 Large U.S. Utilities

A total of 27 utilities responded to at least some portion of the data request. Some of them only responded to the Distribution poles part of the questionnaire, some only to the substations portion, and some to both. The utilities that chose not to participate cited various reasons for not participating:

- Lack of sufficient data
- Insufficient resources
- Competing priorities

Figure 3 below shows the utilities represented in the comparison panel, with each color-coded to show which types of data they provided. As can be seen, there is a mix of U.S. and Canadian utilities. They represent the industry from the standpoint of experiencing various weather patterns, having both low-density and higher-density portions of service territory, and having both similar and different regulatory circumstances from Hydro One.

Figure 3 – Utilities in the Comparator Group !

2.4 Normalizing Factors

Normalization was done to enable fair comparisons of utilities with different characteristics. A straightforward normalization factor is the currency conversion from US dollar to the Canadian dollar.[1] Other normalization factors address scale – e.g. the number of poles or substations, the MVA of capacity at substations, the number of transformers at a station. In the end, unit costs were derived from the appropriate normalizing factors – so the unit cost for pole replacement is measured as the cost per pole replaced, and similarly for substations, the unit costs are measured on a per-transformer basis.

3 Benchmarking Observations

This section outlines the overall findings of the study as a series of observations in two sub-sections (for poles and substations). Each sub-section sets out observations about the demographics of the HONI system and findings about the costs of work. Each observation is supported by a figure in which Hydro One is highlighted by a red arrow ( )

[1] Exchange rate used is 1.3269 CAD to USD. Source: U.S. Federal Reserve January 2, 2020. https://www.federalreserve.gov/releases/g5a/current/

3.1 Distribution Poles

3.1.1 Service Territory

Hydro One has a vast service territory that is much larger than even the nearest comparator in size. It includes large portions of remote and rural territory with difficult to access locations, some of which require specialized equipment and procedures to safely service assets. Hydro One's territory is also the least densely populated relative to the comparator group. Figures 4 and 5 below show comparisons of Hydro One service territory to comparator utilities by customers per distribution circuit-km and customers per square km.

Figure 4 – Density: Customers per Distribution Circuit km

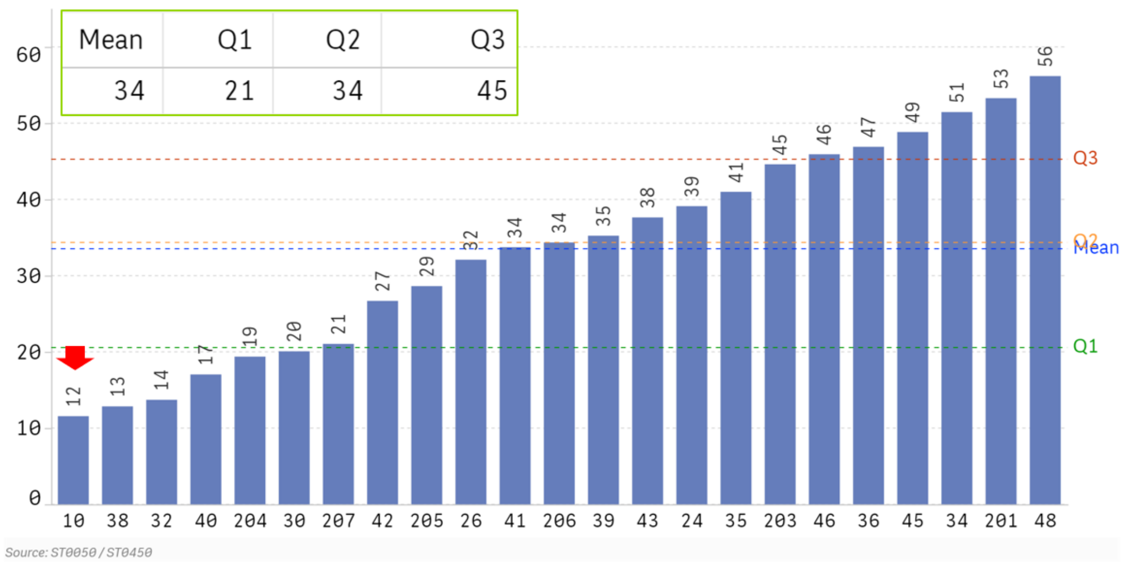
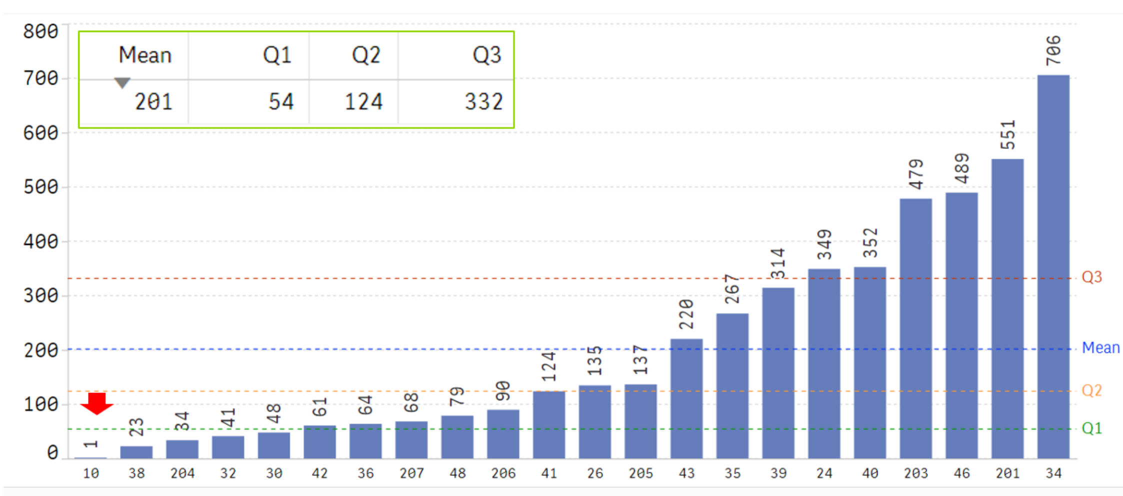


Figure 5 – Density: Customers per Square km !

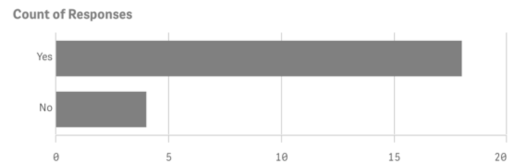


3.1.2 Pole Refurbishment

Hydro One conducts both an annual standardized pole refurbishment program initiated in 2020 and a test and treat program initiated in 2020. While only recently begun, HONI's program is much like those of other utilities, with a decision-making framework that prioritizes pole replacements based on condition data (in addition to replacement drivers related to failure, emergency and other external factors). As shown in Figure 6, 18 of 22 responding companies had a formal refurbishment program in place during 2019, primarily utilizing a combination of truss/stubbing and wrap/retreatment rods.

Figure 6 – Pole Refurbishment Process

* Note that the survey focused on 2019 data and hence HONI's response is indicated as "No" for pole refurbishment practice – HONI has initiated its pole refurbishment program as of 2020



	10	19	24	25	26	30	32	34	35	36	39	40	41	42	43	45	46	203	204	205	206	207
Yes	-	♦	-	♦	-	-	♦	♦	♦	♦	♦	♦	♦	♦	♦	♦	♦	♦	♦	♦	♦	♦
No	♦	-	♦	-	♦	♦	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: DP3500

3.1.3 Pole Inspections

Hydro One's pole inspection program utilizes both visual and data-dependent sound and bore inspection methods, with the sound and bore methods introduced in 2020. The more intrusive sound and bore inspections involve an external damage assessment, sounding, excavation, removal of surface level rotted wood, and measuring shell thickness and circumference of the pole.

HONI has been conducting visual inspections every 3-4 years, and plans to continue that practice. The sound and bore inspections introduced through the new test and treat program will be conducted on a 15-year cycle. Other utilities primarily focus on sound and bore inspections, which they conduct on a 10-year cycle typically. Figure 7 shows the planned cycle times for inspections of various types:

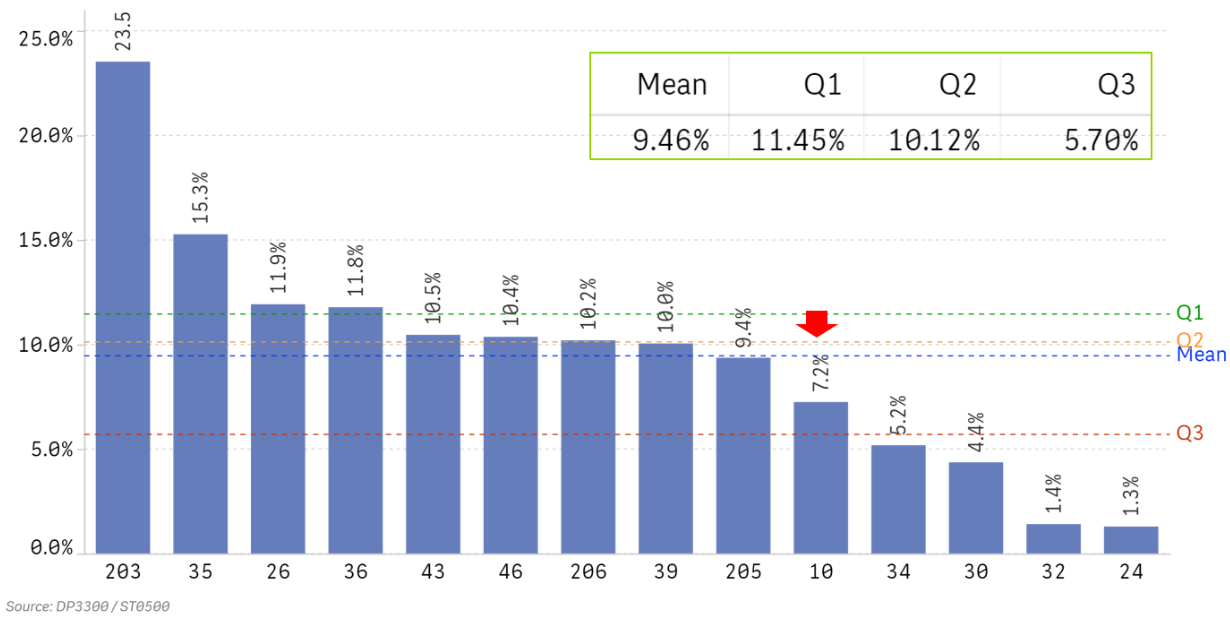
Figure 7 – Cycle Time (in Years) for Inspection Process of Distribution Wood Poles

AN = "As Needed"

	10	19	24	25	26	30	32	34	35	36	39	40	41	42	43	45	46	203	204	205	206	207
Patrol	-	-	10	10	2	10	-	10	8	1	99	10	-	-	10	-	10	5	-	-	-	-
Visual	3	10	10	10	10	10	-	10	8	10	10	10	10	10	10	10	10	5	12	10	8	12
Sound	15	10	10	10	10	10	-	10	8	10	10	10	10	10	10	10	10	10	12	10	8	12
Bore	15	10	10	10	10	10	-	10	8	10	10	10	10	10	10	10	10	10	12	10	8	12
Excavation	-	10	10	10	-	10	-	10	8	10	10	10	10	10	10	10	10	10	-	10	8	-
Other	-	-	10	10	-	-	AN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ultrasonic	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Over time, utilities work to meet their planned cycle lengths for inspections as indicated in Figure 7 above. However, there are fluctuations in the actual number of poles inspected each year. Figure 8 shows the percentage of poles actually inspected by each comparator company during 2019. As can be seen from the figure, most but not all the companies achieved their target number of inspections during that year. For clarity, a 10-year inspection cycle would require that 10% of poles are inspected annually, and a 15-year cycle would require approximately 6.7% of the poles inspected annually. Hydro One's inspection rate was lower than the mean during 2019.

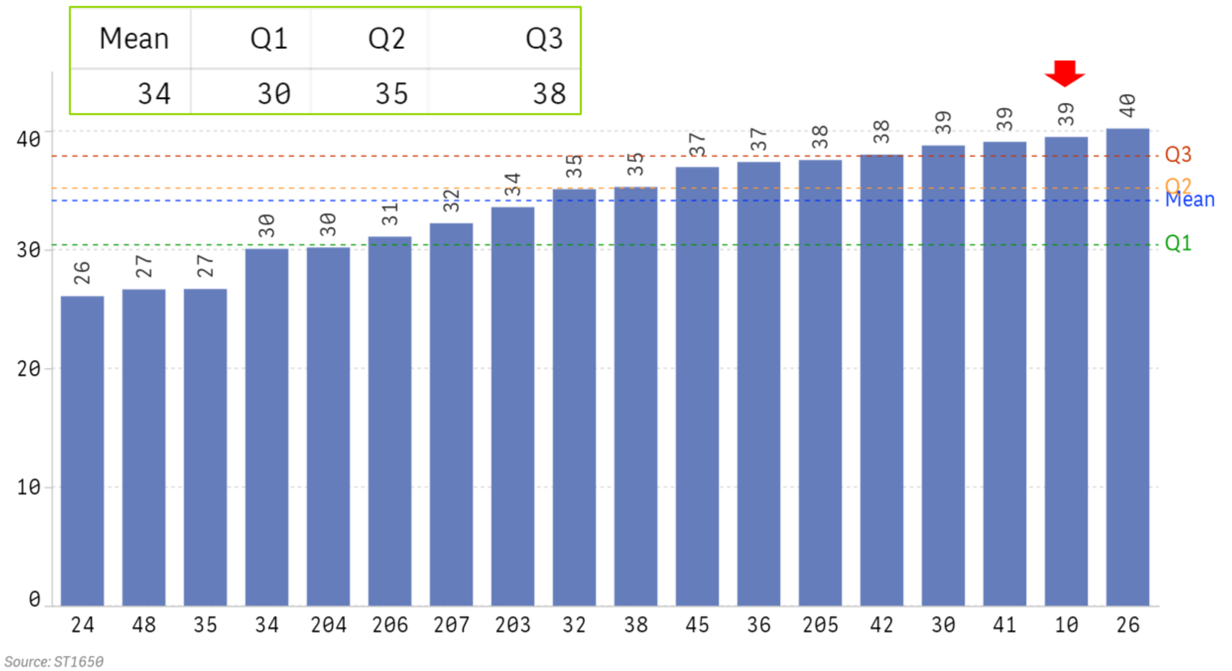
Figure 8 – Percentage of In-Service Poles Inspected in 2019



3.1.4 Pole Replacements

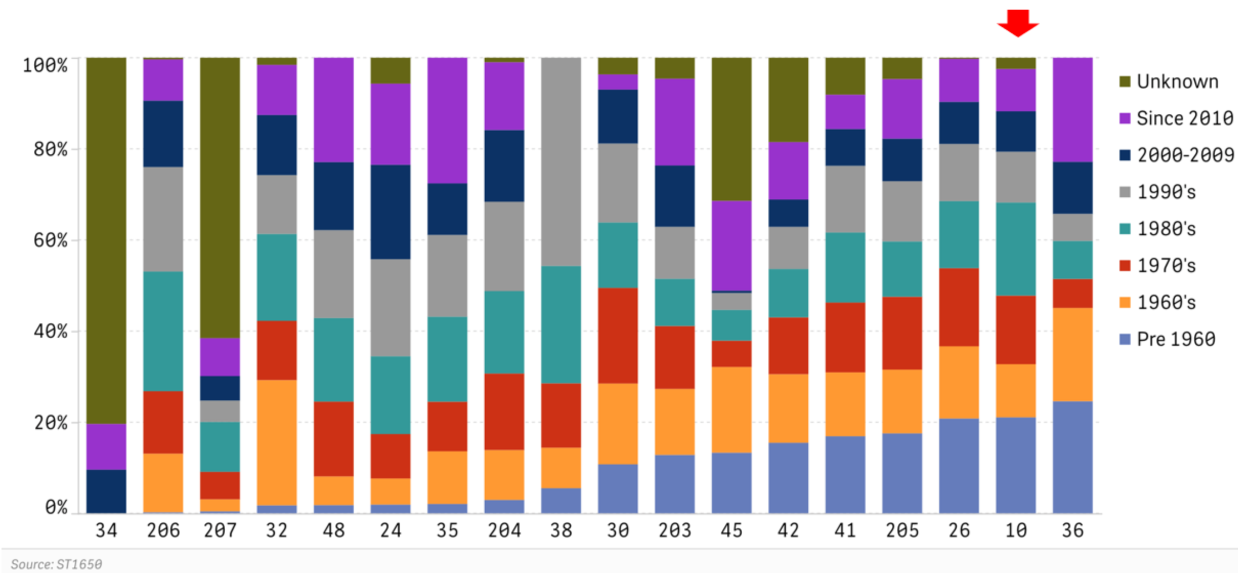
One variable that helps in understanding the replacement rates for wood distribution poles is the age of the pole inventory. In this case, the average age of HONI's poles is the second highest within the comparison panel at 39 years, compared to the group average of 34 years. Figure 9 shows this average age pattern for the comparison group.

Figure 9 – Average Age of Distribution Wood Poles



Understanding the distribution of the ages of the individual poles is also helpful. Because different utilities experienced different growth periods over their history, they have different patterns of when they installed large numbers of wood poles. Figure 10 shows the distribution of when poles were put in-service by decade for each company in the group. In addition to having a high average age, HONI's pole inventory features the second highest percentage of poles installed over 60 years ago (pre-1960), and approximately half of its poles were installed in the 1970s or earlier.

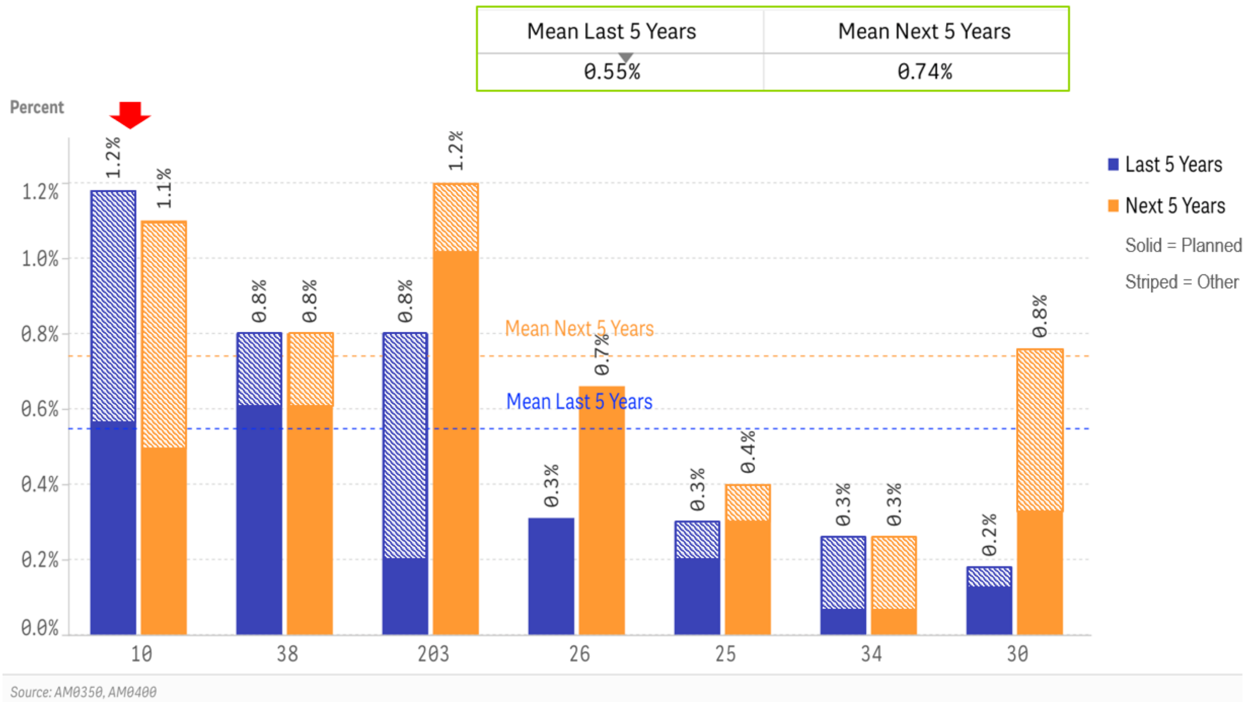
Figure 10 -- Percentage of Current In-Service Distribution and Secondary Wood Poles Installed by Decade



This study asked each of the participating utilities to provide the number of poles it had replaced in the past 5 years and expects to replace over the next 5 years across all programs for any reason including failures due to trouble or storms.

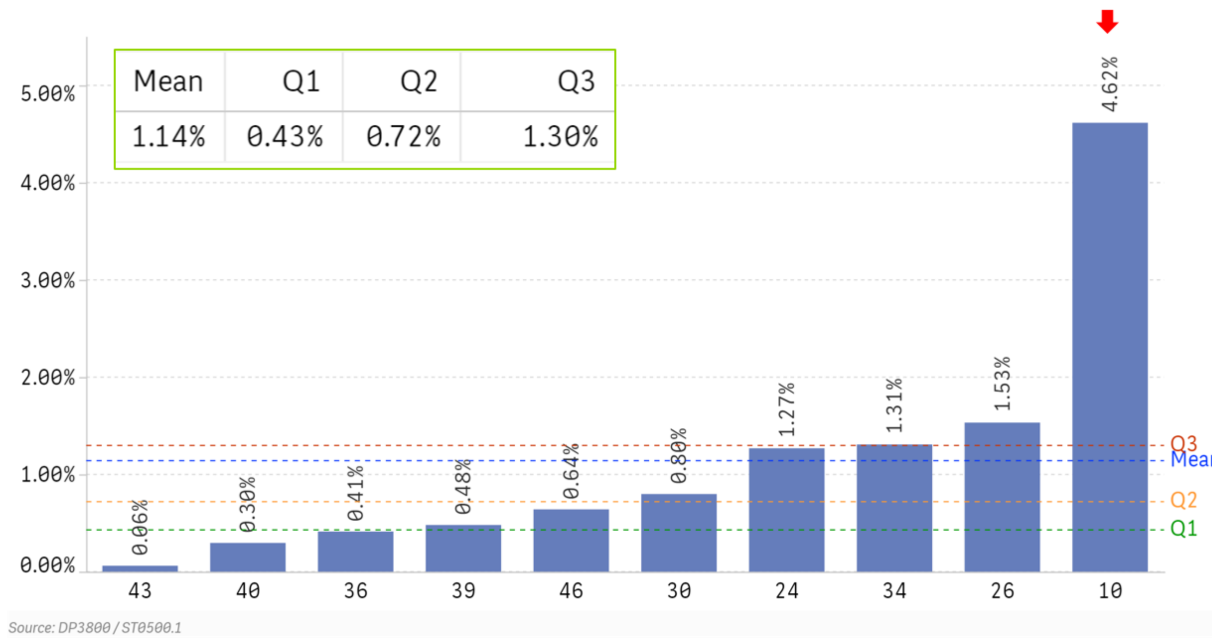
As shown in Figure 11 below, Hydro One had the highest replacement rate over the last 5 years, and has the second highest expected replacement rate over the next 5 years. It is important to note that these figures include the number of poles that have failed or are projected to fail under trouble or during storms. Given that the average age of poles for utilities in the group is 34 years or older, the average utility is replacing its poles at a rate that suggests an expectation of an extended life-span.

Figure 11 – Percentage of Distribution Wood Poles Replaced and Planned or Projected to be Replaced Annually !



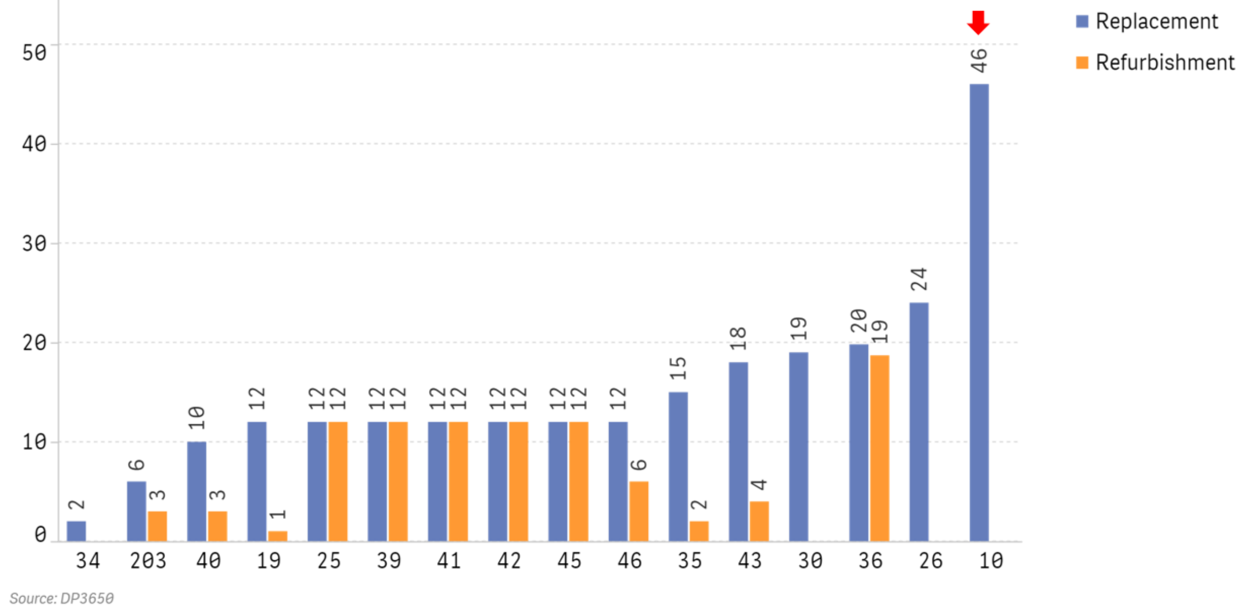
When a determination is made that a pole should be replaced, it is typically placed on a list of poles awaiting replacement, so that the work can be prioritized and scheduled in the most cost-effective way possible. In Hydro One's case, its current list of poles identified as requiring replacement represents 4.62% of its entire pole inventory, as shown in Figure 12. Any other poles that are determined to require replacement through inspections in the next five years will be in addition to the ones already identified/planned.

Figure 12 -- Percent of Total In-Service Poles on List for Replacement at End of 2019



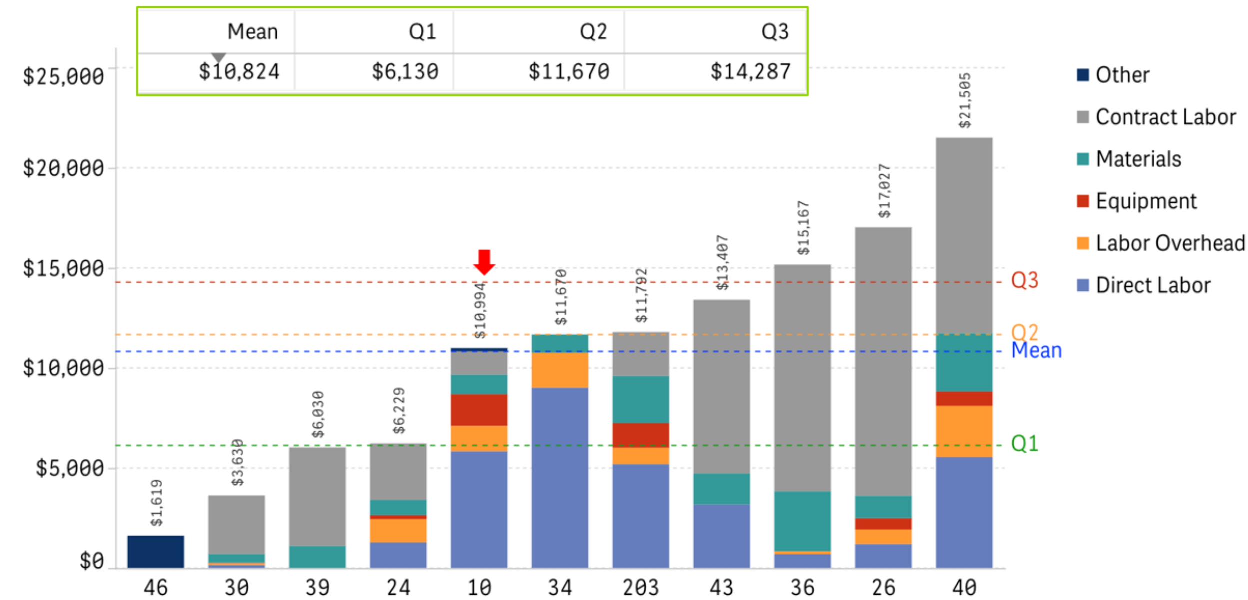
A secondary aspect of planning is the time lag from a failed pole inspection to actual refurbishment or replacement. Most companies try to keep that time under one year. Figure 13 shows the actual time from identification until treatment/replacement.

Figure 13 -- Months to Replace or Refurbish a Pole After a Failed Inspection



With respect to pole replacements, this study aims to compare Hydro One's replacement costs with the costs of comparator utilities. Figure 14 below shows HONI's 3-year average (2018-2020) replacement costs and the comparators' replacement costs for 2019. Two observations are notable for Hydro One – first, its costs are essentially at the mean of the group, and below the median (Q2) value; and second, HONI is one of a few companies in the group that execute the majority of pole replacements with in-house staff.

Figure 14 -- Spending on Pole Replacement per Pole Replaced



Source: DP3850 / DP3700.1

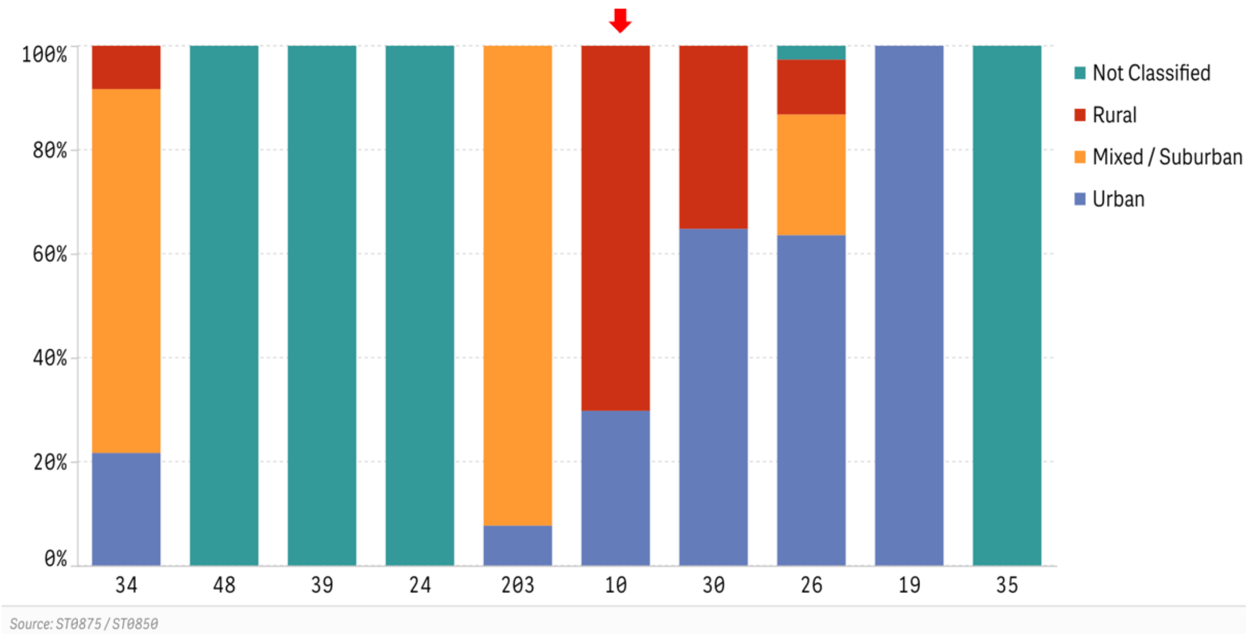
A final observation is that the industry as represented by the comparator group appears to be replacing or refurbishing its poles at a rate that is insufficient to sustain it over the long term. The stated expected service life for wood poles for most utilities is an average of 47 years. The average wood pole is 34 years old, with many older than that, indicating that in 13 years, the average pole will reach its expected lifespan. The comparator utilities' actions are more consistent with an expected 75-100 year lifespan for the average pole, yet it is clear to industry observers that achieving this lifespan is unlikely. The gap between the expected service life for poles and the current replacement rates is cause for concern for the industry.

3.2 Distribution Substations

3.2.1 Service Territory

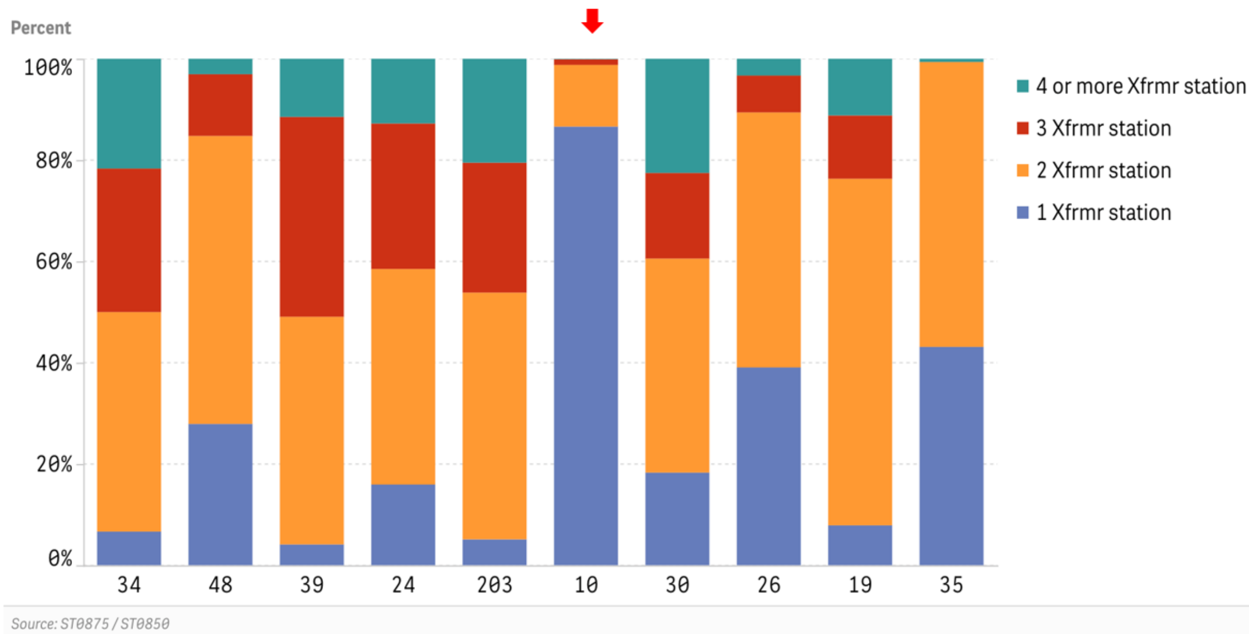
Figure 15 below shows the basic characterization of the comparator companies' service territories. For Hydro One, its service territory is characterized by a significant proportion (70%) of rural areas with a very low density of population. Consequently, HONI's distribution system is designed to meet the unique needs of a service territory that is characterized by long lines and relatively small substations to serve small numbers of local customers.

Figure 15 – Distribution Substations In-Service, By Region



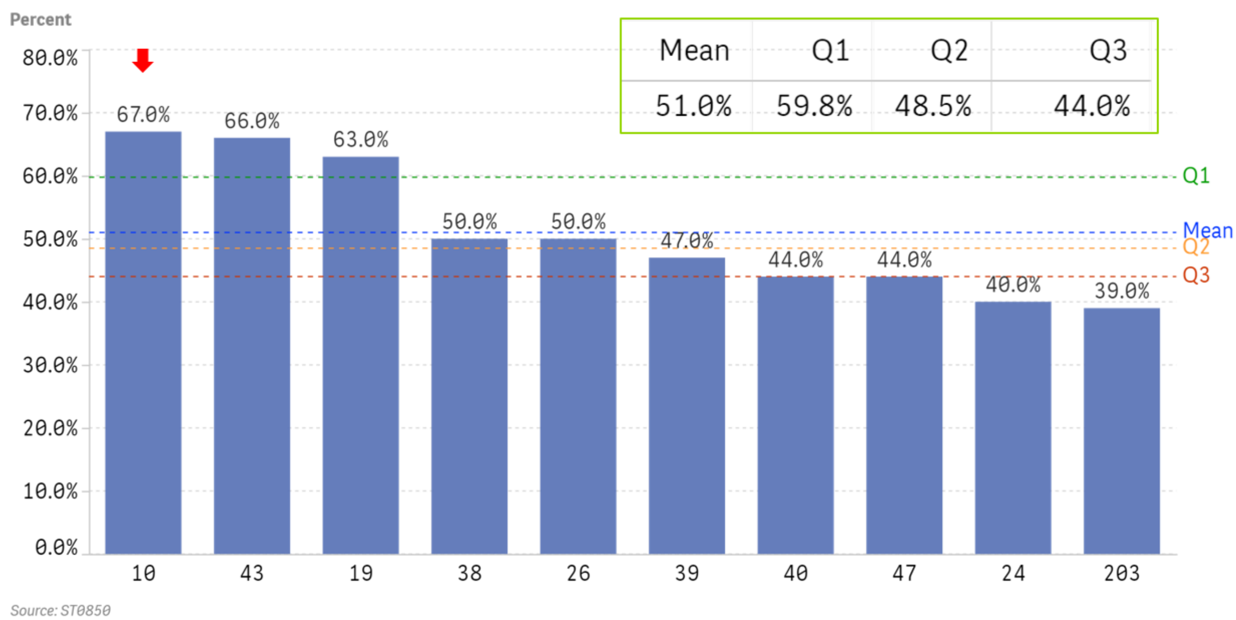
Hydro One's distribution substations, which are scattered across a large and thinly populated territory, generally do not warrant more than one transformer at most of the stations. Figure 16 shows that Hydro One has by far the highest percentage of single-transformer stations in the comparator group.

Figure 16 -- Distribution Substations In Service, By Number of Transformers



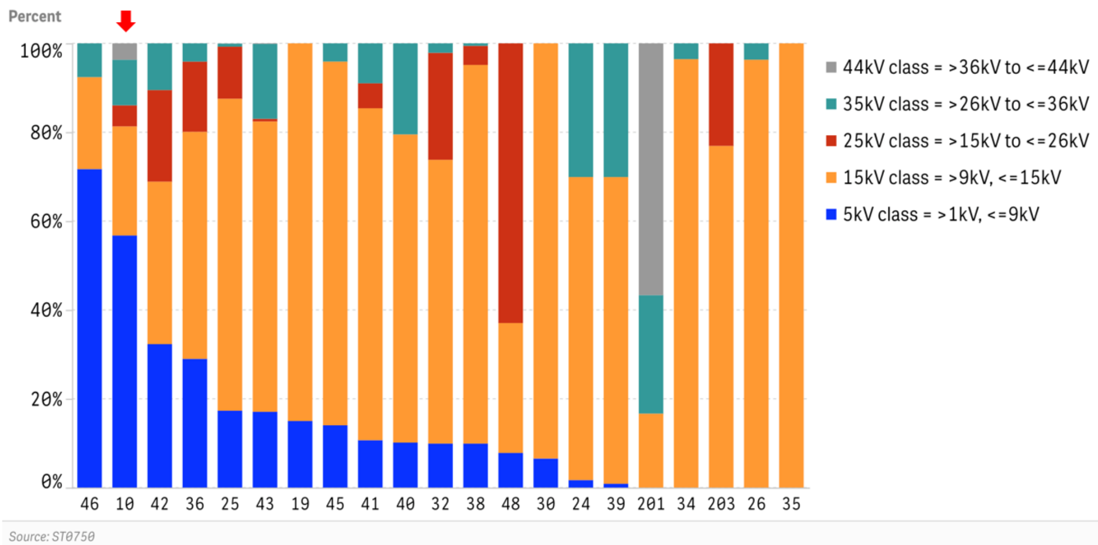
With a large number of small single-transformer substations in service across Hydro One's system, the average loading of those transformers is higher than average, as would be expected. Hydro One's Distribution substation transformers have the highest peak loading (as a percentage of nameplate rating) among the comparison group, as shown in Figure 17 below.

Figure 17 -- Average Substation Transformer Loading at Peak: Distribution



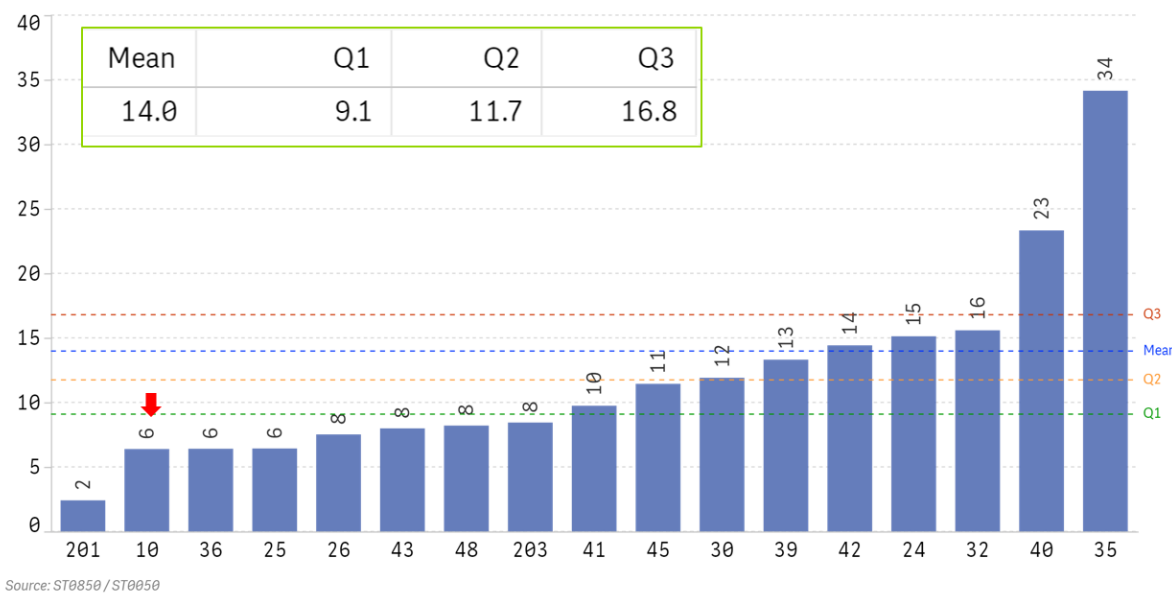
Along with the single-transformer design of most of its stations, HONI also uses lower voltages than many other comparators. Figure 18 below shows that HONI is one of two companies in the comparator group with the majority of its substation transformer banks in the 5 kV class (between 5 and 9 kV), while the majority of transformers on the comparators' systems are in the 15 kV class (between 9 and 15 kV).

Figure 18 -- Distribution Substation Transformer Banks by Voltage Level



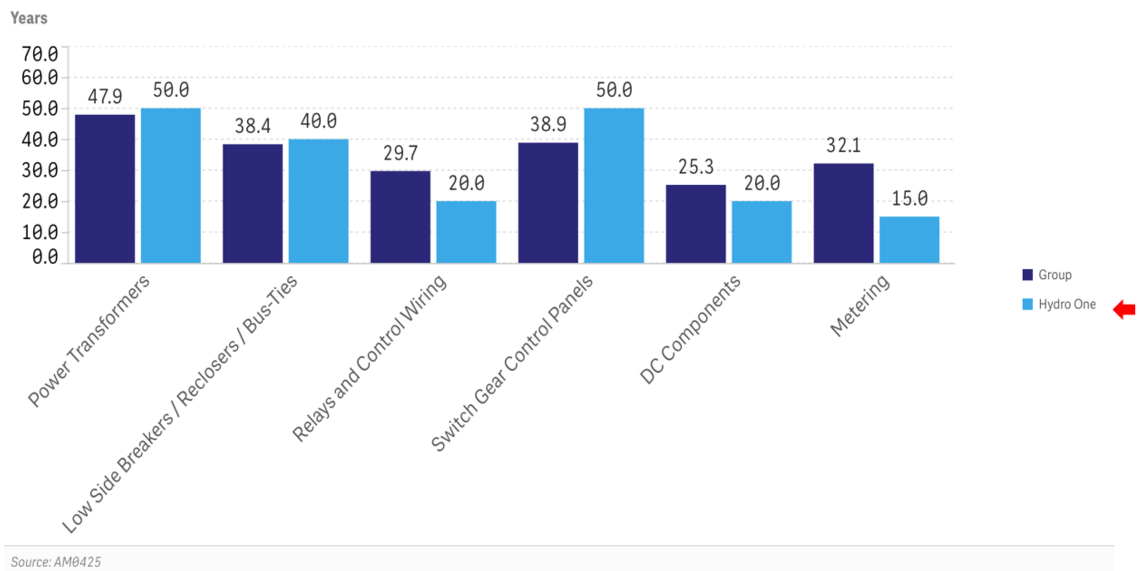
With substations and distribution lines that serve relatively few customers across a vast territory, Hydro One's distribution substations have relatively small transformation capacity that is on average lower than that of comparators. Figure 19 below shows that Hydro One is able to serve its customer base with smaller stations and transformers.

Figure 19 – Installed Distribution MVA Capacity per 1000 Customers



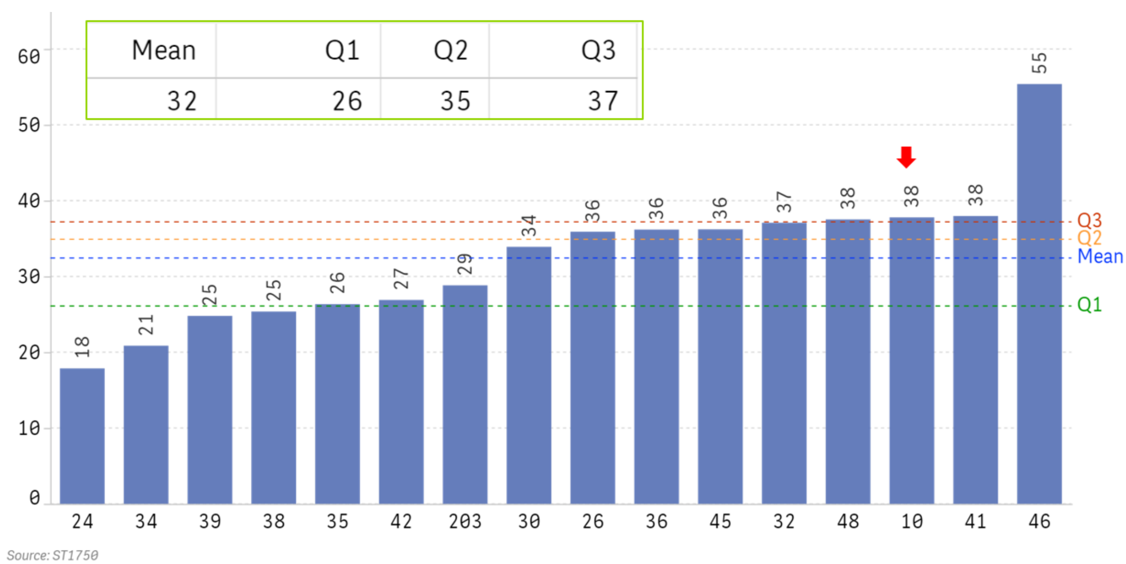
HONI's distribution substation assets have a longer expected life than the comparator companies. Hydro One plans for slightly longer life for most types of assets, including transformers that typically drive the larger investment and refurbishment decisions. Figure 20 shows this relationship.

Figure 20 -- Average Expected Service Life for Distribution Substation Equipment



While the expected life of its distribution substation assets is generally longer, the average age of Hydro One's distribution station power transformers (38 years) is among the highest out of the comparator group (which reflects an average age of 32 years). Figure 21 shows the age statistics.

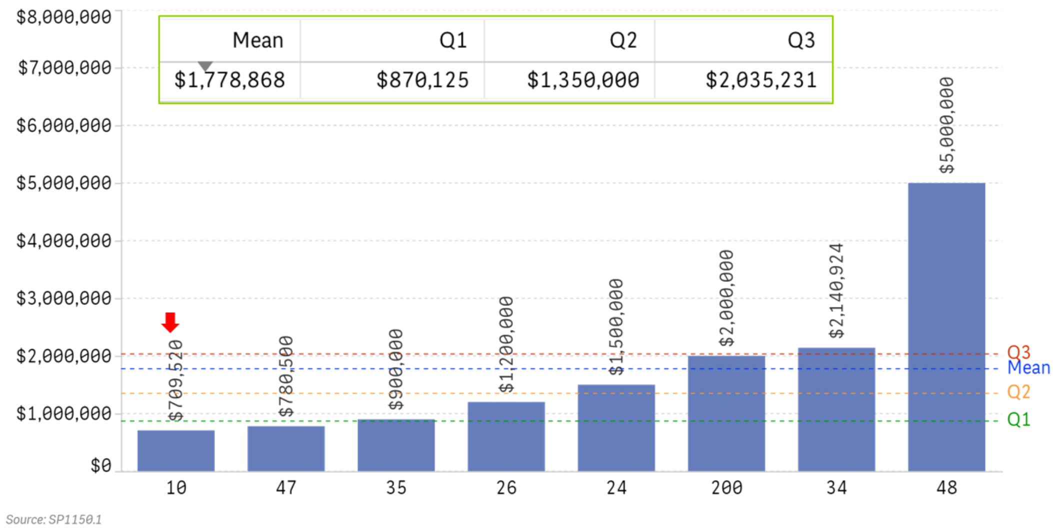
Figure 21 -- Average Age of Distribution Substation Power Transformers



3.2.2 Costs for Substation Refurbishment and Transformer Replacement

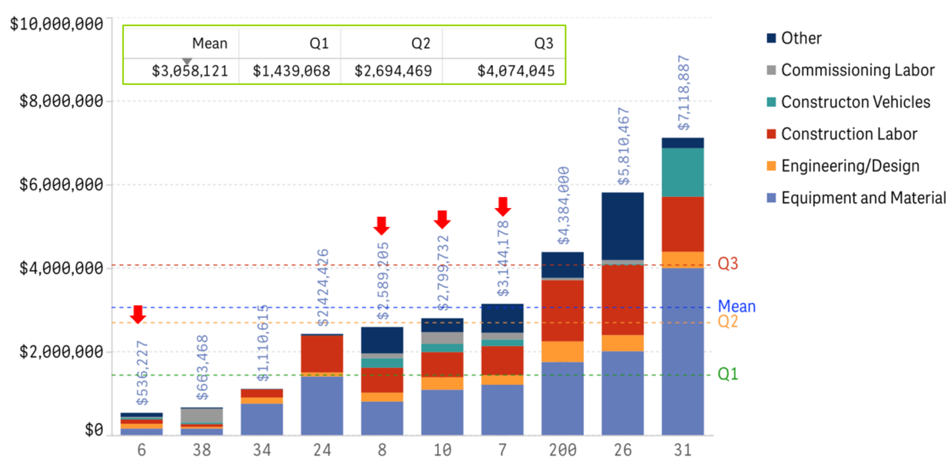
Hydro One has lower than average costs to replace substation transformers. HONI's average cost to replace power transformers is an all in cost of $709K, and is lower than the mean of $1.8M ($1.3M excluding company 48 outlier). The lower costs are partially attributable to greater use of smaller transformers – a higher percentage of 5 kV class (1-9 kV) transformers within HONI's service territory versus the comparator group, who have the majority of power transformers within the 15 kV class (9-15 kV), as described above. Figure 22 shows the cost range within the comparison group.

Figure 22 -- Average Per-Unit Cost to Replace Power Transformers and Associated Equipment



Hydro One has lower than average costs for distribution substation refurbishments on a per transformer basis. These costs represent all equipment, labour and overhead costs for station refurbishment normalized per transformer. HONI averaged $2.4M (across 4 representative refurbishment projects) compared to the mean of $3.1M. In conducting the comparisons, costs were normalized per transformer to be consistent with the single-transformer configuration of most of HONI's distribution substations.

Figure 23 -- Refurbishment Project Cost per Substation Power Transformer In Service at Refurbished Substation !



Recently, Hydro One has focused more on component-centric projects, which is true of most other comparator companies, as shown in Figure 24. Prior to 2015, Hydro One focused on full rebuilds and station-centric refurbishments. In addition to the shift to more component-based projects, HONI has also introduced a lower cost unfenced pad mount transformer solution for smaller substations. Most of the comparators have not considered this option (2 of 12 have such solutions). Where feasible, this solution is more cost efficient in HONI's experience relative to a full station rebuild. Over the next 5 years, HONI expects to continue the trend of increased component-focused projects~~,~~ as shown below in Figure 25.

Figure 24 -- Distribution Substation Refurbishments Completed per Distribution Substation: 2015 through 2019

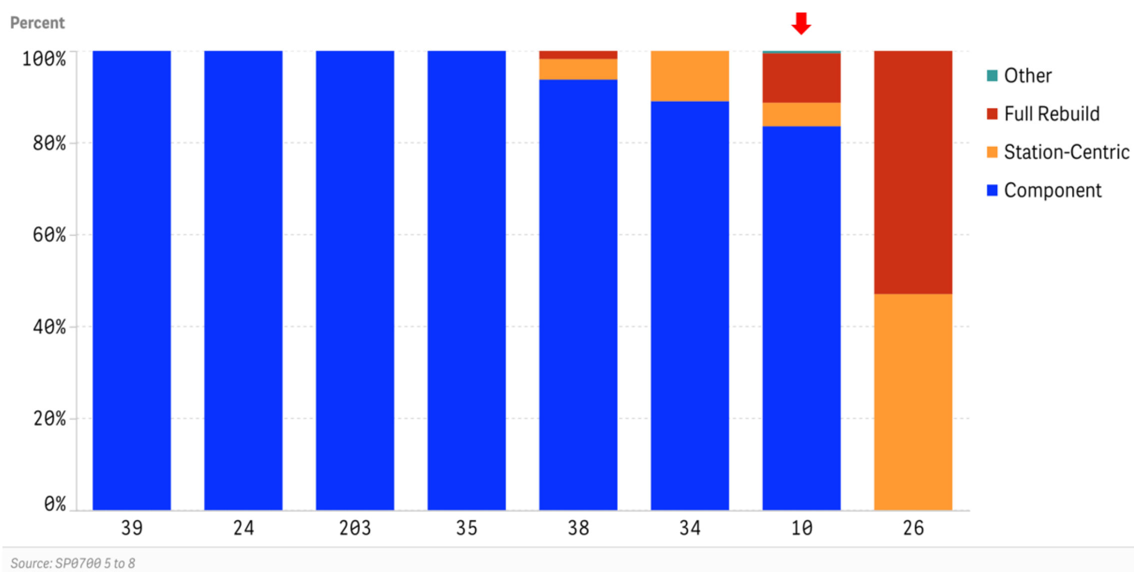
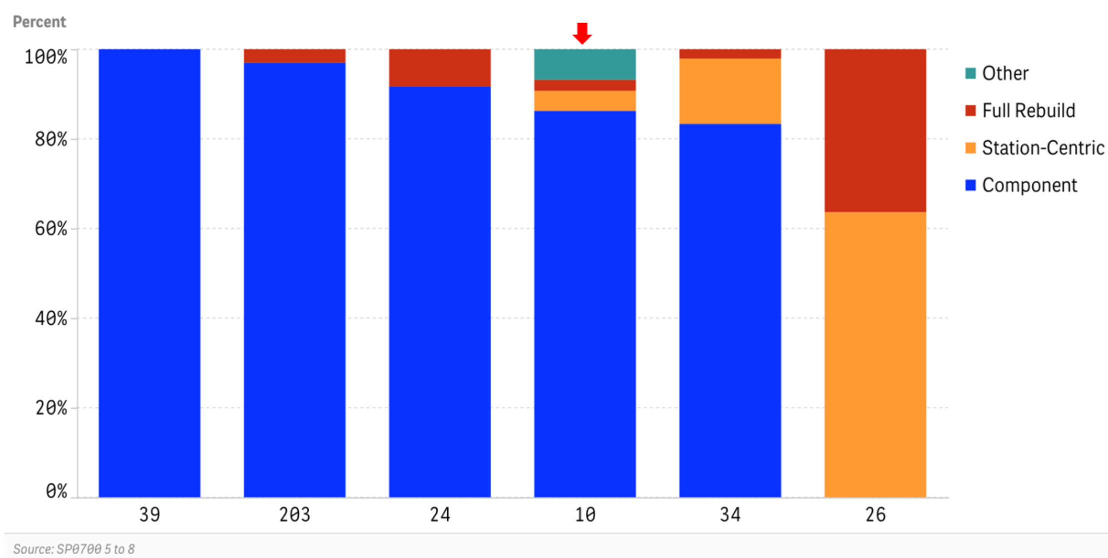


Figure 25 -- Distribution Substation Refurbishments Completed per Distribution Substation: 2020 through 2024 !



CNUC

2020

Hydro One Vegetation Management Study

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2 April 2021

Table of Contents

Executive Summary **1**
1 Introduction **4**
1.1 Study Purpose 4
1.2 Study Team 4
1.3 Goals + Objectives 4
2.0 Methodology **4**
2.1 Benchmarking Framework 4
2.2 HONI's UVM Setting 5
2.3 2017 Change In UVM Strategy 6
2.4 Selecting + Engaging Peer Utilities 7
2.5 Defining and Gathering Data 7
2.6 Data Analysis 8
3.0 Findings and Discussion **8**
3.1 System Attributes 8
3.2 Program Attributes 10
3.3 Operational Outcomes 12
3.3.1 Cycle Length 12
3.3.2 Expenditures 13
3.3.3 Reliability 16
4.0 Key Findings **17**
4.1 System Attributes 17
4.2 Program Attributes 18
4.3 Operational Outcomes 18
4.4 Optimal Cycle Protocol Results 18
5.0 References **19**

Executive Summary

CN Utility Consulting, Inc. (CNUC) was retained to carry out an independent review and assessment of Hydro One Networks Inc. (HONI)'s distribution utility vegetation management (UVM) program. CNUC had previously performed the 2009 and the 2016 HONI UVM benchmarking studies. In addition to benchmarking experience with HONI specifically, CNUC has unique expertise in both UVM and benchmarking in North America.

For this study, CNUC performed comparisons of relevant metrics with an aim to provide insights into HONI's distribution UVM program compared to the utility's organizational peers and past operations. CNUC leveraged data from its survey – *Utilities & Vegetation Management in North America: A 2019 Utility Forestry Census of Tree Activities & Operations* survey (CN-UWSP Survey) in partnership with the University of Wisconsin-Stevens Point (UWSP), which had just been completed at the time CNUC was retained for this study. The CN-UWSP Survey had 71 responding utilities including HONI. That survey represents a major data input for this study, along with other data inputs, as outlined in Table 1 below.

Table 1. Data sets used in report.

Abbr.	Survey	Years averaged	Total participants
Peer 2016	**CNUC 2016 benchmark survey - peer group response**	**2011-2015**	**27**
HO 2016	**CNUC 2016 benchmark survey - HONI response**	**2011-2015**	**1**
AR 2019	**CNUC-UWSP 2019 Industry Survey - all respondent group response**	**2016-2018**	**71**
Peer 2019	**CNUC-UWSP 2019 Industry Survey - peer group response**	**2016-2018**	**17**
Peer 2020	**CNUC 2020 peer group supplemental survey response**	**2019**	**7**
HO 2020	**HONI OCP actuals**	**2018-2020**	**1**

This benchmarking study set out with three objectives:

1. Review HONI's distribution system attributes in relation to peers, other industry survey respondents and HONI's past operations.
2. Compare and contrast HONI's UVM program with peers, other industry survey respondents and HONI's past operations.
3. Analyze the results to date of HONI's Optimal Cycle Protocol (OCP) implementation.

Conclusions for each objective are summarized in the following subsections.

SYSTEM ATTRIBUTES

HONI's service territory is largely rural and remote, heavily forested and often subject to severe weather events and climatic extremes. This distinctive UVM setting creates distribution system attributes that vary in important ways from the HONI peer groups, as well as CNUC's larger industry survey respondent group.

- HONI's number of customers is statistically less than the Peer 2019 average and is statistically greater than the AR 2019 average. But, HONI has a significantly larger system in terms of distribution right-of-way (ROW) kilometres (km) compared to both the Peer 2019 and AR 2019 groups. The result is that HONI has a customer density that is much lower than other utilities.
- HONI's distribution system is much more rural and remote in comparison to other utilities. This is notable because rural and remote areas are more difficult and expensive to access and manage.

PROGRAM ATTRIBUTES

In benchmarking, the context provided by the system attributes describes some of the achieved outcomes of the UVM program but does not have full explanatory power. Additionally, the system attributes cannot be controlled by the UVM program manager. Therefore, to gain a full understanding we must also examine the specific operational activities of Hydro One's UVM program. Notably:

- HONI's scope of UVM work, though statistically different from the Peer 2019 and AR 2019 group generally, is not significantly different from the Peer 2019 group for under clearances. HONI's clearances and interval of work result in percentages of reactive work and trees in contact at the time of work that have no statistical difference from that of the Peer 2019 group but does differ from the AR 2019 group.
- HONI's rate of removal is three-times greater than other survey respondents. HONI has shifted its scope of work to put focus on off-ROW hazard trees. The *2017 Forestry Assessment* estimated that 90% of HONI's distribution outages are caused by this tree population. Therefore, this high rate of removal is likely to pay dividends in the future in improved reliability from hazard tree reduction. Additionally, any tree removal reduces the total tree inventory on the system. A percentage of in-growth is expected each year as new trees seed in or resprout, so to avoid increasing future workloads, reducing this inventory is key.
- HONI's use of herbicides was behind that of Peer 2016 respondents and has decreased since that time, while the Peer 2020 group has increased adoption by over 20%. The use of herbicides is an industry best management practice and is a key tool in reducing the in-growth and regrowth of removed trees.

2017 CHANGE IN UVM STRATEGY

Based on recommendations from the *2017 Forestry Assessment* conducted by Clear Path Utility Solutions, LLC (Clear Path) and Arbormetrics, HONI has shifted from a corridor-based UVM approach to a defect-driven program focused on high-risk trees and tree-powerline conflicts. These recommendations were implemented by HONI through the OCP starting in Q4 2017, with OCP work commencing in earnest in 2018. It was suggested by the *2017 Forestry Assessment* that this approach would result in a reduction in vegetation defects correlating with improved reliability and lower long-term cost. This initial cycle would then be refined and optimized by feeder, based on ongoing data collection. This program continues today.

OPERATIONAL OUTCOMES

The operational outcomes of HONI's UVM program attributes can be examined as measures of the success of the UVM program.

- Through implementation of the OCP, HONI has reduced its maintenance interval from 9.5 years in 2016 to a projected first cycle of 4.1 years. This interval will continue to be optimized through HONI's defect-driven approach and associated data collection in subsequent cycles.
- HONI reduced its maintenance interval by more than half and has done so without increasing the average program budget.
- HONI has seen a reduction in cost per managed ROW km over 50% when comparing 2016 to the OCP average (2018-2020).
- HONI's non-force majeure (FM) system average interruption duration index (SAIDI) remains higher than the Peer 2020 group. This higher non-FM SAIDI is expected due to HONI's service territory. However, since OCP implementation there has been a clear reversal in the HONI Non-FM SAIDI trend for the better.

OPTIMAL CYCLE PROTOCOL RESULTS

Despite a naturally challenging UVM setting, HONI has seen notable improvements to its UVM program through OCP implementation. Since OCP was initiated starting in Q4 2017 to 2020 year-end, HONI has seen:

- **A reduction of maintenance interval from 9.5 to 4.1 years.**
- **An over 50% reduction in cost per managed ROW kilometre when comparing 2016 to the average of the OCP period (2018-2020).**
- **A positive reversal of total distribution system Non-FM SAIDI in minutes, resulting in a total decrease of 13% since 2017, prior to full OCP implementation.**

CNUC expects that HONI's maintenance interval, expenditures and reliability will improve further as the OCP continues to be refined and optimized in the coming cycles through HONI's defect-focused, data-driven approach.

1 Introduction

1.1 STUDY PURPOSE

CNUC was retained to carry out an independent review and assessment of HONI's distribution UVM program. This review was conducted by studying and performing comparisons of relevant metrics with an aim to provide insights into how HONI's distribution UVM program compares with its organizational peers.

CNUC has conducted industry-wide surveys of North American UVM practices and metrics since 2002. In 2009 and 2016, CNUC completed benchmarking projects to determine the relative efficacy of HONI's UVM program. As a basis for those projects, CNUC invited a relevant group of UVM benchmarking members to participate in surveys. The goal of this study is to update the CNUC 2016 UVM benchmarking study for HONI.

1.2 STUDY TEAM

CNUC was selected as an independent third-party consulting team to execute HONI's UVM benchmarking study. CNUC completed both the 2009 and the 2016 HONI UVM benchmarking studies. In addition to benchmarking experience with HONI specifically, CNUC has an expertise in both UVM and benchmarking that is unique in North America, as evidenced by experiences and achievements that CNUC brings as a consulting team.

1.3 GOALS + OBJECTIVES

- Review HONI's distribution system attributes in relation to peers, other industry survey respondents and HONI's past operations.
- Compare and contrast HONI's UVM program with peers, other industry survey respondents and HONI's past operations.
- Analyze the results of HONI's OCP implementation to date.

2.0 Methodology

2.1 BENCHMARKING FRAMEWORK

In consideration of the study purpose and objectives, CNUC used the UVM benchmarking study framework below to guide this study. This report summarizes how CNUC progressed through each stage, along with CNUC's findings.

UVM Benchmarking Study

1	2	3	4	5
Background – Hydro One's UVM Setting	Selecting + Engaging Participants	Defining + Gathering Data	Data Analysis	Conclusions

2.2 HONI'S UVM SETTING

A clear understanding of HONI's UVM practices and operating conditions is critical to the success of the benchmarking study. This section of the report summarizes the necessary background information in these areas.

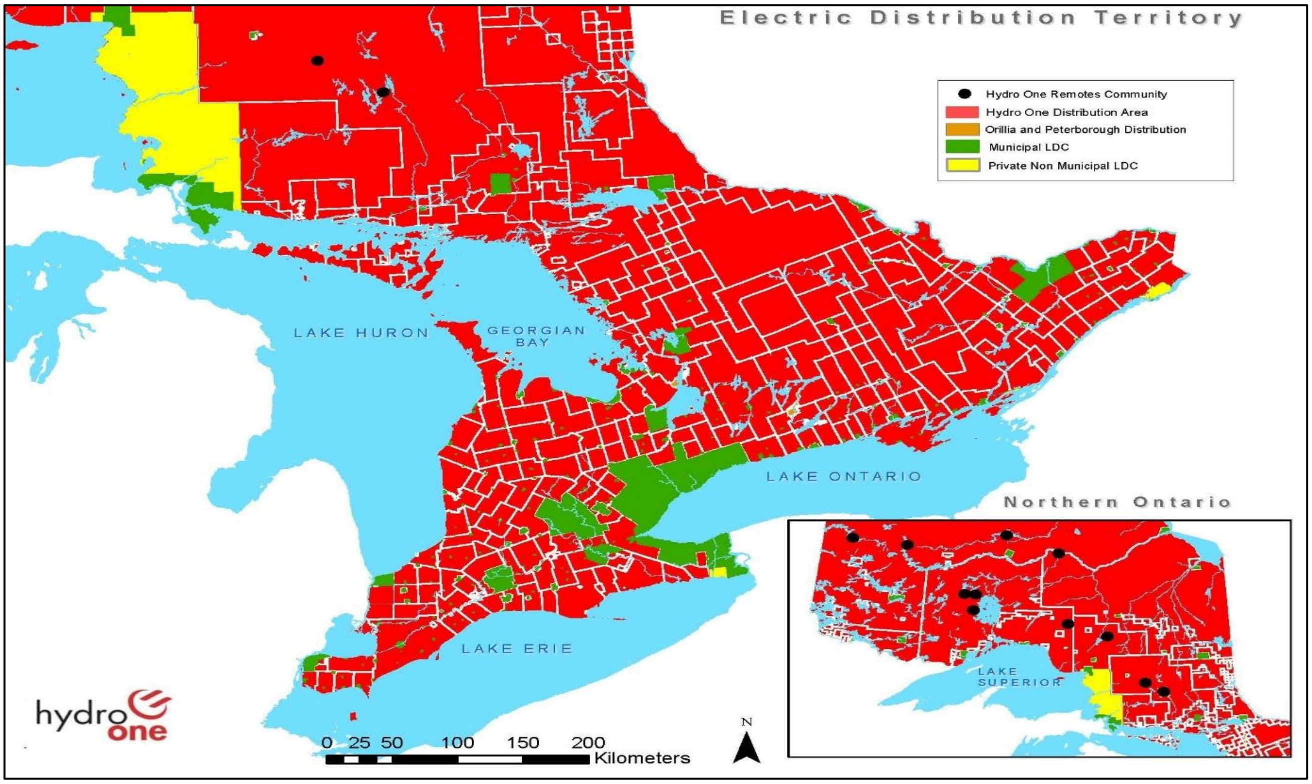

Figure 1. Hydro One service territory

HONI Distribution is one of 60 LDCs that serve the people of Ontario. Aside from a few urban centers such as the Greater Toronto Area, London and Ottawa, and some smaller population centers such as North Bay and Sudbury, the majority of the province of Ontario is served by HONI's distribution system. The province of Ontario is characterized by rural and remote areas. In total, the HONI service territory is approximately 961,000 square kilometres. Ontario is heavily forested, with an estimated 71 million hectares of forest. Its forests can be split into four distinctive regions (see Figure 2): the Hudson Bay Lowlands in the far north, the boreal region in north, the Great Lakes-St. Lawrence region in southern and central Ontario, and the deciduous forest/grassland region in the southernmost part of the province.

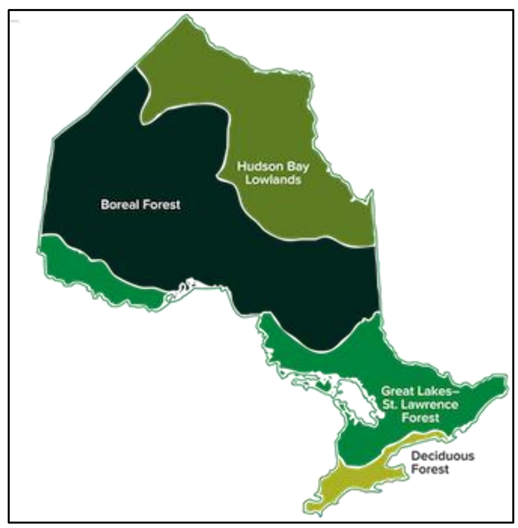

Figure 2. Forest regions in Ontario (Ontario Ministry of Natural Resources and Forestry, 2016)

Each of the four forest regions is made up of distinctive landcover as can be seen in Figure 3. The Hudson Bay Lowlands are dominated by wetlands, bogs and fens, and sparse, slow-growing forest and tundra. The boreal forest is dominated by coniferous and mixed-wood forests. The Great Lakes-St. Lawrence forest is characterized by hardwood and mixed forests. Finally, the deciduous forest region is dominated by agricultural and urban areas with scattered, highly diverse forests and woodlots.

The province of Ontario is dominated by two climate types: humid continental and subarctic (Figure 4). The humid continental climate encompasses the southern and eastern parts of the province and is characterized by warm to hot summers and cold, long winters with ample snowfall. The northern part of the province has a subarctic climate characterized by severely cold winters and short, cool to warm summers with dramatic temperature shifts possible in all seasons. It is not uncommon for the subarctic regions of Ontario to see temperatures of -40°C and for snow to remain on the ground for over half the year.

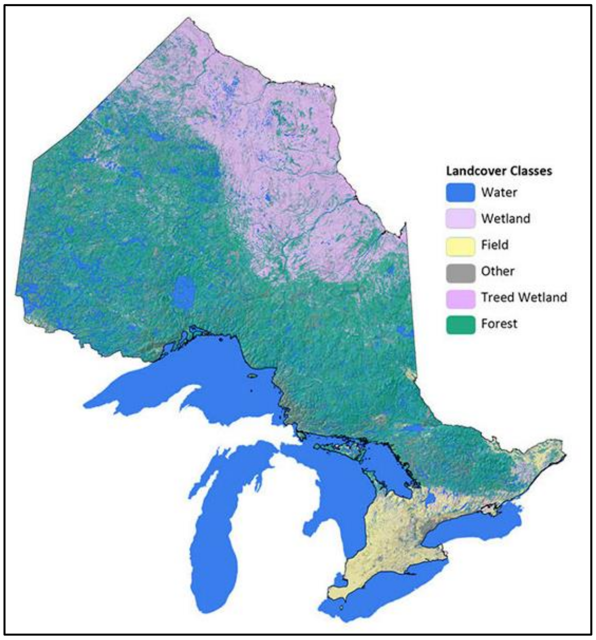

Figure 3. Landcover of Ontario (Ontario Ministry of Natural Resources and Forestry, 2016)

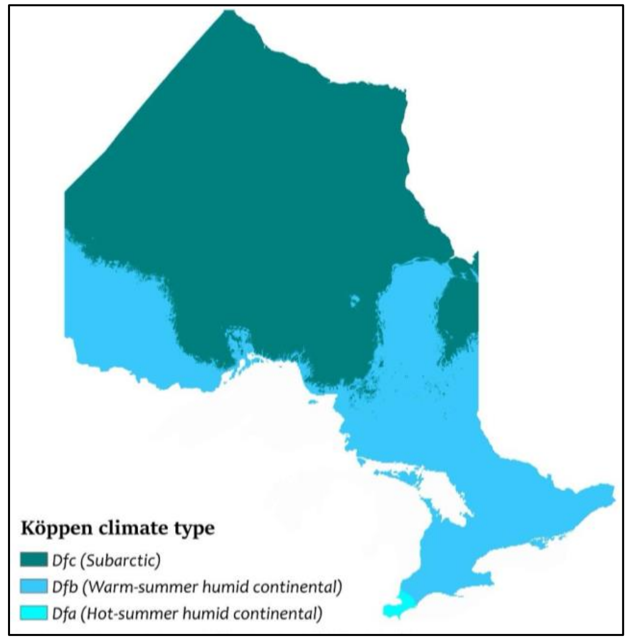

Figure 4. Köppen climate types of Ontario (Peterson, 2016)

The weather of southern Ontario is characterized by lake-effect snow squalls in winter and severe and non-severe thunderstorms that peak in frequency from June through August. The southwestern and central regions have the highest severe weather frequency, however, the far southern part of the province near Windsor has the most lightning strikes per year in Canada, with an average of nearly 36 days of thunderstorm activity annually (CBC, 2013). Ontario averages 12 confirmed tornado touchdowns a year (Ontario Office of the Fire Marshal and Emergency Management, 2015). Finally, tropical depression remnants in the south can cause copious rains and high winds.

2.3 2017 CHANGE IN UVM STRATEGY

One final item of note regarding the HONI UVM setting is the recent implementation of recommendations that arose from the *2017 Forestry Assessment* conducted by Clear Path and Arbormetrics. The recommendations included a shift from a corridor-based approach to one driven by high-risk trees and tree-powerline conflicts (defect-driven program). The new approach began with an estimated three-year maintenance cycle, robust hazard tree and quality control programs to reduce vegetation defects, improve reliability and lower long-term cost. This initial cycle would then be refined and optimized by feeder, based on ongoing data collection. These recommendations were implemented by HONI starting in Q4 2017 with OCP execution commencing in earnest in 2018.

2.4 SELECTING + ENGAGING PEER UTILITIES

CNUC conducted both the 2009 and 2016 HONI UVM benchmarking studies. In 2009, CNUC identified a 14-utility peer group for HONI, as detailed in CNUC's June 2009 HONI benchmarking report. In short, three families of criteria guided peer selection: vegetation cover and density, weather consideration and customer density. A survey was distributed to a larger set of utilities for the 2016 CNUC HONI benchmarking study, expanding the peer group. Following comparative analysis of system characteristics and vegetation cover, selection of peer utilities was based on the 2009 criteria (with preference given to utilities deemed peers in the 2009 study). The result was an increase from 14 to 27 utilities for the Peer 2016 group.

For the current study, CNUC leveraged data from its CN-UWSP Survey, which had just been completed at the time CNUC was retained for this project. The CN-UWSP Survey had 71 responding utilities (AR 2019) including HONI. Among the respondents, 17 utilities that were classified as peers to HONI in either the 2009 or 2016 study were ultimately identified as the peer group (Peer 2019) for this benchmarking study (Table 2).

Table 2. Utilities in the "Peer 2019" Group

Peer 2019 group participants		
Appalachian Power	ATCO*	BC Hydro
Consumers Energy*	Fortis Alberta*	**Hydro One**
Hydro Ottawa	Hydro Quebec	Indian Michigan Power
Manitoba Hydro	National Grid	New Brunswick Power
PacifiCorp *	Public Service of Oklahoma*	Puget Sound Energy*
SaskPower	Unitil*	Xcel Energy (Northern States Power)

*Utilities that responded to the CNUC supplemental survey questions (as discussed below), which constitute the Peer 2020 group.

2.5 DEFINING AND GATHERING DATA

In its past HONI benchmarking projects, CNUC developed surveys for the express purpose of benchmarking HONI against its peer group. In this project, CNUC had just completed one of its routine industry surveys, which largely covered the same scope as previous HONI benchmarking surveys. The survey contained questions related to the following general UVM program areas:

- Utility Characteristics
- Program Management (costs, cost drivers and operations)
- Integrated Vegetation Management (IVM)
- Safety
- Pruning
- Electrical Systems and Reliability
- Communications
- Storm Response

Given that the suite of questions in this routine survey was not an exact match to those used in 2009 and 2016, a supplemental survey was sent to the 17 utilities in the Peer 2019 group to allow for comparison of repeated observations of the same variables over time (referred to as "longitudinal analysis" hereafter). Seven of the 17 Peer 2019 utilities responded to this supplemental questionnaire after at least three follow-ups from CNUC, these seven utilities make up the Peer 2020 group.

For much of the analysis, data from the AR 2019 group (consisting of all respondents to the CN-UWSP Survey) is included. Additionally, data from the Peer 2016 group is included for both longitudinal analysis (for items like cost and reliability) and for comparison to the Peer 2019 group.

2.6 DATA ANALYSIS

The data collected by CNUC was compiled and analyzed. The findings of this analysis are covered in the subsequent sections of this report. This section focuses on the methodology of the analysis and related considerations. Outside of the scope of this study specifically, the responses to the CN-UWSP Survey were examined for possible anomalies and errors, measurements were validated, and follow-up questions were asked to address any disparate responses.

To prepare the data for this study, measurements were converted into metric units and costs were adjusted to 2020 Canadian dollars (CAD) using the annual average change in the Canadian consumer price index excluding gasoline (Statistics Canada, 2020) and the March 26, 2021 USD to CAD exchange rate of $1.26015. Currency conversions were done to facilitate fair comparisons between utilities operating in different countries. While volatility and fluctuations in currency value may place utilities denominating costs in one currency or another at an advantage or disadvantage, CNUC found that such volatility would not materially impact the study's findings.

Within this report we define mean as the arithmetic mean, the sum of values divided by the total responses. The standard error of the mean (SE) was used to denote an estimate of how far the sample mean is likely to be from the population mean. For example, if the current length of the UVM cycle has a mean of 4.5 years (0.18 SE), the expected population mean is between 4.32 and 4.68. Within the report all error bars in a figure are SE bars and are denoted in gold. When comparing two groups, we look to identify a significant difference between the means. A significant difference tells us that the differences seen are most likely not due to chance or sampling error. To identify significant difference, we examine the SE. When SE bars overlap, the difference is not statistically significant. In this report we will use the term "statistically different" to mean that the SE of the comparison group does not overlap the mean with SE of the HONI data.

3.0 Findings and Discussion

The following sections of the report detail CNUC's key findings in three key subsections:

1. System Attributes
2. Program Attributes
3. Operational Outcomes

The first subsection provides relevant context for the HONI UVM program. The second explores the program attributes which lead to the operational outcomes detailed in the final subsection.

3.1 SYSTEM ATTRIBUTES

As context for the comparison between the Peer 2019, Peer 2020, and AR 2019 groups, the first part of CNUC's analysis benchmarks HONI on system attributes that provide the operating context for HONI's UVM program. Section 2.2 above discusses the rural and remote nature of HONI's distribution service territory (i.e., the majority of Ontario, apart from a few urban centers and some smaller population centers). HONI's operating context leads to some unique system attributes in comparison to other responding utilities, as shown in Table 3 and further discussed below.

Table 3. System attribute statistics for Hydro One, Peer 2019 group and AR 2019 group

	ROW km	Standard Error	N*
HO 2020	105,000		
Peer 2019	39,915^{+}	9,519	11
AR 2019	26,042^{+}	5,286	70
	Customers	**Standard Error**	**N***
HO 2020	1,370,000		
Peer 2019	1,421,038^{+}	372,026	11
AR 2019	756,600^{+}	160,416	71
	Customers per km	**Standard Error**	**N***
HO 2020	13.0		
Peer 2019	22.0^{+}	5.4	11
AR 2019	55.0^{+}	13.5	69

* The number of respondents may not equate to the total size of the Peer 2019 or AR 2019 group, because not all respondents in the relevant group answered each question.

$^{+}$Statistically different from HO 2020

First, due to the large service territory of HONI, coupled with its rural and remote nature, HONI has a much greater number of ROW km in comparison to both the Peer 2019 and AR 2019 groups. In fact, HONI has over 2-times more ROW km than the mean of Peer 2019 group and just under 4-times that of the AR 2019 group. At the same time, HONI's customer base is close in size with the average of the Peer 2019 group. Hydro One's customer base is roughly 1.7 times more than the AR 2019 group.

Together, this means that HONI has a much lower customer density. HONI's number of customers per km is 1.7-times smaller than the Peer 2019 mean and just over 4-times smaller than the AR 2019 mean. This is a critical consideration, particularly when examining program expenditures.

Another important system attribute for benchmarking ties directly to the rural and remote nature of the province of Ontario, a driver for the low customer density of HONI (Figure 5). 98% of HONI's ROW km are rural or remote compared to 56% for Peer 2020 and 59% for Peer 2016. This means that only 2% of HONI's ROW km are suburban or urban in comparison to over 40% for both Peer 2016 and Peer 2020. This is notable because urban and suburban areas are more easily accessed and managed.

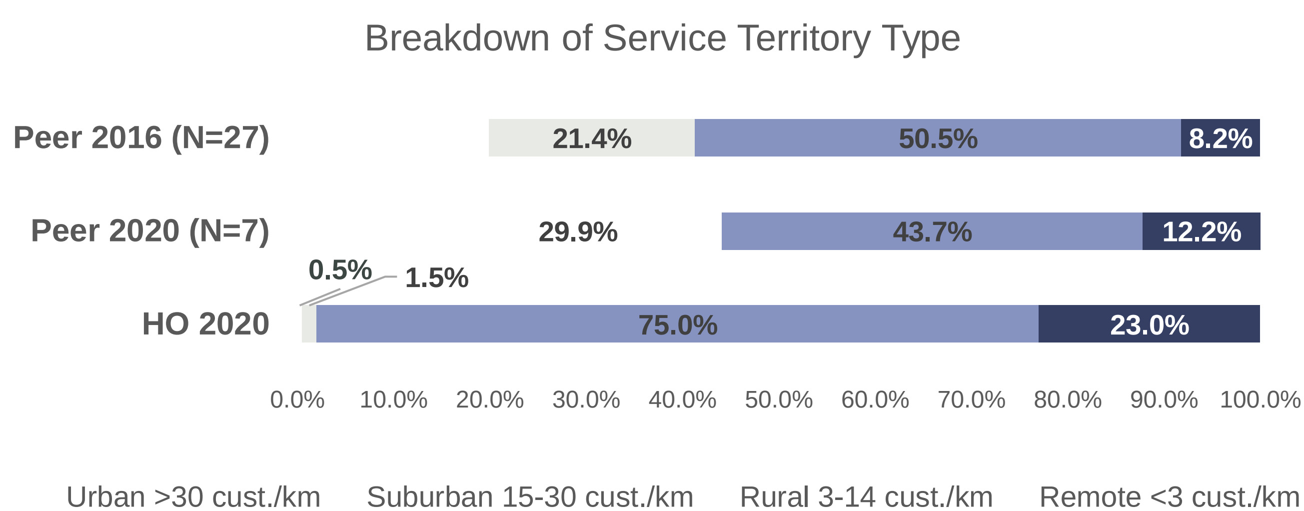

Figure 5. A comparison of the percent of distribution pole kilometres per service territory type

3.2 PROGRAM ATTRIBUTES

System attributes like those discussed in section 3.1 provide insight into the specific setting in which UVM operations occur but do not provide insight into the UVM activities themselves. In examining the specific operational activities of HONI's UVM program, it was important to consider activities called out in the *2017 Forestry Assessment,* which recommended, among other things, alteration of HONI's scope of UVM work.

One way to assess the benefits of scope of work changes is to examine tree clearance from lines following work. Figure 6 below shows a comparison between post-work clearances for three-phase distribution lines for HO 2020 and the Peer 2019 and AR 2019 groups. Though HONI clearances differ statistically from the Peer 2019 and AR 2019 groups generally, HONI post-work under clearances do not differ significantly from the Peer 2019 group. Notably HONI does have statistically less overhang clearance compared to Peer 2019 and AR 2019 respondents, due in large part to several respondents reporting ground to sky clearance (i.e., removing all tree limbs on the wire side of a tree) on three-phase lines. The *2017 Forestry Assessment* recommended a defect-driven strategy (which HONI has shifted to) that focuses on defects (hazard trees and contacts) to reduce costs per km while still producing positive safety and reliability outcomes.

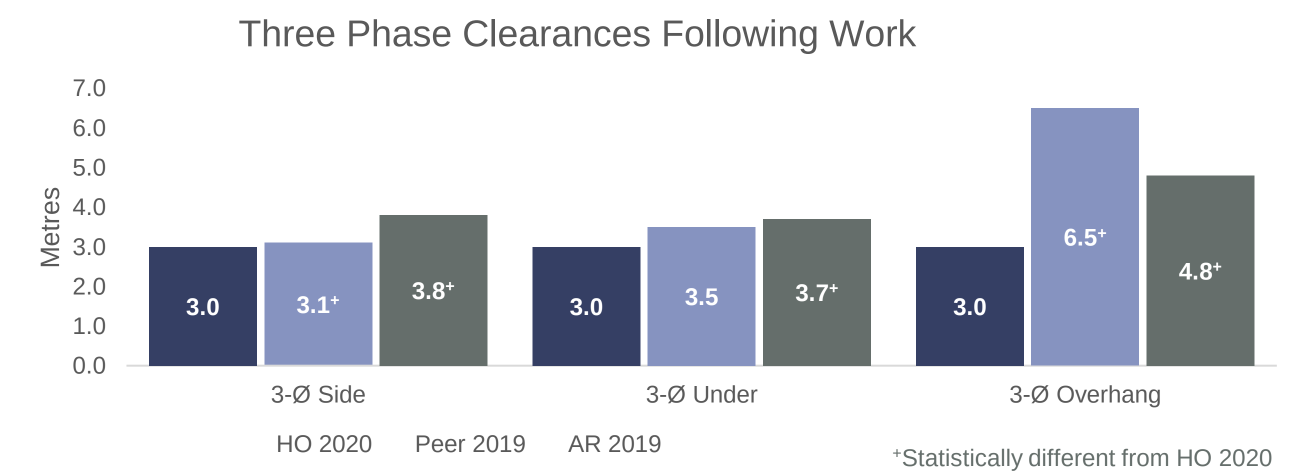

Figure 6. A comparison of metres of clearance on three phase lines following work

Another way to examine scope of work is percent of trees in contact with lines at time of work, which is a good indicator of whether time intervals and clearances are appropriate. As shown in Figure 7 below, HONI's percentage of trees in contact at time of work is not statistically different from Peer 2019. HONI does differ statistically from the AR 2019 mean. However, as HONI continues the OCP strategy, it is expected the percentage of trees in contact will decrease in the future as circuits are revisited with higher frequency.

Figure 7. Comparison of percentage of trees in contact with distribution lines at the time of work

A potential consequence of inadequate clearance or insufficient interval is a high percentage of reactive work (i.e., more trees requiring work outside of planned maintenance cycles as a result), although there will always be a percentage of reactive work that is unavoidable due to storms and other unforeseen circumstances. HONI's percentage of reactive work is in line with both the Peer 2019 and the AR 2019 groups (not statistically different from either) as can be seen in Figure 8.

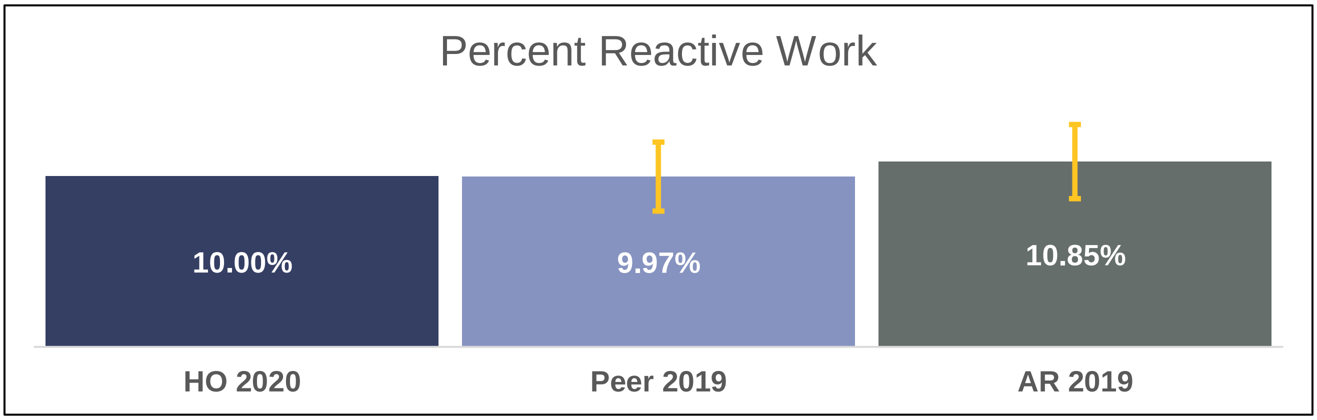

Figure 8. Comparison of percentage of work that is reactive

The *2017 Forestry Assessment* recommended a greater emphasis on reducing high risk trees. HONI has responded by increasing its removals from 20% in 2016 to an average of 60% for the OCP period 2018-2020. This shift in tree removal comes with a shift in work scope of HONI's UVM program. In the *2017 Forestry Assessment*, it was estimated that as much as 67% of the three-year projected defect workload would be related to off-ROW trees. Clear Path and Arbormetrics stated that it is reasonable to expect this annual hazard tree workload will decrease following the first pass through the system with the OCP approach. It was estimated that approximately 50% of the work in the first OCP cycle would be off-ROW hazard trees, which are costly and difficult to identify and mitigate. The report also estimated, based on outage investigation records, that 90% of all distribution system outages appear to be caused by off-ROW tree and branch failures. As the new scope of work targets and removes more off-ROW hazard trees, it is anticipated that reliability metrics will improve since such a high proportion of distribution system outages are caused by this tree population.

To assist in funding the high hazard tree removal rate, Hydro One reduced herbicide use, pausing roadside brush and most spray work. HONI's low use of herbicide is of concern if it persists. IVM is considered a best management practice by system foresters, vegetation managers, academic research, the US Environmental Protection Agency, and many other environmental groups. It has been championed by the ROW Stewardship Council through its *Accreditation Standards for Assessing IVM Excellence* and is the chosen methodology for many arboriculture, forestry and landscape industry professionals. One of the primary tools advocated in IVM is the use of herbicides to prevent ingrowth and reduce resprouting of removed trees. A six-year study by the Electric Power Research Institute (EPRI) determined herbicide control could reduce stem counts of trees in the ROW by 70% compared to manual and mowing cutting methods alone.

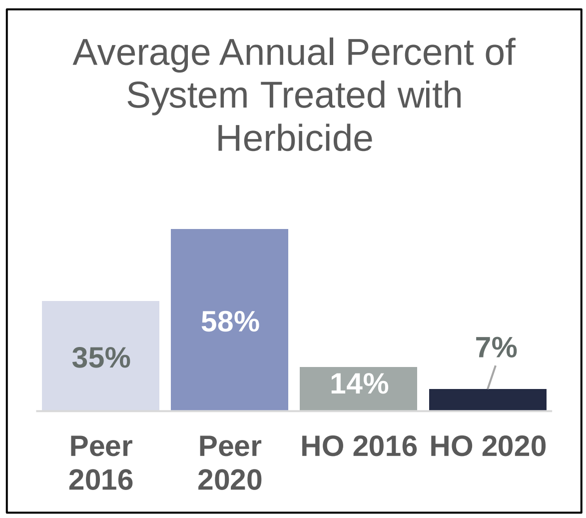

Figure 9. Comparison of adoption of herbicide treatments between HO 2016, HO 2020, Peer 2016 and Peer 2020 groups.

Deciduous plant species resprout after cutting, which increases stem counts and workloads. That workload has been shown to be best reduced through herbicide use (McLoughlin, et. al, 2000). For these reasons, many of the Peer 2020 group utilities have seen an increased adoption of herbicides, as evidenced by an average increase of 23% in their systems treated with herbicides as compared to the Peer 2016 mean. In contrast, HONI's herbicide use has halved over the same period 2016-2020 (Figure 9).

3.3 OPERATIONAL OUTCOMES

The program attributes and activities discussed in section 3.2 have led to positive operational outcomes for HONI. The three operational outcomes of interest are cycle length, program expenditures and reliability metrics, as discussed in sections 3.3.1 to 3.3.3.

3.3.1 Cycle Length

In 2016, HONI had a cycle interval of 9.5 years. The *2017 Forestry Assessment* recommended moving to an initial 3.0-year cycle (followed by a cycle length optimized based on data collected), as well as a shift from a corridor-based approach to a defect-driven program. In Q4 2017 HONI initiated the transition to OCP and commenced full execution in 2018. This newly implemented protocol is based on a starting reference cycle length of 3.0-years, focusing on defects and trees that have the potential to become defects in the next three years, aiming to eventually optimize the cycle by feeder as more data becomes available.

In the first cycle (ongoing), HONI is seeing a projected cycle length of 4.1-years. This is in line with the realized cycle length of the Peer 2019 (not statistically different) and statistically shorter than the AR 2019 (Figure 10). As of the end of 2020, the OCP program has 26.7% of system kilometres remaining to fully realize the projected first cycle length.

The shift from a 9.5-year cycle to a projected 4.1-year cycle since OCP implementation is a mark of success. As the second cycle commences, the individual feeder cycle length will be assessed and optimized where appropriate, based on conditions of the Hydro One utility forest.

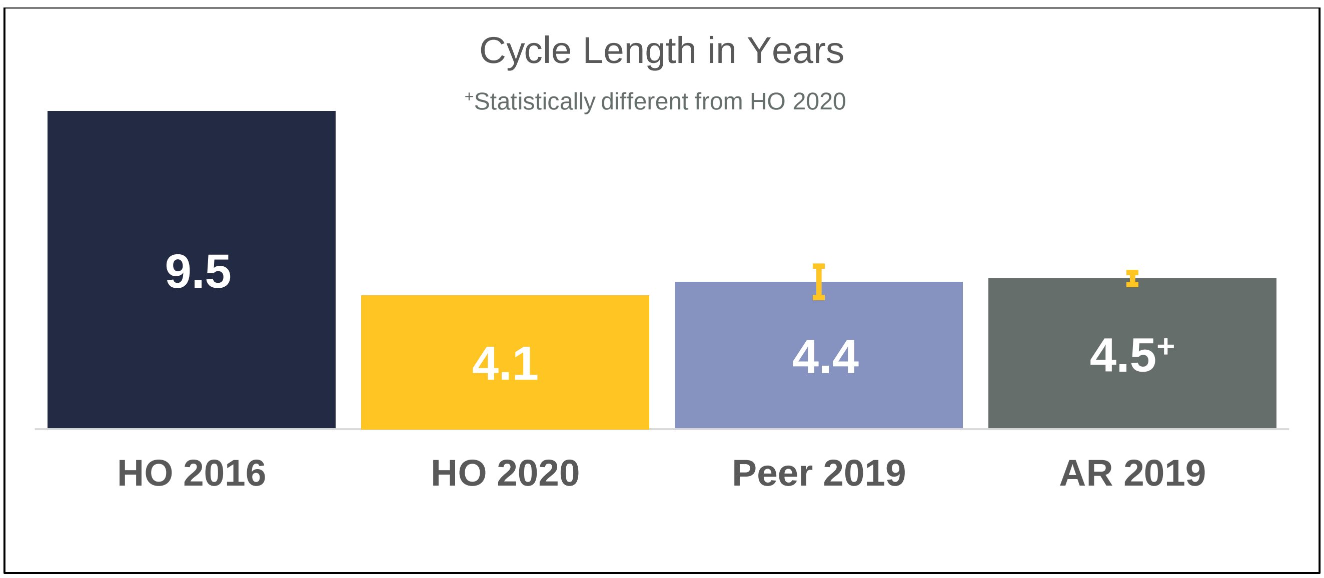

Figure 10. Comparisons of realized cycle length between Hydro One (2016 and 2020), Peer 2019 group and AR 2019 group.

3.3.2 Expenditures

HONI's total UVM expenditures are about four times that of the AR 2019 group average and 2.5 times that of the Peer 2019 group (Figure 11). As discussed in section 3.1, HONI's unique UVM setting contributes to part of this disparity. HONI has nearly the same number of customers as the Peer 2019 group but more than twice the number of ROW km. Additionally, the HONI system is far more rural and remote than that of other respondents. These factors compound to result in a HONI customer density that is much lower than other survey respondents – 41% lower than the Peer 2019 group and 76% lower than the AR 2019 group.

While total program expenditures do not allow for a perfect one-to-one comparison, one of the common ways to normalize data for comparison between companies is to analyze costs on a per unit basis. This section 3.3.2 discusses program expenditures by various common unit measures. As HONI has a distribution system with more than twice the pole kilometres of the Peer 2019 group and nearly four-times larger in pole kilometres than the AR 2019 average, examining UVM distribution expenditures on a per managed ROW km basis helps to normalize HONI's data. The HO 2020 cost per managed kilometre (avg. 2018-2020) is statistically different from that of other respondents excepting, Peer 2016 (Figure 12). Cost per managed distribution ROW km is higher than the Peer 2019 mean and lower than the AR 2019 mean.

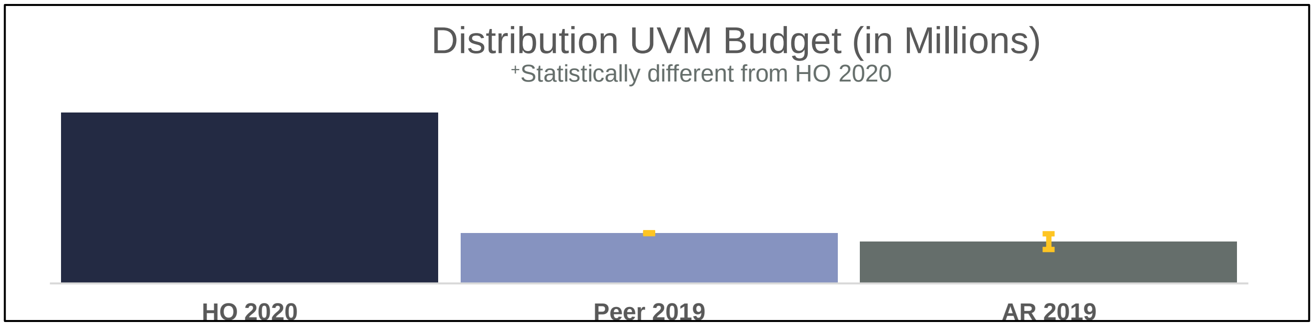

Figure 11 Total distribution UVM budget expenditures (in millions) for HO 2020, Peer 2019 and AR 2019.

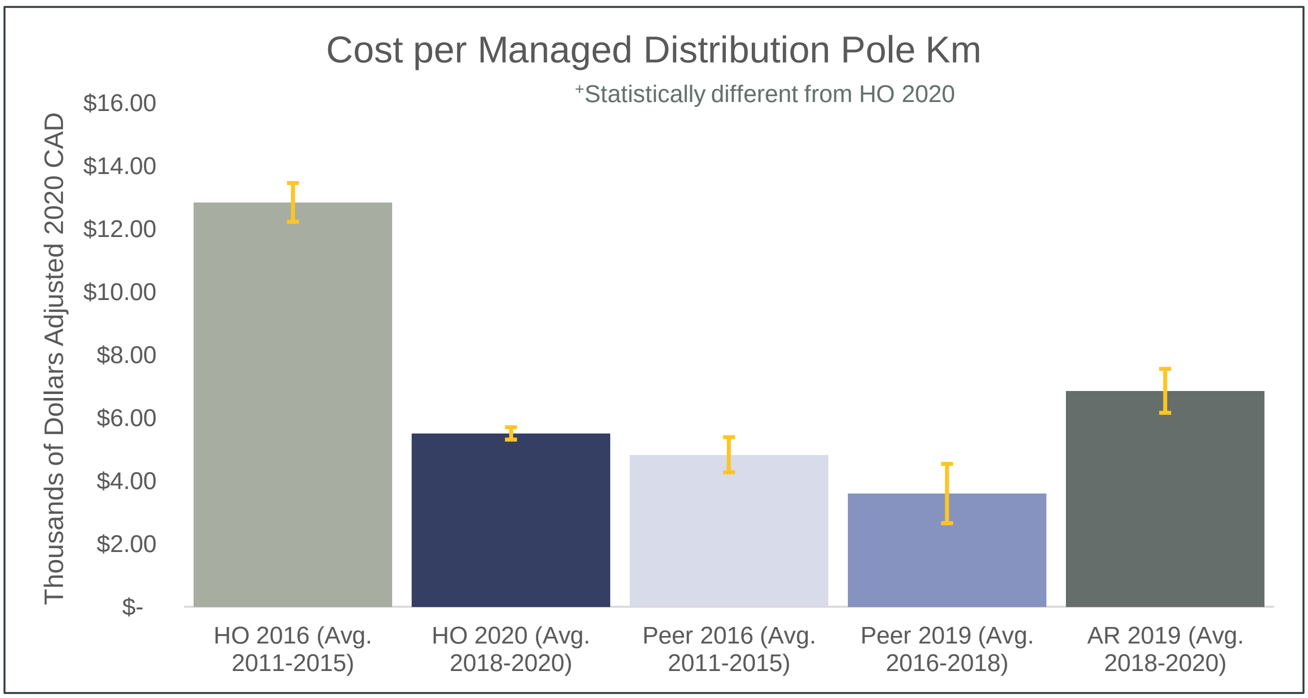

Figure 12. Comparison of UVM distribution costs per managed distribution ROW km in 2020 CAD of Hydro One and all survey groups.

The cost outcomes are significant when evaluating the OCP. The *2017 Forestry Assessment* found that transitioning to an OCP from a corridor-based blanket cycle entails a reasonable probability that the first cycle would stay at or slightly below the existing funding level ($150M) and that subsequent cycles may become less costly as vegetation is controlled. The OCP has dramatically impacted HONI's UVM costs per ROW km. The HONI UVM team completed a higher number of distribution km in a single year than in the past but maintained an average total UVM budget below the 2018 $150M budget. This is evident when examining the change in cost per managed distribution ROW km on a year-by-year basis. In this regard, Figure 13 shows over a 50% decrease when comparing 2016 to the OCP period average (2018-2020) as a result of leveraging the same budget to accomplish more kilometres with the start of the OCP approach.

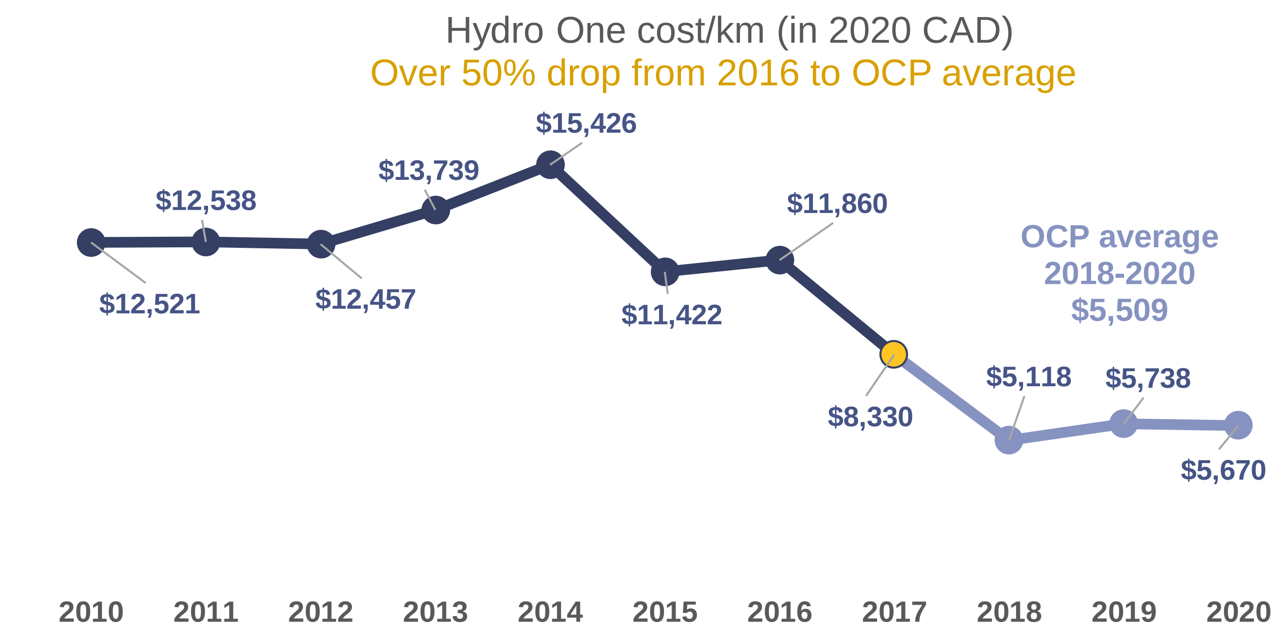

Figure 13. Hydro One cost per managed distribution km from 2010 to 2020 in adjusted 2020 CAD (OCP was initiated in Q4 2017)

Another common approach in comparing cost data for UVM programs is examining cost per customer. HONI has roughly the same number of customers as the Peer 2019 group and a higher customer count than the AR 2019 group average. By cost per customer, HONI's UVM program spend is higher than other survey respondents (see Figure 14). As discussed in section 3.1, HONI has a customer density that is 41% lower than the Peer 2019 group and 76% lower than that of the AR 2019 group, but HONI's customers are spread out over a much larger service territory. This contributes to the large disparity in costs per customer.

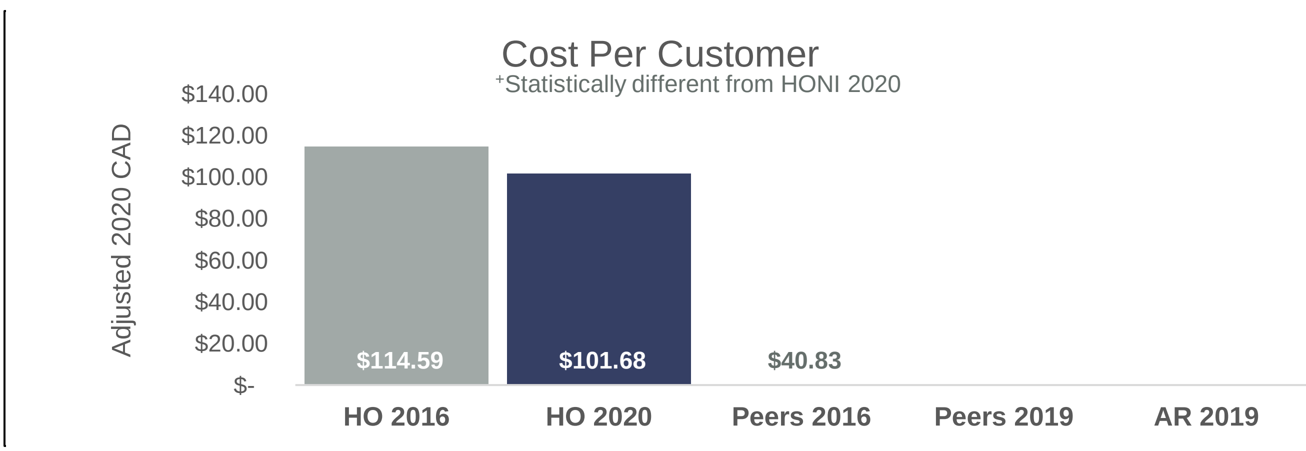

Figure 14. Comparison of costs per customer in 2020 CAD for Hydro One (2016 and 2020), Peer group (2016 and 2020) and All Respondents (2020)

Another common method to examine cost data is cost per managed tree. In this comparison (Figure 15), we can see that HONI's costs are higher than the Peer 2019 group average. One contributing factor to the discrepancy between HONI and the 2019 Peer group may be HONI's high removal to trim ratio in comparison to the 2019 Peer. Labour has been highlighted in previous CNUC benchmarking reports as a primary cost driver of the HONI UVM program which also contributes to the discrepancy. With respect to UVM salaries and UVM hourly wages (Figures 16 and 17), HONI does appear statistically higher for all positions. For salaried positions, HONI is around 1.4 times that of the Peer 2019 group and hourly wages range from 1.2 to 1.8 times higher than the Peer 2019 averages. As previously highlighted in the 2016 HONI benchmark study, these higher wages lead to two notable positive and interrelated outcomes. First, HONI has a much lower turnover rate (5%) compared to its peers (32% for the Peer 2016 group). This low rate of turnover results in HONI personnel having much more experience than the Peer 2016 group. For example, in 2016 HONI had an average qualified utility arborist tenure of 20 years compared to an in-house Peer 2016 group average of 8.75 years (15 year max), and a contracted Peer 2016 group average of 6.5 years (15 year max). The finding of dramatic improvements in cost per distribution ROW km suggests that although hourly wage costs are higher at HONI, they are not a constraining factor in terms of cost efficiency.

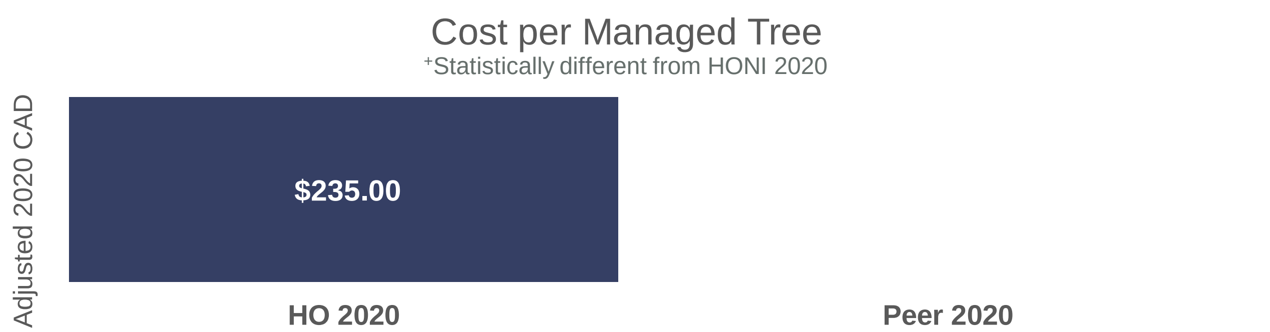

Figure 15. Comparison of costs per managed tree in 2020 CAD for Hydro One and Peer 2019 group

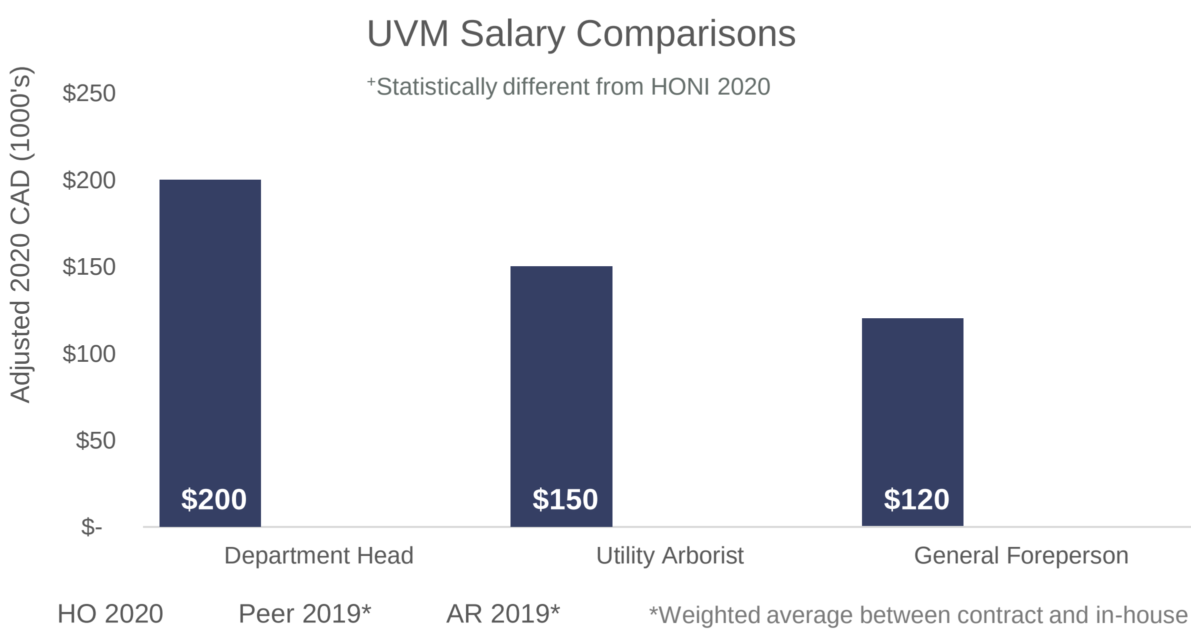

Figure 16. Comparisons of UVM salaries between HO 2020, Peer 2019 and AR 2019 in 2020 CAD.

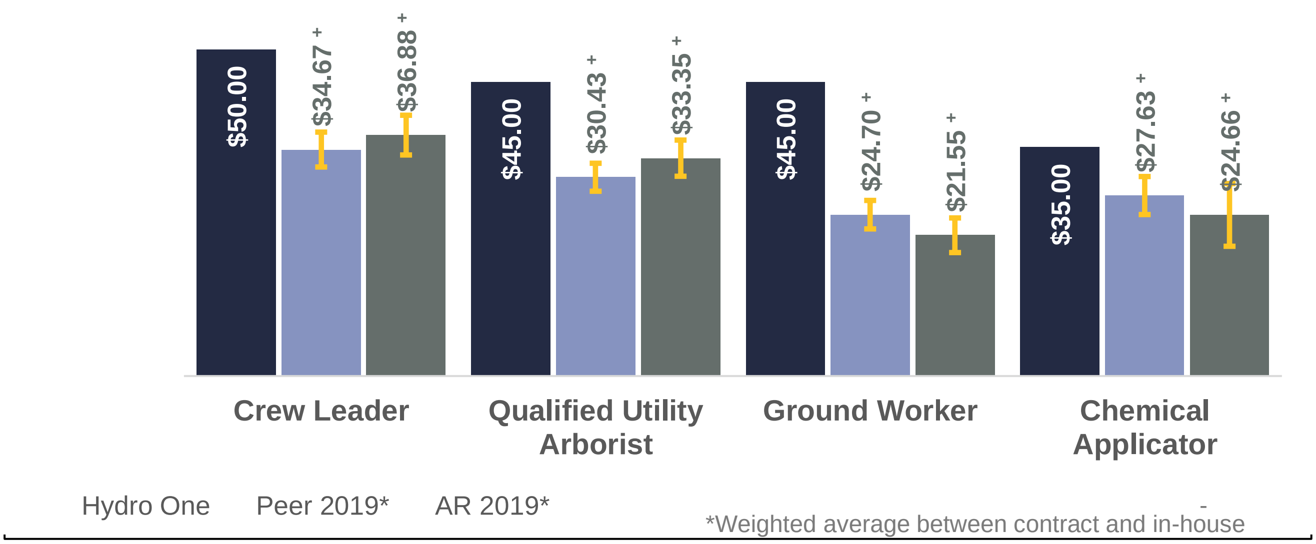

Figure 17. Comparisons of UVM hourly wages between HO 2020, Peer 2019 and AR 2019 in 2020 CAD.

3.3.3 Reliability

System reliability is another key outcome impacted by the change to an OCP from a corridor-driven, blanket cycle. Based on the *2017 Forestry Assessment*'s findings, approximately 90% of all HONI vegetation-caused outages were from off-ROW tree and branch failures, but the HONI UVM scope prior to that study was focused within ROW boundaries. Additionally, it was estimated 6.5% of all outages were caused by tree contacts; these are anticipated to be the easiest to control through OCP due to the increased frequency of work.

CNUC found that HONI's non-FM SAIDI had increased while the non-FM SAIDI of the Peer 2020 group had remained relatively flat (Figure 18). Given that HONI transitioned to the OCP starting in Q4 2017, which is in the middle of the last benchmarked non-FM SAIDI period, CNUC examined HONI's non-FM SAIDI trend more closely as part the current study.

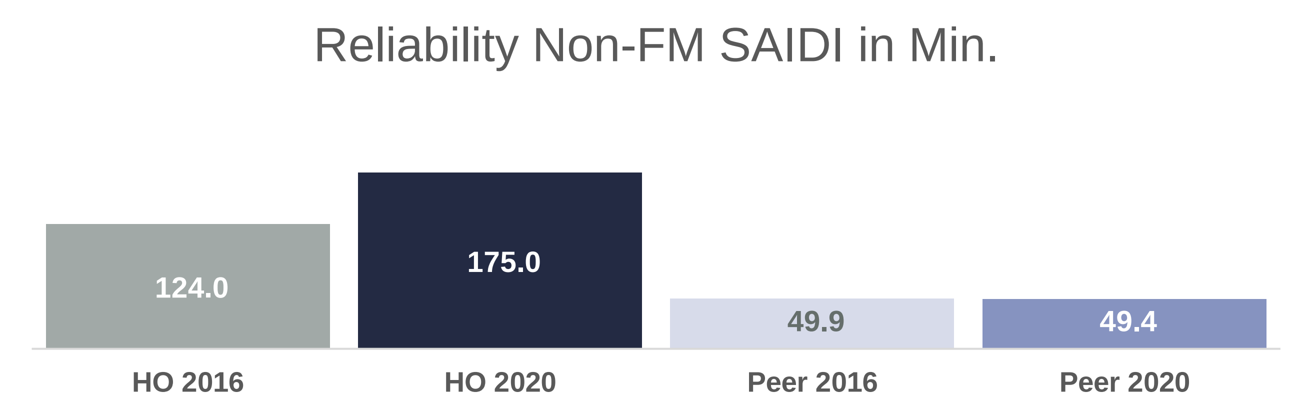

Figure 18. A comparison of Non-FM SAIDI in minutes between HO 2016 and Peer 2016 for the period 2011-2015 to HO 2020 and Peer 2020 for the period 2016-2019.

Figure 19 shows HONI's non-FM SAIDI in minutes from 2010 to 2020. 2017 was the last year of corridor-driven scope of work prior to HONI's commencing the OCP. The years leading up to 2017 saw an overall increasing trend in non-FM SAIDI, which becomes most evident in 2015-2017. There is no reason to believe this trend would have changed without intervention. The implementation of OCP starting in Q4 2017 led to an immediate reversal of the trend in 2018, resulting in a 13% decrease in non-FM SAIDI from 2017 to 2020.

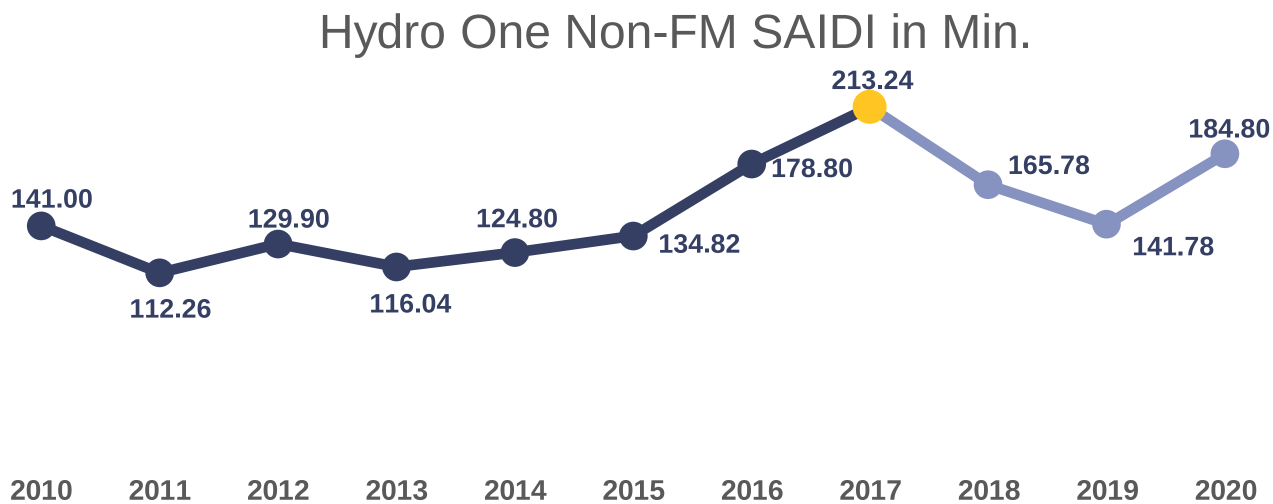

Figure 19. Hydro One Non-FM SAIDI trend in minutes from 2010 to 2020, change to OCP highlighted in yellow

4.0 Key Findings

This update to the CNUC 2016 HONI benchmark study set out with three objectives:

1. Review HONI's distribution system attributes in relation to peers, other industry survey respondents and HONI's past operations.
2. Compare and contrast HONI's UVM program with peers, other industry survey respondents and HONI's past operations.
3. Analyze the results to date of HONI's OCP implementation.

Conclusions for each objective are summarized in the following subsections.

4.1 SYSTEM ATTRIBUTES

In reviewing HONI's distribution system attributes in relation to peers and other industry survey respondents, CNUC found:

- HONI's number of customers is statistically less than the Peer 2019 average and is statistically greater than the AR 2019 average. But, HONI has a significantly larger system in terms of distribution ROW km compared to both the Peer 2019 and AR 2019 groups. The result is that HONI has a customer density that is much lower than other utilities.
- HONI has a distribution system that is much more rural and remote in comparison to other utilities. This is notable because rural and remote areas are more difficult and expensive to access and manage.

4.2 PROGRAM ATTRIBUTES

In examination of the specific operational activities of HONI's UVM program, when benchmarked against the Peer 2019 and AR 2019 groups we find the following:

- HONI's scope of UVM work, though statistically different from the Peer 2019 and AR 2019 group generally, is not significantly different from the Peer 2019 group for under clearances. HONI's clearances and the interval of work result in percentages of reactive work and trees in contact at the time of work that have no statistical difference from that of the Peer 2019 group but differ from the AR 2019 group.
- HONI has a rate of removal that is three-times greater than other survey respondents. HONI has shifted its scope of work to put focus on off-ROW hazard trees. The *2017 Forestry Assessment* estimated that 90% of HONI's distribution outages are cause by this tree population. Therefore, this high rate of removal is likely to pay dividends in the future in improved reliability from hazard tree reduction. Additionally, any tree removal reduces the total tree inventory on the system. A percentage of in-growth is expected each year as new trees seed in or resprout, so to avoid increasing future workloads, reducing this inventory is key.
- HONI's use of herbicides was behind that of Peer 2016 respondents and has decreased since that time, while the Peer 2020 group has increased adoption by over 20%. The use of herbicides is an industry best management practice in reducing the in-growth and regrowth of removed trees.

4.3 OPERATIONAL OUTCOMES

The operational outcomes of HONI's UVM program can be examined as measures of success for the UVM program. Three key outcome areas were examined for HONI's UVM program and compared to industry peers.

- Through implementation of the OCP, HONI has reduced its maintenance interval from 9.5 years in 2016 to a projected first cycle of 4.1 years. This interval will continue to be optimized through its defect-driven approach in subsequent cycles.
- HONI reduced the work interval by more than half and has done so without increasing the average program budget.
- HONI has an average program budget 2.5 times that of the Peer 2019 group, however, this disparity is largely explained by HONI's unique and challenging UVM setting. HONI has a similarly sized customer base as the Peer 2019 group but twice the number of distribution ROW kilometres.
- HONI has seen a reduction in cost per managed ROW km of over 50% from 2016 compared to the average of the OCP period (2018-2020).
- HONI's non-FM SAIDI remains higher than the Peer 2020 group. A higher non-FM SAIDI is expected due to HONI's rural and remote service territory. However, since the OCP implementation began, there has been a clear shift in the HONI Non-FM SAIDI trend for the better.

4.4 OPTIMAL CYCLE PROTOCOL RESULTS

Despite having a naturally challenging UVM setting, HONI has seen notable improvements to its UVM program through the implementation of the OCP. In the period since OCP was fully implemented in 2018 to 2020 HONI has seen:

- **A reduction of maintenance interval from 9.5 to 4.1 years.**

- **A more than 50% reduction in cost per managed ROW km when comparing 2016 to the average of the OCP period (2018-2020).**
- **A positive reversal of total distribution system non-FM SAIDI in minutes, resulting in a total decrease of 13% in non-FM SAIDI minutes by 2020 (compared to 2017).**

CNUC expects that HONI's maintenance interval, expenditures, and reliability will improve further as the OCP is refined/optimized in the coming cycles through HONI's defect-focused, data-driven approach.

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Final Report

Clear Path Utility Solutions, LLC
5600 Cinderella Lane
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Hydro One Optimal Cycle Protocol (OCP) First Cycle Performance Assessment

Date	Services Performed By:	Services Performed For:
April 15, 2021	Clear Path Utility Solutions, LLC 5600 Cinderella Lane Auburn, Ca. 95602	Hydro One Networks Inc.

1. Executive Summary

1.1 Introduction

Clear Path Utility Solutions, LLC (Clear Path) conducted a performance assessment of Hydro One Networks Inc.'s (Hydro One) Optimal Cycle Protocol (OCP) relative to the projections contained in the November 2017 Forestry Assessment that served as the basis for OCP. A third party, Arbor Metrics Solutions ULC, was retained to perform the physical field survey.

OCP work execution commenced in 2018 based on a 2017 forestry assessment and subsequent recommendations to improve performance in the areas of public safety, system reliability and cost.

The 2017 assessment found that the Hydro One vegetation management cycle and work scope were not aligned to provide desired outcomes. Recommendations were focused on aligning the cycle and scope to cost effectively reduce the occurrence of tree caused outages (TCO's) by preventing tree defects[1] determined to be the leading cause of electric service disruptions.

This report assesses the efficacy of OCP implementation to date relative to the 2017 projections to answer the following questions:

1. Does the OCP cycle and work scope prevent tree defects?
2. Does controlling tree defects result in fewer TCOs?
3. Were the first-cycle workload projections accurate?
4. Were unit cost projections to perform the work accurate?

[1] Defects refer to trees and vegetation growing into high voltage conductors and trees with strike potential that exhibit observable conditions such as dead, diseased, decadent, or structurally unsound. See Section 2.1 for further details.

1.2 Project Scope

The scope of this study is highlighted below:

- Perform statistically representative survey of feeders on which clearance was completed pursuant to the OCP in 2018, 2019 and 2020.
    - Survey sampling, data collection and reporting of approx. 200 plots, each plot to be 1-km line aggregated line segments.
    - Use same parameters for data collection as the 2017 survey performed by the same sub-contractor.
    - Random sampling using randomization protocol (for feeders completed in 2019 and 2020).
- Assessment and Findings.
    - Defect analysis of 2018 through 2020 completed OCP feeders relative to the 0-2-year slot class[2] from the 2017 survey.
    - Outage performance assessment of OCP efficacy.
    - Workload and cost analysis comparing 2017 projections with 2018-2020 actuals.

1.3 Key Findings

The assessment found that defects are being controlled, preventing defects reduces the frequency of TCOs, and the projected workload was within the margin of error. However, notification and execution unit costs were above modeled projections.

- A statistically valid and random sampling of completed OCP feeders found a 96% improvement in the number of defects from the 2017 survey relative to 0-2-yr. slot class.
- An analysis of TCOs comparing non-OCP feeders with feeders on which OCP work has been executed demonstrated an improvement of between 23% and 41% (as illustrated in Section 3, Table 7), which suggests the 20% to 40% reduction of TCOs modeled in the 2017 assessment is achievable.
- First cycle workload (i.e., number of trees trimmed or removed pursuant to the OCP) for 2018-2020 was 13% greater than 2017 modeled projections.
- Actual unit cost (trees & km) was significantly higher than 2017 modeled cost, due to factors that were not known or anticipated and could not reasonably have been accounted for in the initial projections, as described in Section 5.3, including higher than projected defect workload.
- Potential opportunity to modify cycle length on certain feeders or areas.

[2] Slot class was one of four stratifications used in the 2017 sampling methodology to classify feeders by time elapsed since clearance work was last completed. For example, the "0-2 slot class" represented feeders last completed within 2-years of the 2017 survey.

2. OCP Defect Control

2.1 Summary

Field surveys were conducted to assess OCP defect loads after each performance year relative to the 2017 assessment. Surveys were performed by Arbor Metrics Solutions, ULC using the same sampling methodology, collection tools and process as the original 2017 assessment. Sampling focused on feeders on which vegetation clearing was completed pursuant to the OCP in the years 2018, 2019 and 2020, consistent with the 0-2 Slot Class from the 2017 survey. Incomplete or partially completed feeders were not sampled.

The 2017 Forestry Assessment by Clear Path suggested that controlling tree defects would have direct and positive impact on system reliability and public safety by preventing controllable service disruptions caused by vegetation. Defects are an undesirable condition, defined as trees and vegetation growing into high voltage conductors and trees with strike potential that exhibit observable conditions such as dead, diseased, decadent, or structurally unsound. As noted in section 3 below, off right-of-way trees accounted for 80% of all outages, including 50% caused by tree or branch failures that were dead or had visible signs or decay, disease, and 7% by trees growing into the conductor from both on and off the ROW.

Surveys were designed to assess completed OCP work to determine if the new work scope is effective in preventing defects from the time of work through the duration of a presumed 3-year cycle - relative to the 2017 assessment, using the 0–2-year slot class as the baseline measurement.

- 2018 OCP completed feeders were surveyed 4th quarter 2018.
- 2018 and 2019 OCP completed feeders were surveyed 1st quarter 2020.
- 2018 – 2020 OCP completed feeders were surveyed 1st quarter 2021.

Data collected included:

- Feeder characteristics – feeder class, name, climatic zone, plot coordinates/length, and OCP year complete.
- Survey findings – vegetation type, observed and projected defects by end of first cycle.

For added clarity, below are definitions on how the term "defect" is used through the remainder of the document.

- Current or Observed Defect –observed condition of trees or vegetation growing into high voltage conductors and trees with strike potential that exhibit observable conditions such as dead, diseased, decadent, or structurally unsound.
- Projected Defect – not yet a current or observed defect but projected to be a defect before a specified date or time horizon.
- Defect workload –number of trees that need to be mitigated to prevent observed defects from materializing through the duration of the planned cycle. Typically, defect workload is the combination of current and projected defects through the cycle duration.

2.2 Defect Survey Results from 2017 Assessment

The 2017 defect survey results, as shown in Figure 1[3] and Table 1, identified 3.30 defects per km within 2 years after feeders had been worked and 5.5 defects per km at the 3 to 5-year point and rapidly increasing thereafter. The survey estimated more than 800,000 defects across the Hydro One system at an average rate of 8 defects per km.

Projected defect rate is a forward-looking projection of emerging defects expected over the subsequent 3-year time horizon of the first cycle. The combination of existing and projected defects was used to estimate workload necessary to abate existing defects and prevent new occurrences of defects over a 3-year projected time frame.

Figure 1 – 2017 Clear Path Survey Defect Results

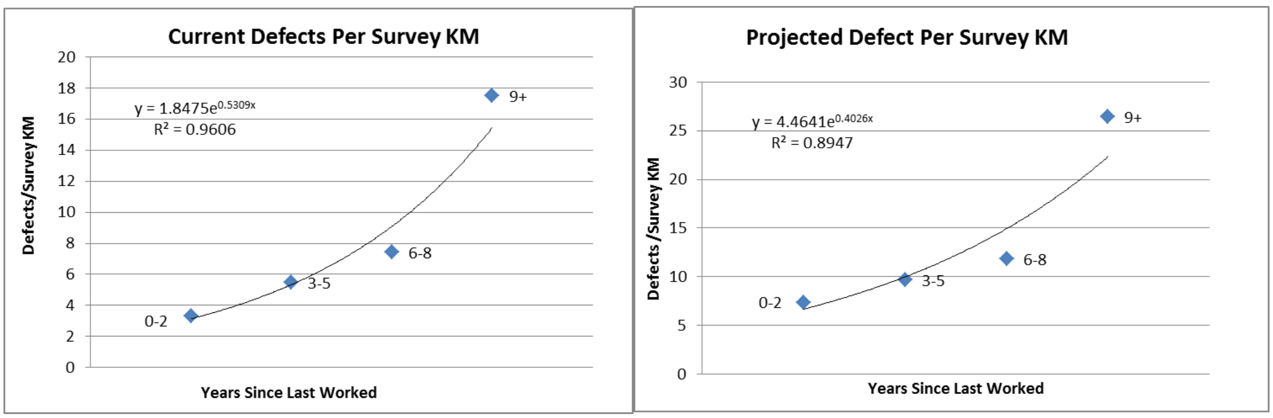


Table 1 – 2017 Survey Defect Rates

Years Since Last Worked	0 - 2	3 - 5	6 - 8	9+
Tree Contact Defects per KM on ROW	0.31	0.76	1.96	5.91
Tree Contact Defects per KM Off ROW	0.23	0.17	0.48	1.43
Brush Contact per KM On & Off ROW	0.07	0.45	0.44	4.59
Hazard Tree Defects per KM Off ROW	2.70	4.10	4.57	5.56
Total Defects Per KM	3.30	5.47	7.45	17.49

2.3 Defect Survey Results from post OCP surveys

The results of surveys performed in 2018, 2020 and 2021 are summarized in Table 2. The results of the 2021 OCP Survey is further explored in Tables 3 through 5.

[3] Figure 1 represents pre-OCP current and projected defects across the Hydro One system as a "snapshot in time" from the 2017 survey by slot class. This is not a projection of post-OCP future workload.

Table 2 – OCP Completion Surveys performed in 2018, 2020 and 2021

Survey Year[4]	km Surveyed	Brush[5] Contact	Tree[6] Contact	Hazard[7] Tree	Total Defects	Per km
2017 Baseline						3.30
2018 survey	74	1	16	5	22	0.29
2020 survey	212	5	6	2	13	0.07
2021 survey	211	6	27	2	35	0.16
Total	497	12	49	9	70	0.14

Note: The OCP feeders included in the 2018 survey were random but not statistically representative (largely due to the relatively low number of kms completed at the time) while 2020 & 2021 surveys included statistically representative samples.

Table 3 – 2021 OCP Survey Defects by Feeder Class

Feeder Class[8]	km Surveyed	Brush Contact	Tree Contact	Hazard Tree	Total Defects	Per km
F Class	176	6	23	2	31	0.18
M-Class	35	0	4	0	4	0.11
Total	211	6	27	2	35	0.16

Table 4 – 2021 OCP Survey Defects by Climatic Zone

Climatic Zone[9]	km Surveyed	Brush Contact	Tree Contact	Hazard Tree	Total Defects	Per km
A	54	0	5	0	5	0.09
B	52	5	18	0	23	0.44
C	52	1	4	2	7	0.13
D	53	0	0	0	0	0.00
Total	211	6	27	2	35	0.16

Note: See Appendix 1 for the definitions of various climactic zones.

Table 5 – 2021 OCP Survey Defects by OCP Year Worked

OCP Year Complete	km Surveyed	Brush Contact	Tree Contact	Hazard Tree	Total Defects	Per km
2018	81	6	12	0	18	0.22
2019	86	0	8	2	10	0.12
2020	44	0	7	0	7	0.16
Total	211	6	27	2	35	0.16

[4] Survey year represents each of the 3 post-OCP surveys performed as described in Section 2.1.
[5] Brush contact is defined as < 10 cm in diameter with evidence of contact with the conductor.
[6] Tree contact is defined as > 10 cm in diameter with evidence of contact with the conductor.
[7] Hazard tree is defined as trees with strike potential that exhibit observable conditions such as dead, diseased, decadent, or structurally unsound.
[8] Feeder Class – M-Class are sub-transmission 44kV and F-Class are distribution feeders.
[9] Climatic Zones are described in Appendix A.

Table 6 is a forward-looking projection of expected defect load at the end of the first 3-year cycle, which is intended to illustrate the projected defect rate 3 years after feeder completion. Current defects are those observed at time of the survey and projected defects are trees expected to become defects on the following timeline.

- 2018 completed OCP feeders looking forward one year to 2021.
- 2019 completed OCP feeders looking forward two years to 2022.
- 2020 completed OCP feeders looking forward three years to 2023.

As illustrated in the 2017 assessment, defect rates begin to increase 3-4 years after work has been performed, although at different rates between climatic zones.

Table 6 – Projected Defects at Start of Second Cycle by Zone

Zone	km Surveyed	Current Defects	Projected Defects	Total	Per km
A	54	5	22	27	0.49
B	52	23	68	91	1.75
C	52	7	51	58	1.11
D	53	0	27	27	0.51
Total	211	35	168	203	0.96

Note: Table 6 is not a second cycle workload projection but rather projects the defects prior to the start of the second cycle presuming 3 years as originally planned, expected to increase at a higher rate if the cycle is extended beyond 3 years.

2.4 Conclusion

OCP survey defect results indicate OCP has been effective at reducing vegetation defects, a significant improvement from the 2017 pre-OCP defect rate at the equivalent 0-2-year slot class.

Survey results indicated the improved defect rate is sustainable by comparing the observed survey defect rate of 0.16 on 3-years of completed feeders to the 0-2-year slot class rate of 3.30, suggesting a 95% improvement on completed feeders.

The 2017 survey estimated 800,000 defects existed across the Hydro One distribution service territory, equating to an average system rate of nearly 8 defects per km over all slot class intervals since last worked. Upon completion of the first full OCP cycle, overall system conditions will have improved from an estimated 800,000 pre-OCP defects to less than 20,000 post-OCP on a 3-year cycle and 90,000 on a 4-year cycle (as further discussed below).

There is evidence from the survey of opportunities to lengthen the cycle from 3 to 4 (or more) years in certain areas where trees may hold (i.e., not become a defect) beyond 3 years. This is particularly true for portions of Zones A & D warranting further investigation but outside the scope of this report.

The survey that was completed in January 2021 presumed a 3-year cycle when projecting the defect rate as shown in Table 6. Due to numerous factors further described in this report, Hydro One is projecting a first cycle length of approximately 4 years. More specifically, the average annual kilometers of rights of way managed through the first 3 years of OCP implies a 4.1-year cycle. This would result in a higher defect rate at the start of the second cycle in 2022. We can reasonably infer the following:

- The defect rate for feeders cleared in the first year of the approximate 4-year cycle will increase above the 0.96 rate noted in Table 6 as a result of adding one additional year to the cycle duration.
- The observed defect rate across the Hydro One distribution service area will be significantly less than the 8 defects per km average prior to OCP.

Based on the following factors, a system defect rate of 0.88 per km could be reasonably expected based on an approximate 4-year cycle. While higher than that of a 3-year cycle, this defect rate represents a significant improvement compared to the pre-OCP defect rate of 8.0 per km.

- 26,250 feeder km (25% of total feeder km) 1-year old at 0.12 defects per km derived from the 2021 survey.
- 26,250 feeder km (25%) 2-year-old at 0.22 defects per km derived from the 2021 survey.
- 26,250 feeder km (25%) 3-year-old at 0.96 defects per km derived from the 2021 survey.
- 26,250 feeder km (25%) 4-year-old forecasted at 2.2 worst case scenario based on the difference between the 2017 survey 0-2 slot class and 3-5 slot class.

3. Tree Caused Outage (TCO) Analysis

The ultimate measure of OCP success is the impact on TCOs. OCP is premised on defects being a major contributor to outages relative to the overall tree population, and by eliminating defects, reliability will improve.

Analyzing the impact of OCP work in reducing outages (proving a negative) is challenging as benefits are not realized until after OCP work is performed and the work and resulting benefits in terms of TCO reductions are not linear throughout the year. Further, weather variability can have a significant impact on outage performance from year-to-year skewing comparative analysis. Normalizing the data, as discussed in Section 3.2, allowed for a more accurate representation of OCP efficacy.

3.1 Reliability Prediction Models from the 2017 Assessment

Predictive models from the 2017 assessment suggested a potential 20% to 40% reliability improvement with implementation of OCP as shown in Figure 2 below. This projected range is premised on the projections that a reduced maintenance cycle would contribute to a reliability improvement of up to 20% and targeted work scope (i.e., removal of off-ROW hazard trees) to another 20%.

Methodology behind the 2017 reliability model
The modeled improvement potential was based on analysis of Hydro One tree related outage data, field discovery and professional experience.

The 2017 assessment analyzed nearly 12,500 outages from 2016 mapped to the year feeders were last worked. Feeders worked within 3 years experienced 20% fewer outages on a per km basis than the population at large, a direct correlation between time since last worked, defect load over time (as discussed in Section 2), and outage frequency. This suggested that a shorter cycle alone, with no change of work scope, could reduce outages by as much as 20%.

Further, the 2017 assessment sampled 262 outage events, performing a root cause analysis with the following results:

- Off right-of-way trees accounted for 80% of all outages, including 50% caused by tree or branch failures that were dead or had visible signs or decay, disease, and 7% by trees growing into the conductor.
- 59% were from five species of tree, Balsam (24%); Poplar (15%); Spruce (8%); Pine (8%); and Elm (4%).

The 2017 assessment clearly illustrated a shorter maintenance cycle and targeted work scope to include off ROW trees had potential to achieve 20% to 40% reliability improvement.

Figure 2 – 2017 Assessment Reliability Modeling from 2017

4.4 Reliability Modeling

Using historical outage data and information on years since last worked, it is possible to create a model which forecasts the number of outages the system will incur moving to a modified cycle. Figures 10 and 11 (below) illustrate the number of outages and percent of outage reduction per year, after implementing a 3-year cycle with no changes to the current patrol standard. It is significant to note that the decrease in outages from only a cycle change flattens over time and additional reductions would require changes to the Dx standard and/or focused reliability efforts.

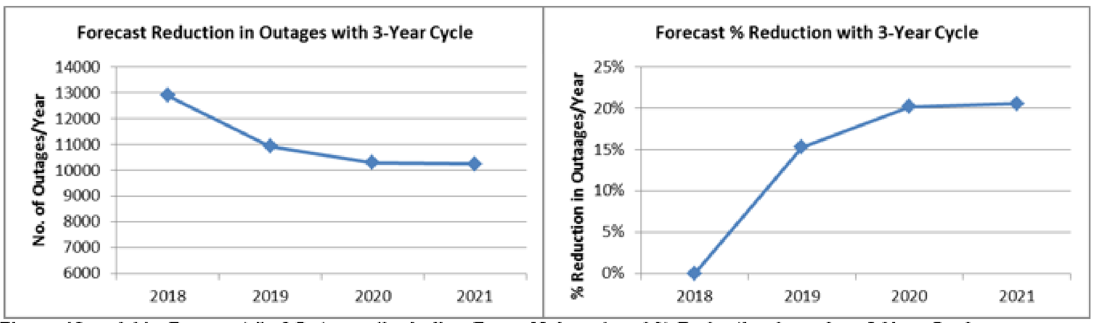


Figure 10 and 11: Forecast # of Outages (including Force Majeure) and % Reduction based on 3-Year Cycle

4.5 - Conclusion

Hydro One can reasonably expect a 20% to 40% (or better) reliability improvement moving to a shortened maintenance cycle, updating the patrol standard to match clearance requirements to cycle interval and implementing a more rigorous approach to hazard tree mitigation. As described above, modifying the cycle alone could produce a 20% improvement and based on field investigation results removal of dead trees could eliminate an additional 20% of the outages.

3.2 Post OCP Outage (TCO) Analysis

TCO frequency was analyzed on an event per km basis, by month, for the years 2018 through 2020 by segregating TCO occurrence on feeders before and after OCP work was performed. This approach helps normalize the data addressing year-to-year weather variability, illustrating a more accurate representation of OCP efficacy.

Feeders were labeled with the month and year OCP was completed and each TCO was categorized to identify if the TCO event occurred before or after OCP work was completed on the relevant feeder. A small number of TCO's occurred in the same month OCP work was completed and were excluded from the analysis as "unable to determine" pre or post OCP.

In each of the years analyzed (2018, 2019 and 2020), feeders where OCP work had been completed demonstrated fewer TCO's than feeders where OCP work had not been completed.

Month to month trend lines between pre and post OCP feeders shown in Figures 3-5 and 9-11 demonstrate a clear pattern of improvement where OCP work had been completed. As shown by the differential between pre-OCP and post-OCP TCOs (Table 7) and further illustrated in the graphs below, improvement was particularly evident during force majeure (FM) storm events.

The accumulated annual differential (improvement) between OCP and non-OCP feeders ranged from 23% to 41% as depicted in Table 7 and Figures 6-8 and 12-14. Figures 6-8 and 12-14 illustrate performance for each respective year relative to the 3-year average from 2015-2017 demonstrating notable improvements between pre- and post-OCP feeders.

- **2018** – Pre-OCP feeders experienced 35% more TCO's per 100 km than the previous 2015-2017 average while post OCP feeders performed 20% better than the same 3-year average. Excluding FM events, 2018 pre-OCP performance mirrored the 3-year average while post-OCP feeders performed 40% better.
- **2019** – Pre-OCP feeder performance mirrored the 2015-2017 average while post-OCP feeders performed 23% better. Excluding FM events, pre-OCP feeders performed 11% worse than the 3-year average while post-OCP feeders performed 16% better.
- **2020** – Pre-OCP feeders performed 43% worse than the 3-year average while post-OCP feeders mirrored the 3-year average. Excluding FM events, pre-OCP feeders performed 39% worse than the 3-year average while post-OCP feeders mirrored the 3-year average. While on the surface it appears OCP feeders performed no better than the 2015-2017 average, they performed far better than non-OCP feeders which is more reflective of benefits during an above average storm season.

Table 7 – Pre and Post OCP TCO's per 100 km

	FM Included				FM Excluded			
Year	Pre OCP	Post OCP	Diff	%	Pre OCP	Post OCP	Diff	%
2018	13.18	7.81	5.37	41%	7.10	4.28	2.82	40%
2019	9.40	7.27	2.13	23%	7.86	5.98	1.88	24%
2020	14.06	9.80	4.26	30%	9.87	7.10	2.77	28%

Figure 3 – 2018 TCO's OCP v. Non-OCP Feeders (including FM events)

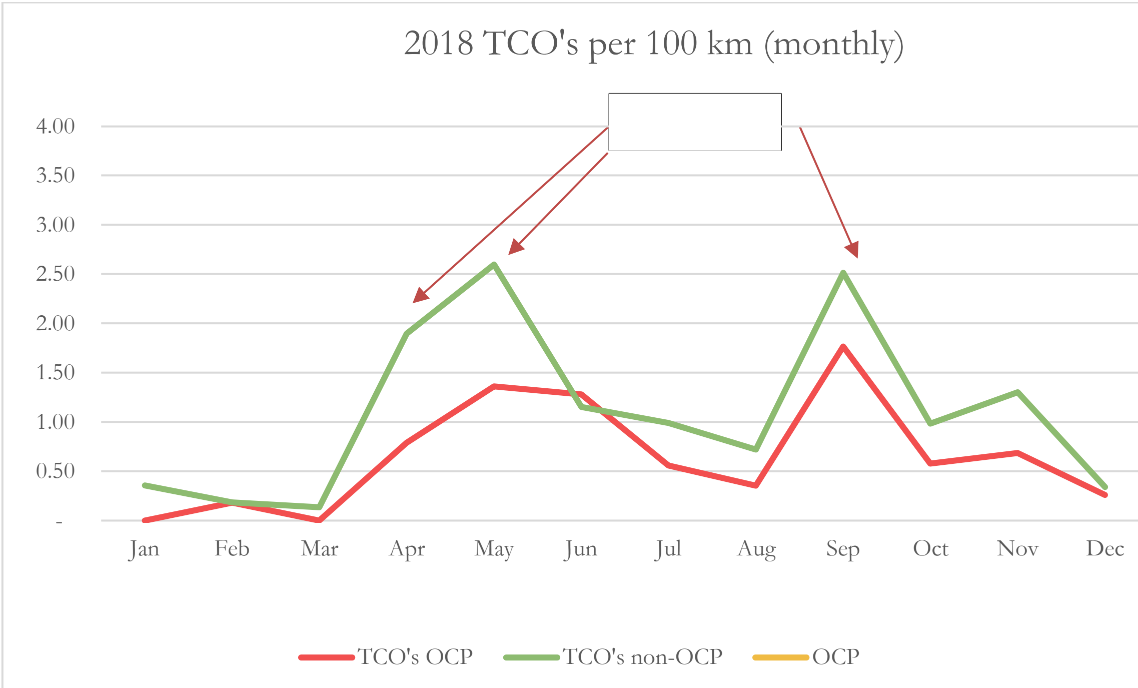


Figure 4 – 2019 TCO's OCP v. Non-OCP (including FM events)

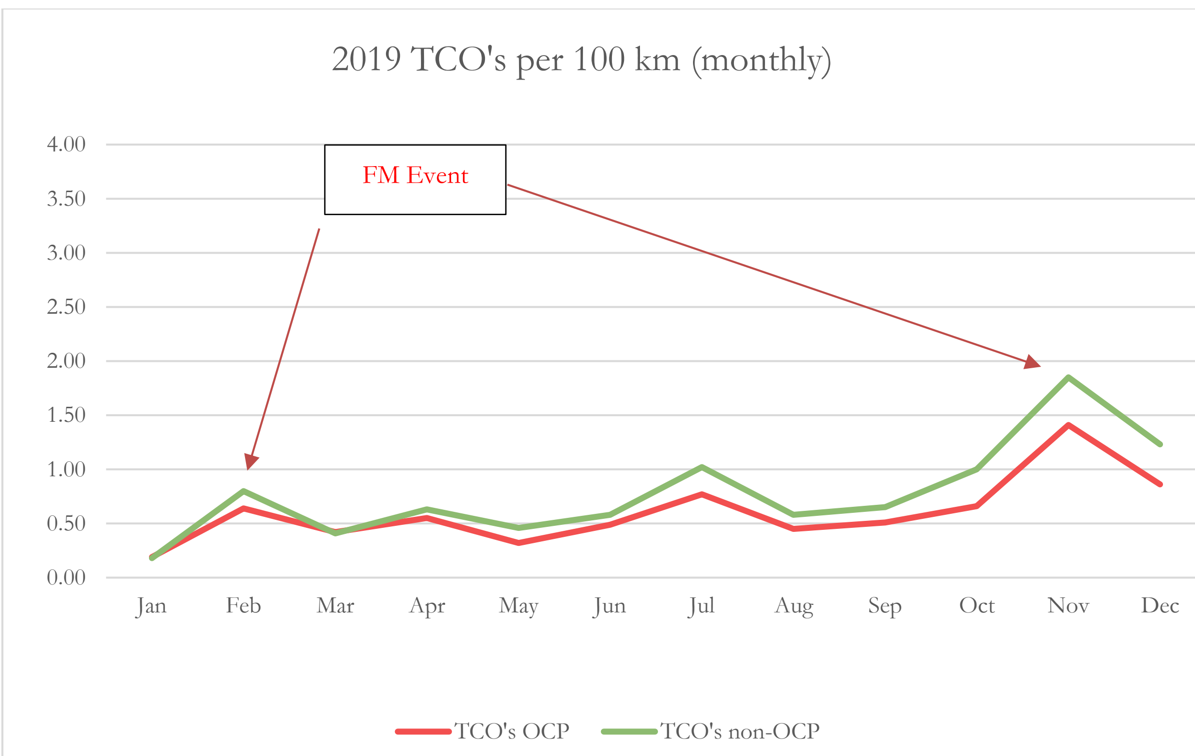


Figure 5 – 2020 TCO's OCP v. Non-OCP (including FM events)

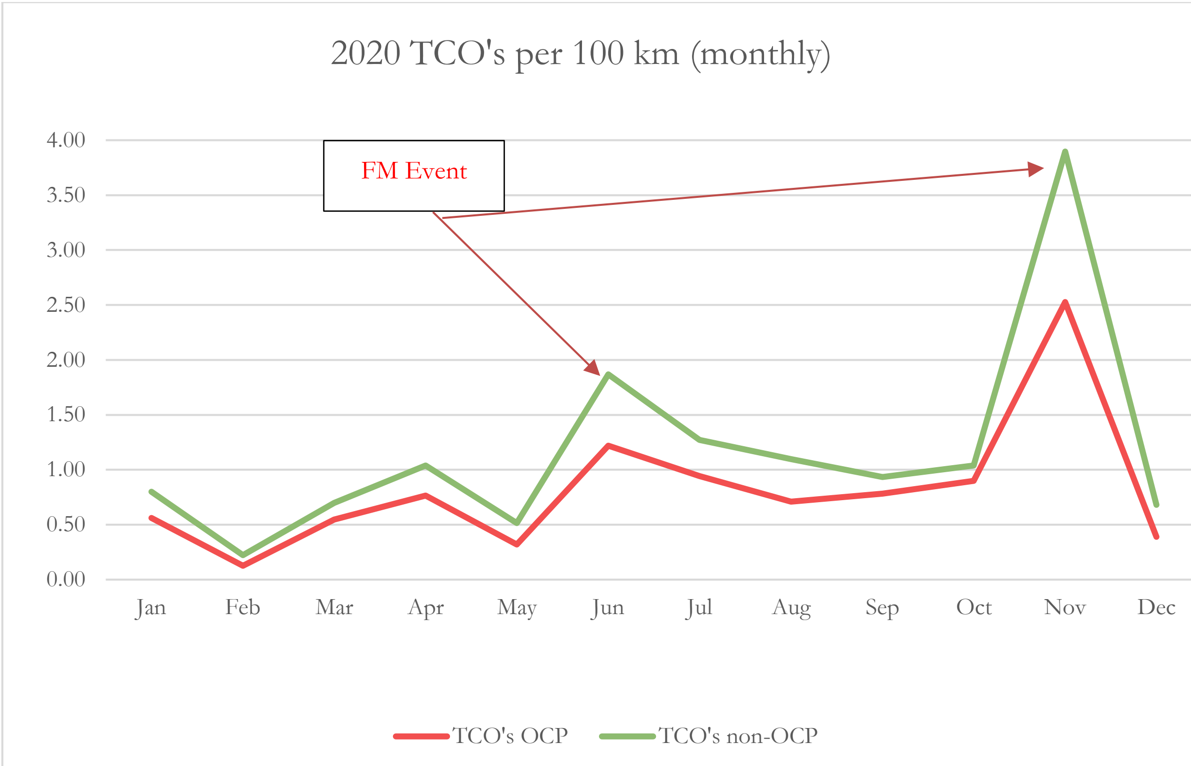


Figure 6 – 2018 TCO's OCP v. Non-OCP (including FM events)

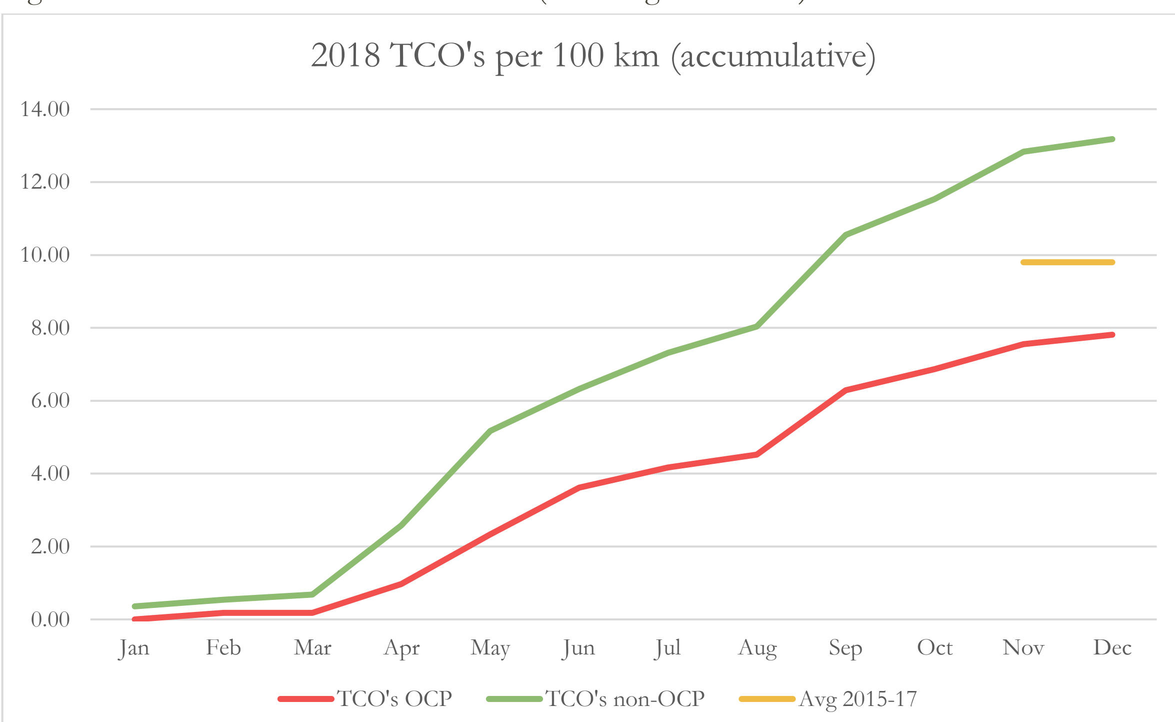


Figure 7 - 2019 TCO's OCP v. Non-OCP (including FM events)

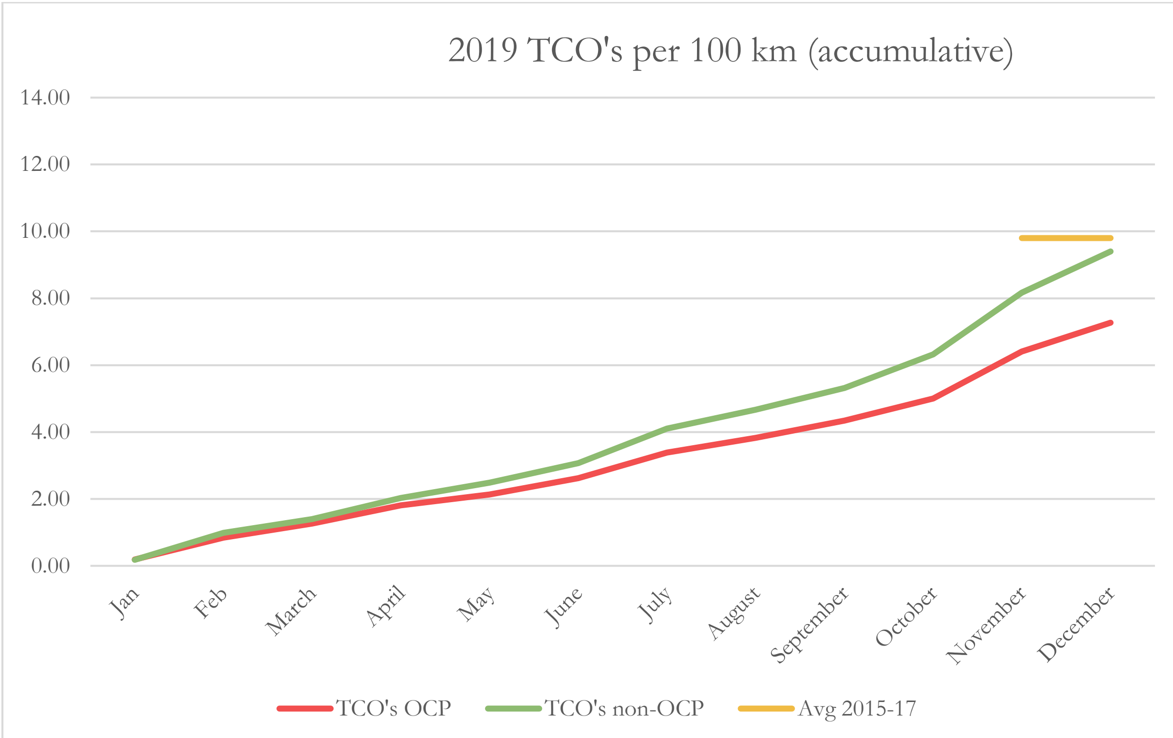


Figure 8 - 2020 TCO's OCP v. Non-OCP (including FM events)

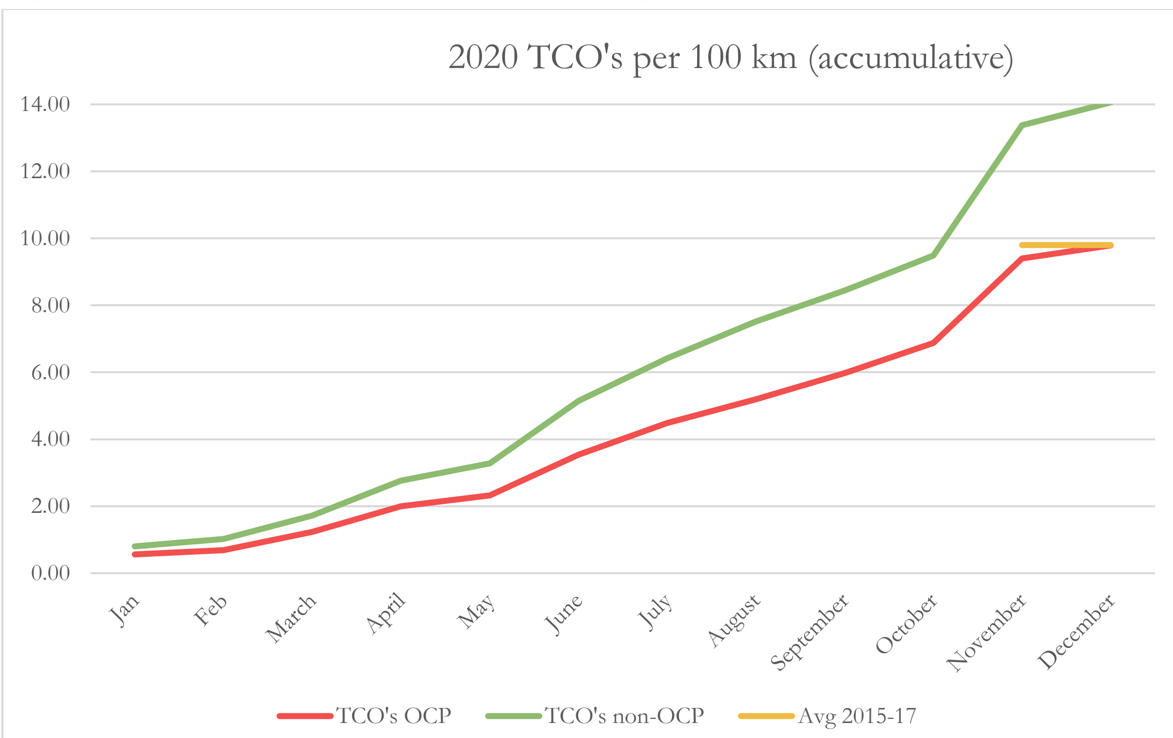


Figure 9 – 2018 TCO's OCP v. Non-OCP (excluding FM events)

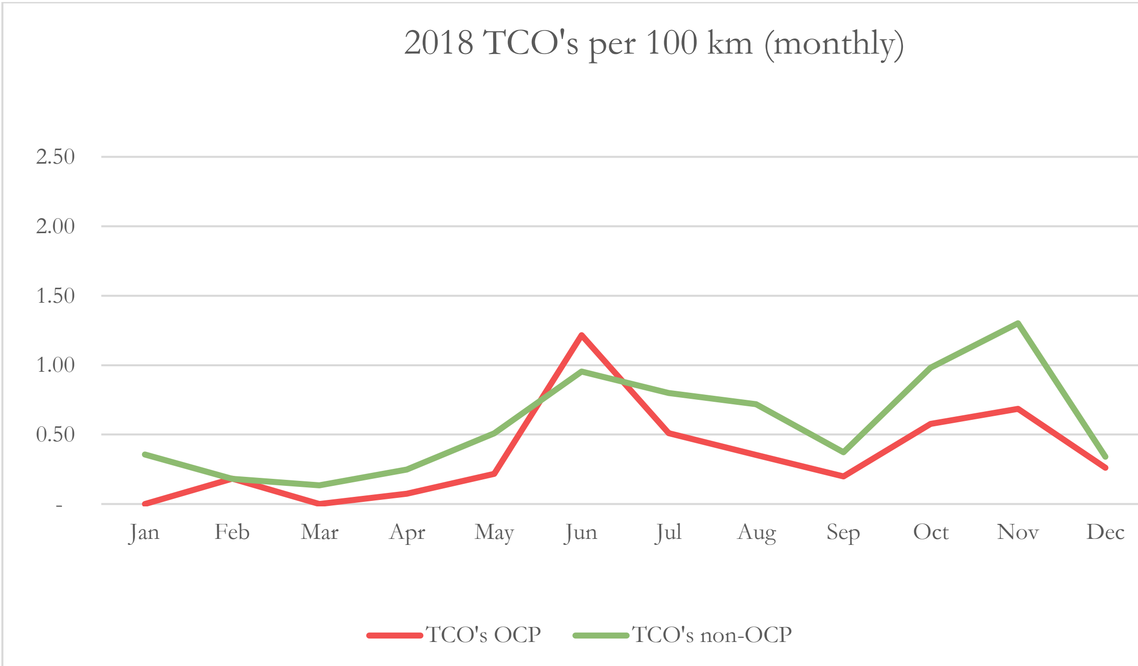


Figure 10 – 2019 TCO's OCP v. Non-OCP (excluding FM events)

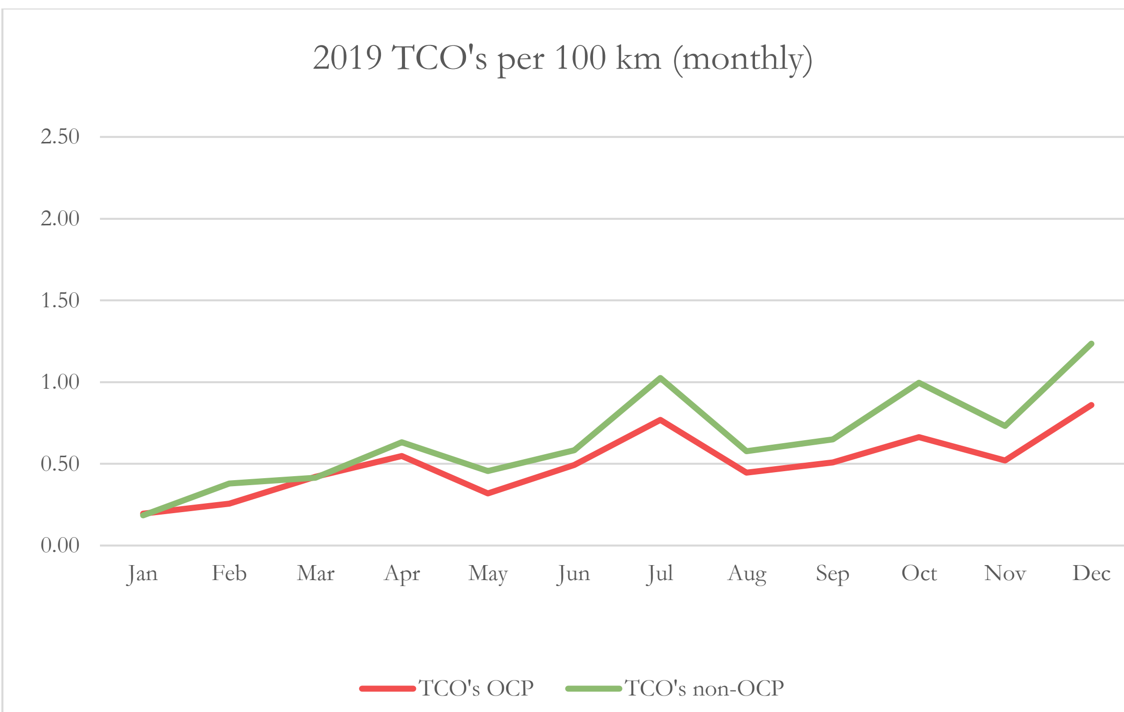


Figure 11 – 2020 TCO's OCP v. Non-OCP (excluding FM events)

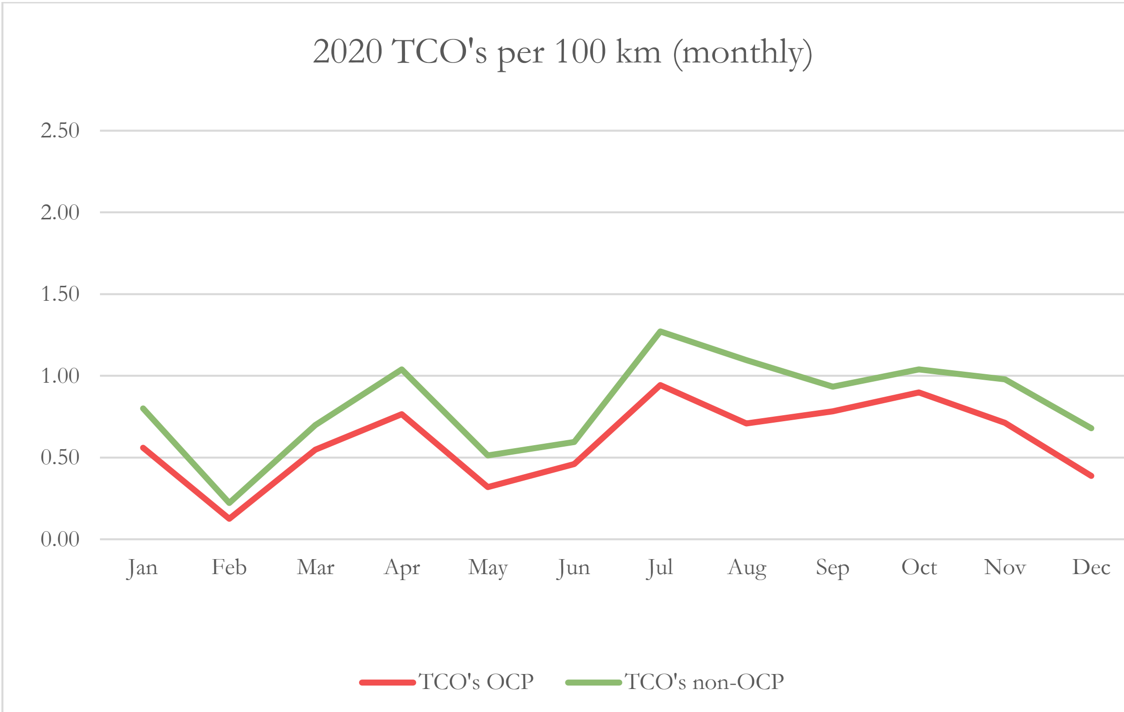


Figure 12 – 2018 TCO's OCP v. Non-OCP (excluding FM events)

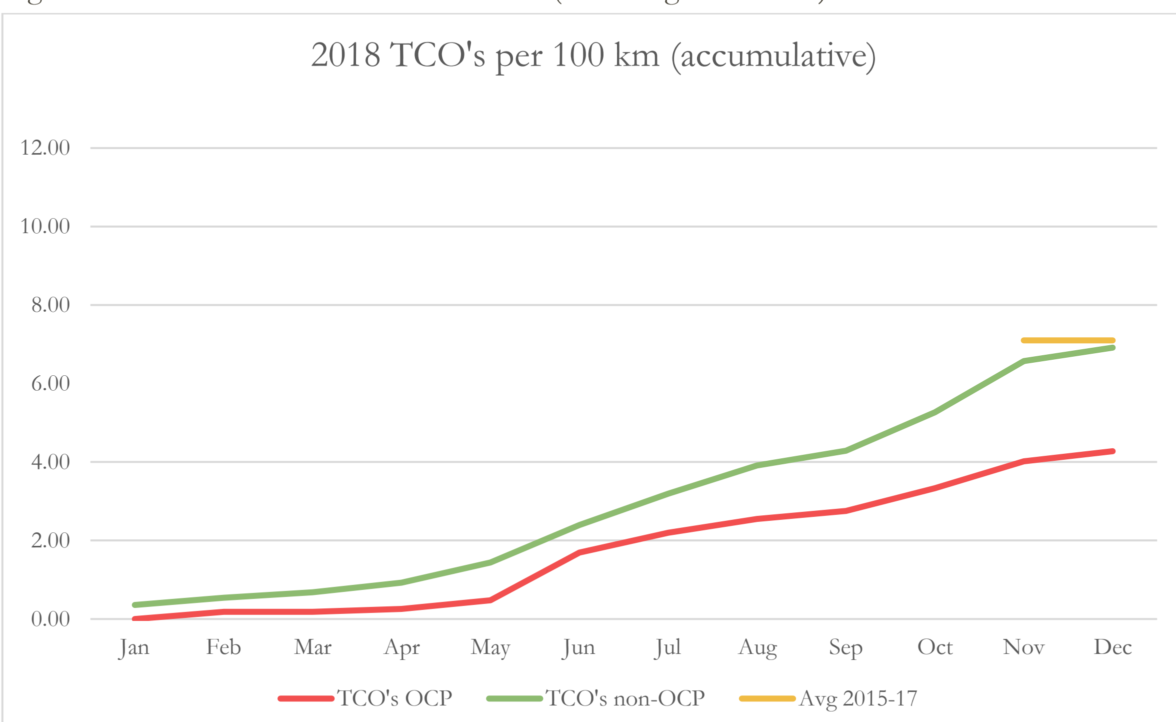


Figure 13 - 2019 TCO’s OCP v. Non-OCP (excluding FM events)

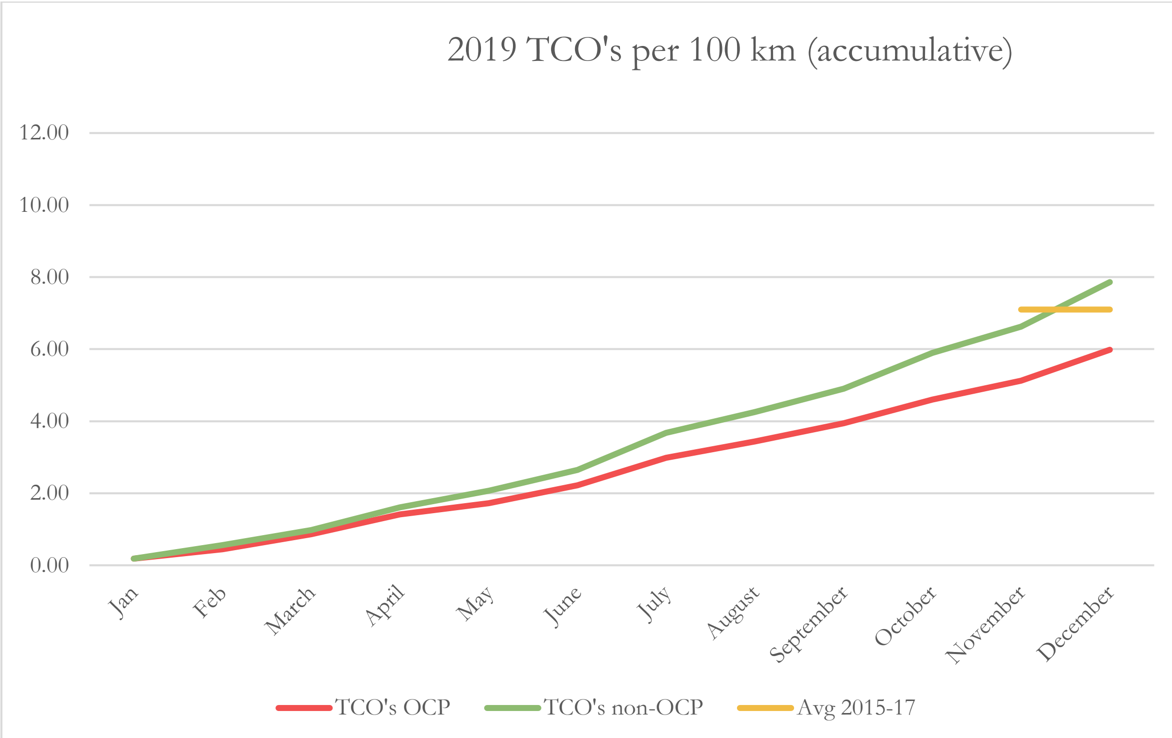
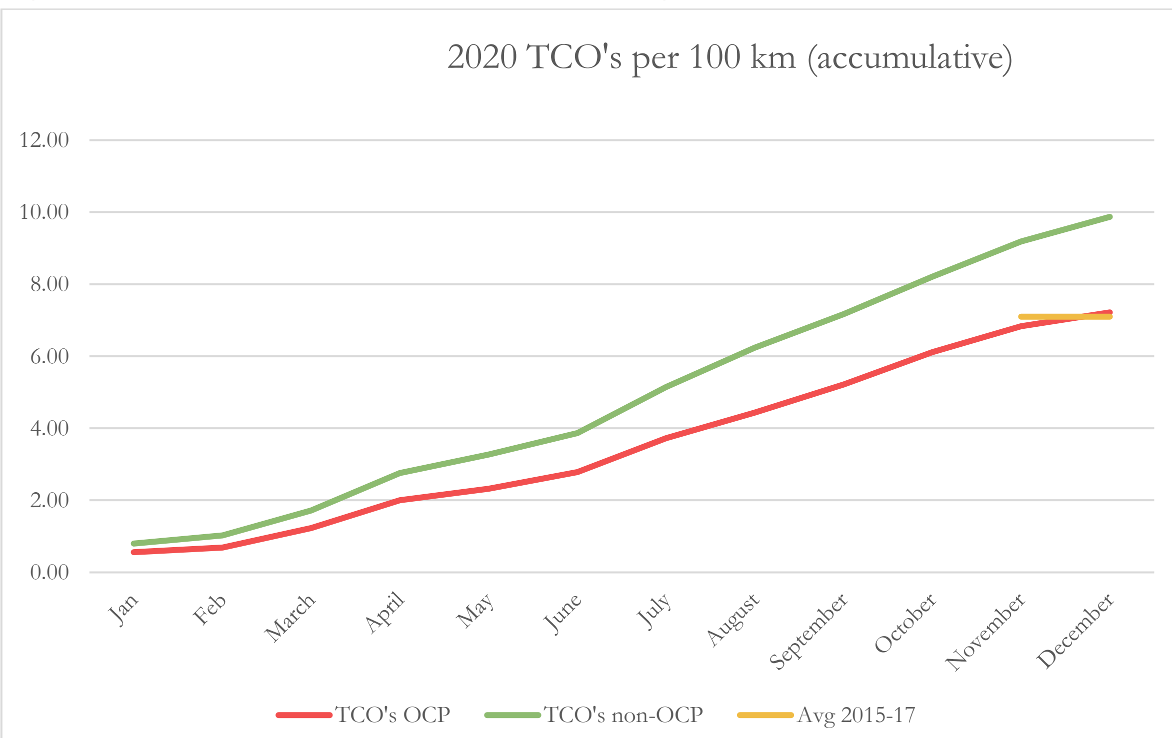


Figure 14 - 2020 TCO’s OCP v. Non-OCP (excluding FM events)



3.3 Conclusion

This analysis confirms a direct relationship between tree defects and reliability performance consistent with reliability modeling from the 2017 assessment.

- The differential (improvement) between pre and post OCP work clearly demonstrates how reducing defects improves reliability.
- The differential (improvement) is greater during FM events indicating OCP reduces the impact of major storm FM events to a greater extent than the reliability improvements on "blue sky" days.
- Reliability improvement projections of 20%-40%, from the 2017 assessment, have been achieved for feeders that have been cleared under OCP vs. feeders that have not, based on 2018 to 2020 actual performance. However, in an above average storm year such as 2020, OCP-completed feeders may not show reduced outage frequency as compared to a multi-year historical average but nevertheless still demonstrate far fewer outages than feeders where OCP work was not completed.

4. Workload Assessment

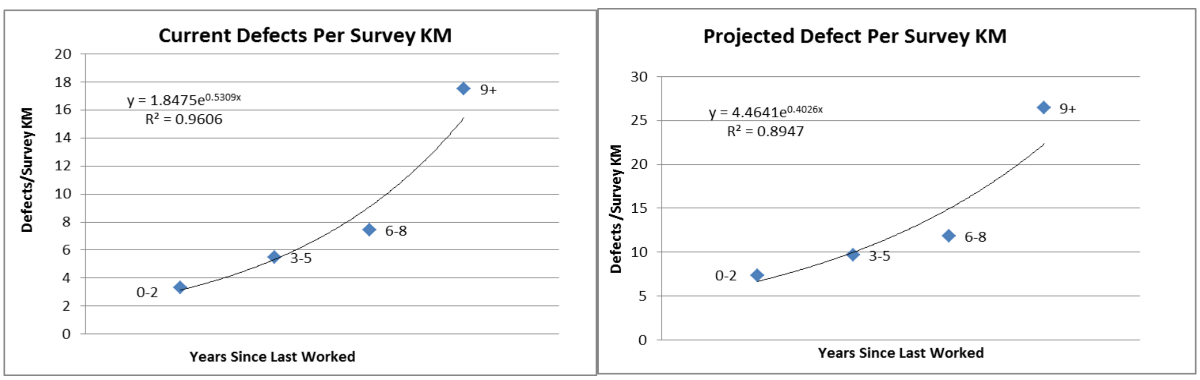
4.1 Workload Models from 2017 Assessment

First cycle workload projections from the 2017 assessment were estimated at 21 defects per km worked or roughly 2.1M trees across 103,998 km across the service area. The projected workload included an average of 8 existing defects per km at time of work and another 13 to prevent defects from occurring by the end of the first cycle (presumed to be 3 years at the time) and before start of the second cycle.

Table 8 – Current and Projected Workload (2017 Assessment by Zone and Work Class)

Combined Current and Projected Workload	Zone A	Zone B	Zone C	Zone D	Total Units of work
Contacts On-ROW	73,093	85,631	88,502	54,122	301,348
Contacts Off-ROW	94,597	94,463	83,488	48,135	320,683
Brush Contacts	41,175	102,430	111,500	120,519	375,625
Hazard Trees	129,408	243,165	517,607	199,193	1,089,372
Totals	338,273	525,689	801,097	421,969	2,087,028

Figure 15 – Current and Projected Workload (2017 Assessment by Slot Class)



4.2 OCP Defect Workload

First cycle defects identified for work (referred to as "notified" below) in the first three years of OCP (2018/2020) exceeded the 2017 projected numbers by 13% (see Table 9). At the slot class level (time intervals since last worked) variances between projected and actual ranged from 23% under to 22% over projections (shown in Table 10).

Table 9 – OCP Defects Notified 2018 - 2020

Notifications	Total	2017 Projection	Variance %
Defects Notified	2,093,198		
Kms notified	88,037		
Defect Density	23.8	21	13.2%

Table 10 –OCP Defects Notified 2018/2019 (time since last worked)

Slot Class (years)	KM	2017 per km Projection	per km Actual	Variance %
0 to 2	19,415	12	9.2	23
3 to 5	19,080	16	17.5	(9)
6 to 8	16,428	20	24.4	(22)
9 plus	15,382	44	46.0	(5)

4.3 Conclusion

The 2018-2020 defect workload (23.8) was 13% greater than the 2017 projection (21).

5. Unit Cost Assessment

There are two distinct unit cost measures (defects and km) and two work activities (notification and execution). Notification is a predecessor work activity and critical path to execution. Accomplishments associated with each may be different at any moment in time until the project is complete at which time they should be in sync.

Defect unit cost is a function of cost drivers (labour, equipment & material) and productivity. Kilometer unit cost is a function of defect unit cost and quantity (density per km).

5.1 Unit Cost Models from the 2017 Assessment

Average defect unit cost was projected at $164.72 per unit, averaged across all zones and unit types including notifications. Per km unit cost was derived by multiplying defect unit cost by a projected 21 defects per km (table 9) across the system, for a projected cost of $3,462 per km.

Unit defect cost models were based on several factors including:

- Cost history provided from Hydro One legacy systems.
- Industry benchmarking and local knowledge.
- Degree of difficulty production factors for different units of work.
- Projected distribution of work units by zone and degree of difficulty.

5.2 Unit Cost Performance

Tables 12 and 13 illustrate 3-year cost performance relative to the 2017 assessment projections.

Table 11– Unit Cost (defect worked) – Model v. Actual

Work Activity	Modeled Cost	Actual Cost	Variance $	Variance %
Notification	$14.29	$25.19	($10.90)	(76%)
Execution	$150.43	$194.40	($43.97)	(29%)
Total	$164.72	$219.59	($54.87)	(33%)
Contractor Execution (1)	$150.43	$157.00	($6.57)	(4%)

(1) *Note: Contractors performed 8.6% of the execution work included in the total execution numbers.*

Table 12– Unit Cost (km) – Model v. Actual

Work Activity	Projected Cost km	Actual Cost km	Variance $	Variance %
Notification	$303	$599	($296)	(98%)
Execution	$3,159	$4,685	($1,526)	(48%)
Total	$3,462	$5,284	($1,822)	(53%)

Note: Extrapolated cost from defect units does not line up due to timing variance between notification and execution.

5.3 Unit Cost Variance

There were several factors that influenced the actual versus projected cost.

5.3.1 Projections from 2017 Assessment

Projections in 2017 were based a set of assumptions and information available at the time including limited historical data from legacy systems, local knowledge, and industry benchmarks to determine unit defect cost. As OCP introduced a completely new model, many assumptions were not able to be tested. Factors that contributed to the variance include:

- Defect density per km in 2018-2020 was 13% greater than projected as described in Section 4, contributing $609 or 11.6% to the per km unit cost.
- Notification cost – Notification cost was modeled at $2.5Mper year, per zone. Actual cost 75% higher than the modeled cost. There were other factors involved as further described in this section.
- Distribution of units – the projection model assumed a 50:50 removal to trimming ratio to mitigate defects. Higher removal ratios are preferred for long term maintenance but have a higher degree of difficulty and thus higher one-time cost (Table 11). The actual removal to trim/prune ratio was 60:40 resulting in a higher one-time cost. However, benefits will be seen in future years as removed trees will not need to be worked again.
- Crew labour – costs were based on Hydro One labour rates and projected contract rates for industry standard 2-person crews with one utility arborist and one lower cost apprentice, climber, or ground person. Union agreements precluded the use of standard crew complements, thus increasing the labour cost.

5.3.2 Other Factors Contributing to Variances

OCP Start-up

As a new operating model, OCP required extensive training of existing staff and on-boarding training of new staff. Associated one-time cost was estimated at $3M - $5M, which was not included in the 2017 projection.

Changes to OCP Work Scope

- Brush work performed on sub-transmission M-Class (44kV) feeders not included in the cost models contributed approx. $7M (2.5%) to the execution cost.

New Technology Deployment

- Forestry Technology Enablement Project (FTEP) deployed in 2019 (in order to better support forestry work performance and associated work management processes) contributed an estimated $5M (9%) to notification and $5M (2%) to execution costs due to training and other operational impacts.

Contracting

Execution strategy included contracted resources to augment in-sourced crews at approx. $18M per year ($55M over a 3-year period). Contracting is approx. 19% less than in-sourced crews (Table 12). Less than $25M was spent on contracting due to various unanticipated constraints, which contributed to a $5.7M (2%) variance in the execution cost.

Significant Events

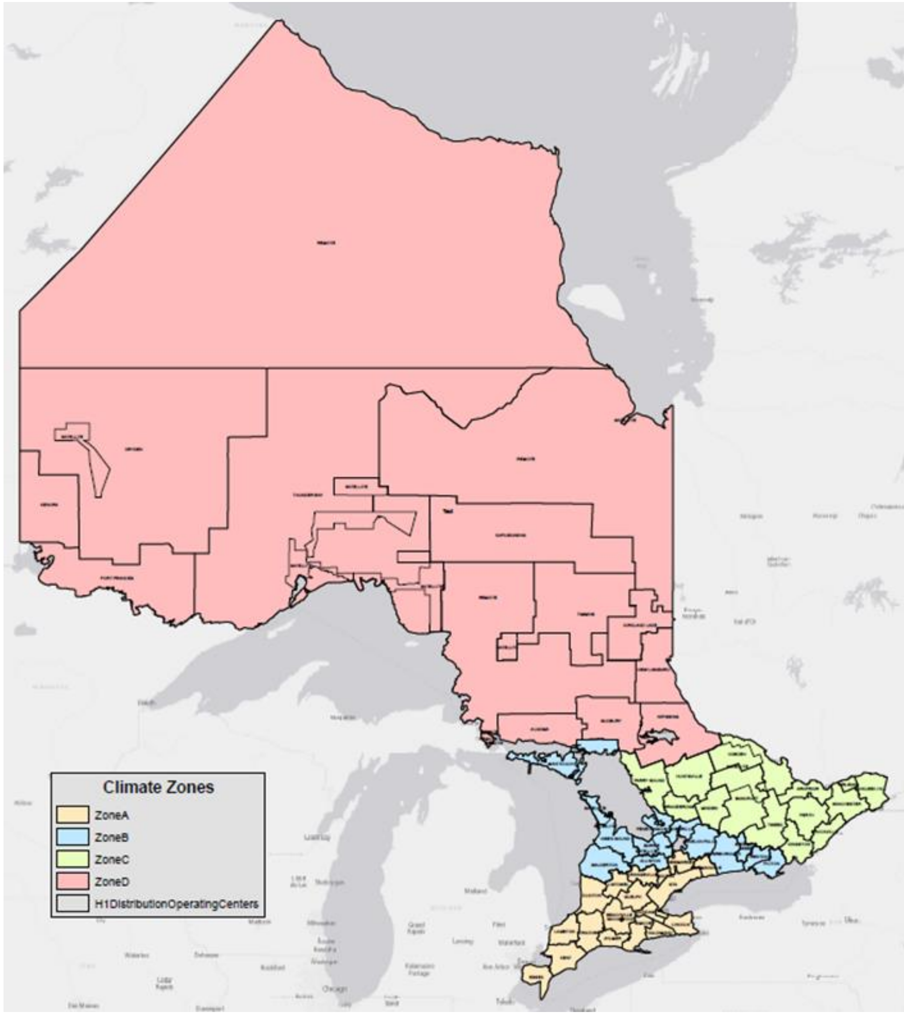
- Safety stand-down due to a major catastrophic event in 2019 impacting the entire forestry organization over 8 working days equating to a one year 4% loss in productivity and estimated $4.7M.
- The COVID-19 pandemic in 2020 impacted the entire organization, including the performance of forestry work.

5.4 Conclusion

Unit cost projections from 2017 were based on best available information and assumptions at the time, without being able to account for unanticipated factors that contributed to the higher actual cost:

- Defect workload density 13% higher than projected.
- Higher than projected notification, compounded by scope changes, technology deployment and significant events as noted.
- Scope changes relating to M-Class brush control.
- FTEP technology deployment.
- Higher ratio of removals to prune/trim.
- Less contracting than originally anticipated.

Appendix A – Climatic Zones



Climate Zones
A – Agriculture/Suburban, Southeasterly part of Ontario surrounding GTA
B – Rural Cottage Country/Agriculture**,** East Central Ontario, North of GTA
C – Rural/Forested, Northeast Ontario
D – Forested/Remote, Northwest Ontario

Trilliant

November 29, 2019

Kevin Marcotte
AMI Operations
Hydro One Networks Inc.
255 Matheson Blvd West
Mississauga, Ontario, L5R 3G3

RE: Expected Service Life

Dear Mr. Marcotte,

As part of our design strategy, Trilliant designs all products to operate for a period of 15 years. In support of this request, Trilliant commissioned an independent laboratory (Sector, based in France) to run an analysis of our RF radio based on the recognized Telcordia SR-332 process. The results support our predicted minimum service life of all Trilliant SecureMesh radios deployed within the Hydro One AMI network (15 years).

Based on our 25+ years of experience in managing metering and related components for the Ontario Market through our Measurement Canada approved facility, Trilliant suggests a more conservative approach in the replacement of metering equipment which is vital to the supply of heat and power to hundreds of thousands of customers in Ontario. A replacement cycle that supports up to and including the 15th year of service provides the correct balance of maximum service life while not compromising on security and safety of the service and is therefore in the full and best interest of the rate payer.

The statements contained in this note are not guarantees of future performance and undue reliance should not be placed on them. Such forward-looking statements necessarily involve known and unknown risks and uncertainties, which may cause the actual performance and longevity of the products in future periods to differ materially from any projections of longevity or future performance.

Regards,

Steven Lupo
Senior Vice President, Canada

CC: Pete Mitskos
CC: Mark Costas

Hydro Québec Distribution

Accelerated life testing of FOCUS ALF meters with Gen1 and Gen3 communications boards

Alexandre Lemire, Eng.

Expertise et Ingénierie, Hydro-Québec

September 15, 2020

Acknowledgements

We would like to thank Hydro One for the trust they placed in us and for their expertise in the field of metering. We hope to continue this enriching partnership in the future.

We extend special thanks to metering technician André Bourget for the invaluable expertise and meticulousness he brought to the entire project.

Note from the author:

Please note that throughout the report, the utilization of the decimal point was favored to reflect the usual terms used in English. Unfortunately, it has proven impossible to convert the spreadsheet from French to English. This is why most tables use the decimal commas instead.

Table of Contents

1 **Executive Summary** **1**
2 **Background** **4**
3 **Failure Analysis** **5**
3.1 Power failure 6
3.2 Display failure—Missing segments 8
3.3 Communication and association failure 12
3.3.1 GEN1 12
3.3.2 GEN 3 13
4 **Sample size and margin of error** **15**
5 **Quantification of life profile constraints** **17**
5.1 Climatic conditions in the Sarnia/Windsor area 17
5.1.1 Mean monthly temperature 17
5.1.2 Average relative humidity 17
5.1.3 Solar radiation 18
5.2 Climatic conditions, Sudbury area 20
5.2.1 Mean monthly temperature 20
5.2.2 Average relative humidity 20
5.2.3 Solar radiation 21
5.3 Average load of a residential meter 22
5.4 Electronic part self-heating 23
5.5 Temperature rise in the sun 26
5.6 Failure criterion 30
5.6.1 LCD 30
5.6.2 Communication 31
5.6.3 Capacitors 31
5.6.4 J1 connector 32
6 **Test selection and descriptions** **33**
6.1 HTOL 33
6.1.1 Objectives 33
6.1.2 Acceleration model 33
6.2 Temperature cycling 39
6.2.1 Objectives 39
6.2.2 Acceleration model 39
6.2.3 Calculations 40
6.3 Temperature and humidity 45
6.3.1 Objectives 45
6.3.2 Acceleration model 45
6.3.3 Calculation 45
7 **Results** **52**
7.1 HTOL (High Temperature Operating Life) 52
7.1.1 Communication failure 53

7.1.2 Power failure 55
7.1.3 LCD failure 56
7.2 Thermal cycles 57
7.2.1 Communication failure 60
7.2.2 Power failure 61
7.2.3 LCD 63
7.3 Temperature and humidity 64
7.3.1 Communication problem 68
7.3.2 Power problem 71
7.3.3 LCD 72
8 Weibull distributions 77
8.1 Input data to be used 77
8.2 Ranking of the time to failure 78
8.3 Reliability/unreliability estimates 78
8.4 Calculation of parameters 79
8.5 Results 82
8.5.1 HTOL 82
8.5.2 Thermal cycles 88
8.5.3 Damp heat 89
9 Conclusion 95
10 References 96
10.1 Accelerated Life Testing 96
10.2 Standards 97
10.3 Transformers 97
10.4 LCD 98
10.5 Contrast Sensitivity 99
10.6 Solder Crack 99
10.7 Weather 100

List of Figures

Figure 1. Capacitor C21 failure ... 3
Figure 2. Transformer with primary winding open ... 6
Figure 3. Analyzed LCDs with missing segments ... 8
Figure 4. Display without indication of manufacturer ... 9
Figure 5. Working meter—Drive voltage with segment off ... 10
Figure 6. Working meter—Drive Voltage with segment on ... 10
Figure 7. Defective meter—Drive voltage with segment off ... 11
Figure 8. Capacitor failures in GEN1 meters ... 12
Figure 9. J1 issue in GEN1 meters ... 13
Figure 10. Bracket added to reduce mechanical stress on the connector ... 14
Figure 11. Temperature readings during test ... 23
Figure 12. Summary of self-heating characterization results ... 24
Figure 13. Solar heating test apparatus ... 26
Figure 14. Temperature increase inside the meter and solar radiation during test ... 28
Figure 15. Graph of the mean value theorem for integrals ... 28
Figure 16. LCD colour measurement setup with template ... 30
Figure 17. JEITA RCR-2370B method for measuring capacitor capacitance ... 32
Figure 18. Temperature curve for thermal cycling ... 42
Figure 19. Internal temperature with polycarbonate cover ... 43
Figure 20. Internal temperature without polycarbonate cover ... 44
Figure 21. Meters at start of HTOL testing ... 52
Figure 22. Capacitors failures ... 54
Figure 23. FALCO transformer from J2074857 ... 55
Figure 24. Zettler Magnetics transformer from J3745300 ... 55
Figure 25. Missing segments on meter J2573239 ... 56
Figure 26. Missing segments on meter J2038889 ... 56
Figure 27. Meters 1 to 15 before the test ... 57
Figure 28. Meters 16 to 30 before the test ... 58
Figure 29. Temperature measured inside meters 1, 5, 8 and 11 ... 59
Figure 30. Condition of C21 on meter #10 – J2573411 ... 60
Figure 31. Cracked solder on connector J1 ... 60
Figure 32. XFO failure on meter #19 – 2970501 ... 61
Figure 33. XFO failure on meter #20 – J3322671 ... 61
Figure 34. XFO failure on meter #17 – J2965534 ... 62
Figure 35. Spots observed on LCDs ... 63
Figure 36. Meter testbed in environmental chamber for damp heat testing ... 64
Figure 37. Meters 1 to 15 after the test ... 65
Figure 38. Meters 16 to 30 after the test ... 65
Figure 39. Temperature and humidity from March 9 to March 24, 2020 ... 65
Figure 40. Temperature and humidity from May 13 to May 26, 2020 ... 66
Figure 41. C7 in J2076164, C7 in J2200102 and C21 in J2200748 ... 68
Figure 42. Cracked solder on connector J1 ... 70
Figure 43. Failed Zettler transformer ... 71
Figure 44. LCDs in GEN 1 meters ... 72
Figure 45. Detached and darkened top polarizing filter ... 73
Figure 46. LCDs in GEN3 meters ... 74
Figure 47. Meter J2970555 with missing segments ... 76
Figure 48. Meter J2965870 with missing segments ... 76
Figure 49. Weibull curves for communication failure in HTOL ... 82
Figure 50. Weibull curves for capacitor failures in HTOL ... 85
Figure 51. Weibull curves for LCD failure in damp heat ... 89
Figure 52. Weibull curves for capacitor failures in Damp Heat ... 92

List of Tables

Table 1. Sample size per test with associated margin of error and confidence level 1
Table 2. Acceleration factor for Windsor 1
Table 3. Acceleration factor for Sudbury 2
Table 4. Time to failure (hours) for communication board in GEN1 meters when exposed to HTOL 2
Table 5. Summary of Hydro One report findings 5
Table 6. Meters analyzed in Hydro-Québec's failure investigations 5
Table 7. Z-score by confidence level 15
Table 8. Sample size selected for each test 16
Table 9. Canadian Climate Normals station data, 1981 to 2010 17
Table 10. Canadian Climate Normals station data, 1981 to 2010 17
Table 11. Mean monthly temperature rise from the sun, Sarnia/Windsor 18
Table 12. Monthly sunshine duration data 19
Table 13. Canadian Climate Normals station data, 1981 to 2010 20
Table 14. Canadian Climate Normals station data, 1981 to 2010 20
Table 15. Mean monthly temperature rise from the sun, Sudbury 21
Table 16. Monthly sunshine duration data 21
Table 17. Number of customers and average consumption by rate 22
Table 18. Summary of self-heating characterization test results 24
Table 19. Measured solar panel efficiency 27
Table 20. Windsor ALT data for capacitor in HTOL 35
Table 21. Sudbury ALT data for capacitor in HTOL 35
Table 22. Windsor ALT data for transformer in HTOL 36
Table 23. Sudbury ALT data for transformer in HTOL 36
Table 24. Windsor ALT data for LCD in HTOL 37
Table 25. Sudbury ALT data for LCD in HTOL 37
Table 26. Windsor ALT data for solder in change of temperature 41
Table 27. Sudbury ALT data for solder in change of temperature 41
Table 28. Absolute humidity in g/m3 for certain air temperatures as a function of relative humidity 46
Table 29. Windsor ALT data for capacitor in damp heat 47
Table 30. Sudbury ALT data for capacitor in damp heat 48
Table 31. Windsor ALT data for LCD in damp heat 49
Table 32. Sudbury ALT data for LCD in damp heat 50
Table 33. HTOL failure log 53
Table 34. Capacitance of capacitor C21 during the HTOL test 54
Table 35. Log of failures during thermal cycle testing 59
Table 36. Failures logged during damp heat test 67
Table 37. Capacitance of capacitor C21 and C35 69
Table 38. LCD contrast during damp heat testing 75
Table 39. Reliability estimate for sample size N=19 and N=11 79
Table 40. Acceptance threshold by number of failures 81
Table 41. Communication failure in HTOL – Weibull distribution with confidence level of 50% 83
Table 42. Communication failure in HTOL – Weibull distribution with confidence level of 5% 83
Table 43. Communication failure in HTOL – Weibull distribution with confidence level of 95% 84
Table 44. Capacitor failure in HTOL – Weibull distribution with confidence level of 50% 86
Table 45. Capacitor failure in HTOL – Weibull distribution with confidence level of 5% 86
Table 46. Capacitor failure in HTOL – Weibull distribution with confidence level of 95% 87
Table 47. LCD failure in damp heat – Weibull distribution with confidence level of 50% 90
Table 48. LCD failure in damp heat – Weibull distribution with confidence level of 5% 91
Table 49. LCD failure in damp heat – Weibull distribution with confidence level of 95% 91
Table 50. Capacitor failure in damp heat – Weibull distribution with confidence level of 50% 93
Table 51. Capacitor failure in damp heat – Weibull distribution with confidence level of 5% 93
Table 52. Capacitor failure in damp heat – Weibull distribution with confidence level of 95% 94

1 Executive Summary

Hydro One commissioned Hydro-Québec to perform accelerated life testing on their Focus ALF meters equipped with GEN1 and GEN3 communications boards to determine the remaining service life of its meter fleet. A fault analysis was performed and 3 main failure modes were identified: power failure, display failure, and communication failure. Three accelerated life tests were selected based on these 3 failure modes.

- HTOL (High Temperature Operating Life): 2400 hours at 85°C was selected to address failure mechanisms accelerated by temperature that are primarily caused by the following phenomena: plastic aging, volatile compound deposit, material dilation, contact degradation and material aging.
- Damp heat: 600 hours at 85°C/85% RH was selected to address failure mechanisms accelerated by temperature and humidity such as material degradation by corrosion and migration phenomena that could cause electrical leakage or short-circuits.
- Temperature cycling: 700 cycles of 80 minutes from -40°C to +85°C was selected to address failure mechanisms accelerated by rapid change of temperature such as: solder joint aging (cracks), interconnection degradation, copper degradation, material dilation and creep.

The following quantities of meters were chosen by mutual agreement to decrease the margin of error while taking into account climate chamber space constraints. Individual meters to test were randomly selected from the population.

Meter Type	Population	Sample size (per test)	confidence level	margin of error
L&G Focus ALF Gen 1 (Form 2S)	661000	19	80%	15%
L&G Focus ALF Gen 3 (Form 2S)	476000	11	80%	20%

Table 1. Sample size per test with associated margin of error and confidence level

The Ontario climate was analyzed using two geographic reference points (Windsor and Sudbury) to determine the acceleration factors for each failure mechanism in each environment.

Windsor	Capacitor	transformer	LCD	solder
HTOL	20	2,5	57	
Temperature cycling				13,4
Damp Heat	153		579	

Table 2. Acceleration factor for Windsor

Sudbury	Capacitor	transformer	LCD	solder
HTOL	26	2,8	80	
Temperature cycling				13,5
damp heat	164		849	

Table 3. Acceleration factor for Sudbury

Table 4 present observed communication board times to failure (TTF) for GEN1 meters in HTOL. The three columns U5%, U50% and U95% are the unreliability with a confidence level of 5%, 50% and 95%. U50% also known as the median rank is the true probability of failure and the closest value to the actual results obtained during testing. This value is recommended to be used in estimating remaining life of the meter. The unreliability can be defined as the percentage of the population that will fail at a certain time. For example, based on table 4, we expect 20% of the meters to have a communication failure after 995h in the HTOL test with a confidence level of 50%.

Unreliability (%)	TTF(U5%)	TTF(U50%)	TTF(U95%)
10	312	662	1154
20	545	995	1508
30	774	1283	1783
40	1011	1560	2027
50	1269	1842	2260
60	1563	2143	2496
70	1916	2486	2752
80	2378	2911	3052
90	3106	3537	3468

Table 4. Time to failure (hours) for communication board in GEN1 meters when exposed to HTOL

It is important to note that on GEN1 meters, communication failures are associated with the failure of capacitor C21.

Figure 1. Capacitor C21 failure

During all testing, meters remained within their accuracy class, and at no time were metering errors observed.

In conclusion, accelerated life testing and failure analysis showed that super capacitors are among the first components to fail in the meters under analysis. This issue is more apparent in GEN1 since capacitor C21 is essential to the proper operation of the communication board.

Furthermore, failure analysis revealed a weakness in connector J1 for GEN3 meters, particularly prior to the introduction of the mount that reduces mechanical stress on the connector. However, among the samples randomly chosen for analysis, only one did not have the mount. That meter was the only one found to have failed. We must therefore express our reservations regarding the absence of GEN3 meter failures since the sample population subjected to thermal cycle testing did not contain enough meters without the mount to draw any significant conclusions.

2 Background

Hydro One began its smart meter rollout in 2007. Its fleet now consists of 1.3 million residential meters. In the past 12 months, the smart meter failure rate has increased significantly. Faced with this premature deterioration, Hydro One needed to evaluate the remaining service life of their meters to develop a replacement plan.

Hydro-Québec, which is recognized internationally for its metering expertise, was approached by Hydro One to submit a bid for accelerated life testing. Hydro-Québec's bid was selected because the company had previously performed this kind of testing and presented its results at an international conference on metering.

Two meter models were tested: the L+G Focus ALF with the Trilliant GEN1 communications board and the L+G Focus ALF with the Trilliant GEN3 communications board. The smart meter installed base counts about 615,000 GEN1 units and 375,000 GEN3 units.

Since service life data cannot be collected by testing under normal operating conditions, accelerated aging testing must be used.

In accelerated life testing, samples from a population are operated beyond their normal operating limits by applying stressors to reduce time to failure without introducing any new failure mechanisms.

Evaluating service life characteristics consists of recording and analyzing the failures that occur in accelerated testing, determining the distribution of those failures under the test conditions, and extrapolating this distribution to normal operating conditions using service life constraint models.

This method produces quantitative results with confidence interval limits.

3 Failure Analysis

In the preparation of “Test Report: 2S Meter Replacement Evaluation,” Hydro One evaluated 293 meters (primarily with the GEN1 communications board), representing a sample of the defective meters returned from the field. The report identified the different failure modes and their prevalence in the population of defective meters. Table 5 summarizes the report’s conclusions.

	Power		Display		Communication		Association		Functional meter		
	failure	%	failure	%	failure	%	failure	%	number	%	Total
Focus ALF	6	2%	103	35%	152	52%	6	2%	26	9%	293

Table 5. Summary of Hydro One report findings

The electronics circuits were analyzed to better understand the failure mechanisms involved, Hydro One provided 40 meters to Hydro-Québec for this purpose. Of those, 10 were working (8x GEN3 and 2x GEN1) and 30 were defective. Table 6 summarizes the number of meters analyzed by Hydro-Québec.

	New/Working	POWER	Display	Communication	Association
GEN 1	2	4	4	4	2
GEN 3	8	4	4	4	4

Table 6. Meters analyzed in Hydro-Québec’s failure investigations

Hydro-Québec conducted a series of tests to determine the cause of failure for each meter:

- Accuracy tests
- Communication tests
- Load profile and register verification
- LCD discolouration measurement
- Super capacitor characterization
- Electronic circuit analysis

I

It is important to note that **<u>all meters analyzed, when operating, were within their accuracy class and the metrology data integrity was present</u>** (from the meter to the manufacturer-supplied testing tools). The results, broken down by failure mode identified by Hydro One in TR-0001, are summarized in the following sections.

3.1 Power failure

The eight meters with a power supply problem (4 GEN1 and 4 GEN3) all had the same symptoms:

- Display blank
- Status LED off
- No communication with the meter

An analysis of the internal components of these meters found that all units had failed in the same way: the primary winding of the meter's supply transformer was open. Power was therefore not being supplied to the meter, rendering it inoperative. In some cases, a slight bulge was observed in the transformer. To check whether the transformer was the only affected component, the DC bus of each meter was powered directly at the rated voltage. Seven of the eight meters operated normally and the supply current was identical to an operating meter. However, one GEN1 meter (J2178620) was drawing 100 times more current than normal due to a fault on the communications board. Capacitor C22 was short-circuited and was destroyed the first time it was powered by the DC source. Once the communications board was removed, current draw returned to normal.

In seven out of eight analyzed cases, the transformer was the only faulty meter component. In one out of eight cases, the communications board was faulty, which could have led to the transformer fault.

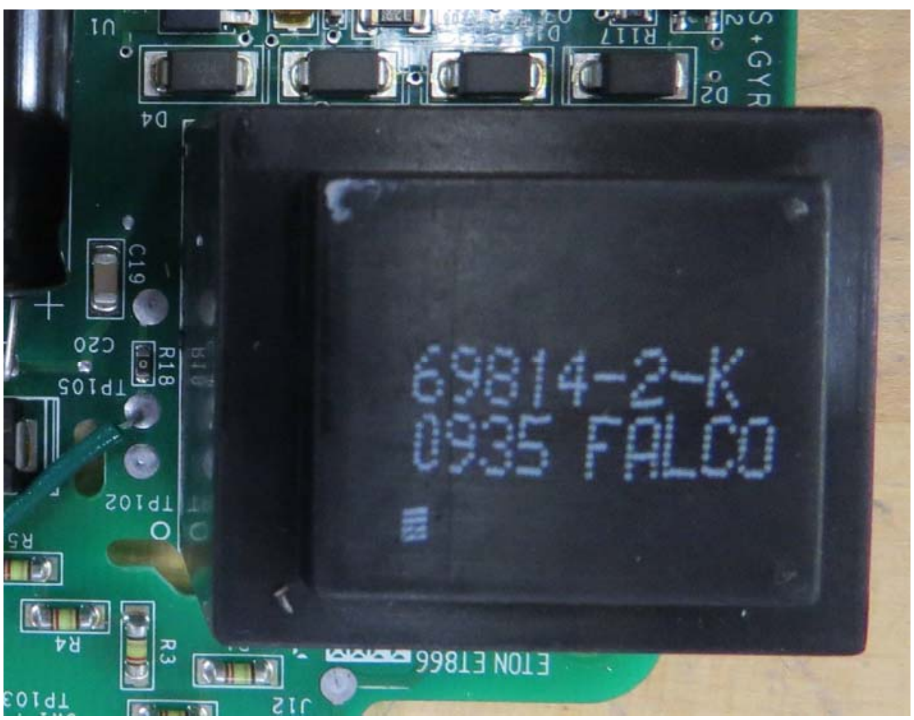


Figure 2. Transformer with primary winding open

It is noteworthy that all eight meters examined had the same FALCO transformer. According to Hydro One, the manufacturer changed suppliers and switched to a transformer made by PULSE in about 2010. Thus, we assume that the population at risk corresponds to meters manufactured before 2011. This represents approximately 661,000 GEN 1 meters and 150,000 GEN3 meters.

3.2 Display failure—Missing segments

Eight meters (4 GEN1 and 4 GEN3) were analyzed in Montréal for this failure mode. Figure 3 shows the different display failures observed. One of the four GEN3 meters was not displaying anything upon receipt, but a broken J1 connector was identified. Once repaired, the display operated normally. This meter was therefore excluded from the analysis since it was not representative of the fault.

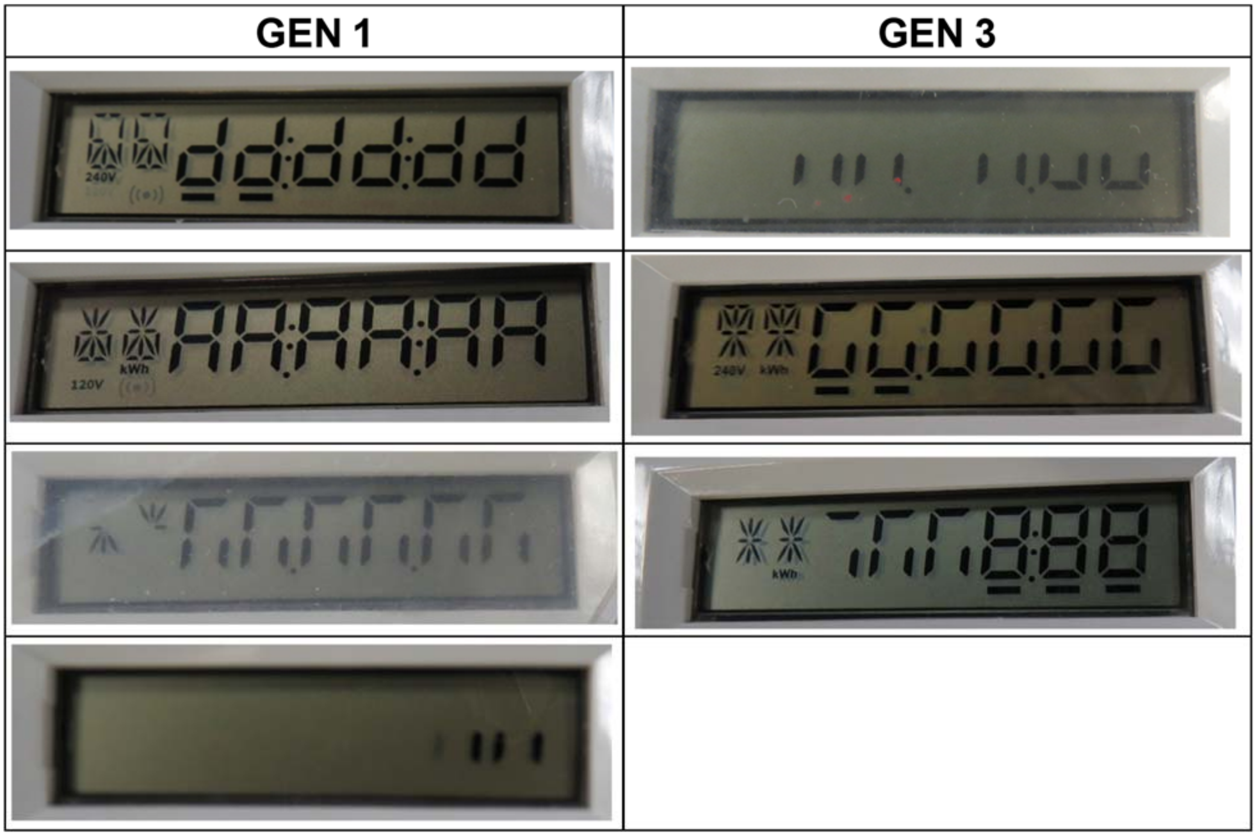


Figure 3. Analyzed LCDs with missing segments

The analysis performed by HQ consisted of swapping display components one at a time into a functioning meter to isolate the defective components. This revealed that in six out of seven cases, the LCD was the sole cause of the fault. In one case out of seven (GEN1), both the LCD and its power supply circuit were defective.

In the GEN1 units, none of the four defective displays had any indication of the manufacturer or model. Note that three different types of displays were identified for this generation (OKAYA, D-TV20665A-00 and no identification).

Figure 4. Display without indication of manufacturer

For GEN3, three defective displays were examined. Two were manufactured by OKAYA and one was only identified as 72065-3 3.3V TB9978C (R) 1405016 without any indication of the manufacturer.

Figures 5 and 6 show the Segment On and Segment Off voltages for a meter with a functioning display. Figure 7 shows the voltage waveform for the meter with a defective power supply circuit.

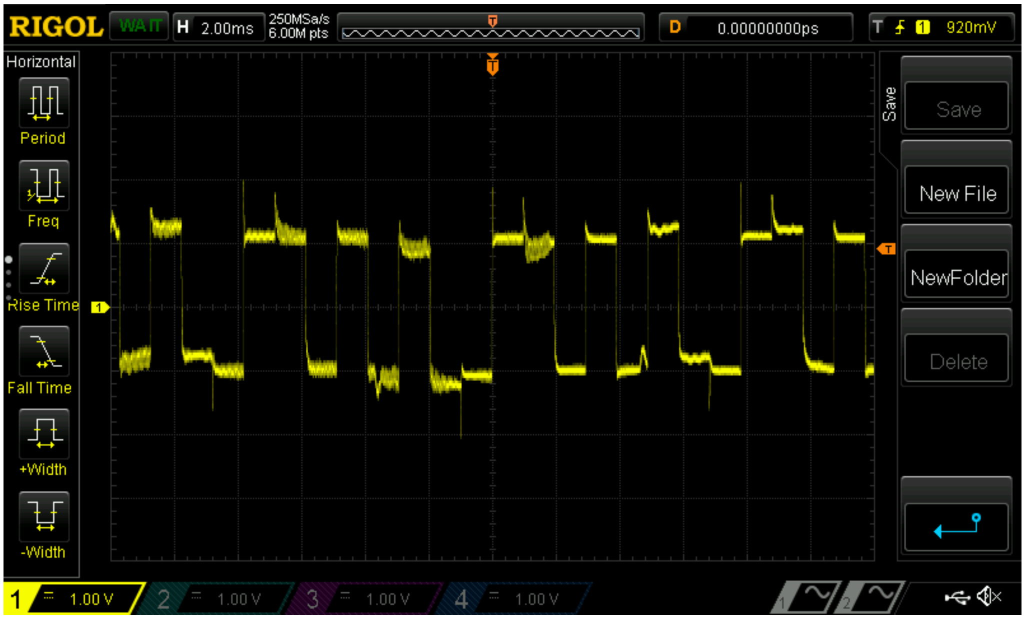


Figure 5. Working meter—Drive voltage with segment off

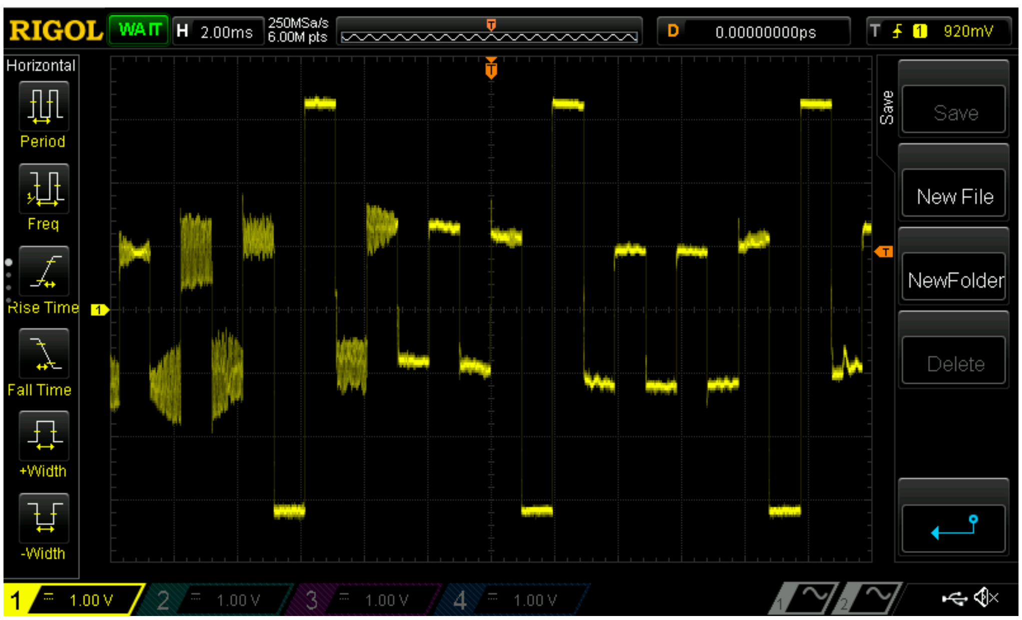


Figure 6. Working meter—Drive Voltage with segment on

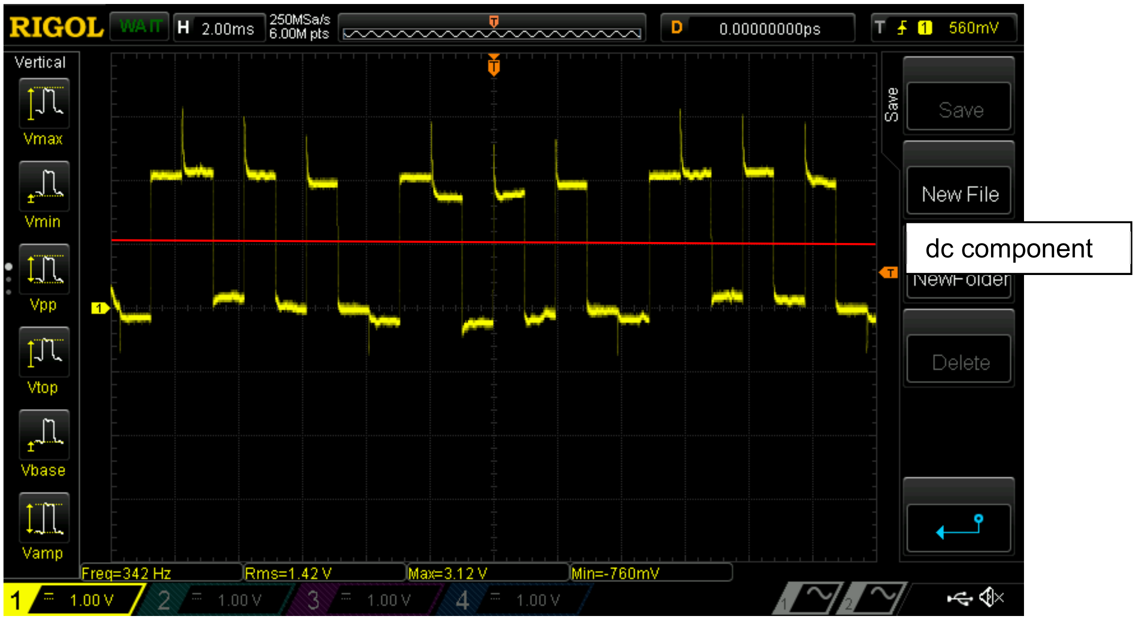


Figure 7. Defective meter—Drive voltage with segment off

Note the presence of a DC component in Figure 7. LCDs are very voltage-sensitive and always require an alternating current supply. The detected direct current could therefore have caused the LCD's failure. Conversely, it is possible that deterioration of the LCD caused a fault in the power supply circuit. More in-depth analysis would be needed to answer this question. However, given the time constraints and the low prevalence of the problem, the LCD was considered to be the most likely cause.

During Hydro-Québec's visit to Hydro One, 61 defective meters were analyzed. Of those, 25 were GEN1 and 36 were GEN3. A display fault was observed in 14 out of 25 GEN1 units and five out of 36 GEN3 units.

According to information provided by Hydro One, a population of about 116,000 meters is at risk of this failure.

3.3 Communication and association failure

3.3.1 GEN1

The communications board in the meters uses three super capacitors for various purposes. According to Hydro One, C2 is used for RTPO, C7 to back up data and C21 to provide energy for radio transmission.

Of the 16 meters with a GEN1 communications board analyzed by Hydro-Québec, 15 showed signs of electrolyte leakage from at least one of three capacitors, representing 94% of the meters analyzed. In a subsequent analysis with Hydro One, 25 meters were randomly chosen from a population of defective meters to increase the sample size. Of them, 23 had signs of electrolyte leakage, representing 92% of the meters.

Figure 8. Capacitor failures in GEN1 meters

Special tests on the GEN1 meters confirmed that the loss of capacitor C21 prevents the radio from communicating. In contrast, the GEN3 card behaves differently. The loss of the capacitor (C35 for GEN3) will only limit radio range, but will not disable communication altogether.

In summary, the failure of C2 or C7 will result in the loss of functionality but will not render the meter inoperable. However, capacitor C21 is vital to the proper operation of GEN1 meters, which is why, unlike C2 and C7, we analyze its degradation in detail during climatic testing.

Given the high prevalence observed, we assume that the entire population of Focus ALF GEN1 meters—612,000 units—are at risk of developing this problem.

3.3.2 GEN 3

Of the eight meters with an association or connection problem, six had cracked solder joints on connector J1, which connects the metrology board to the communications board. Once the solder joints were repaired, all meters communicated properly, demonstrating that the solder joints were the problem.

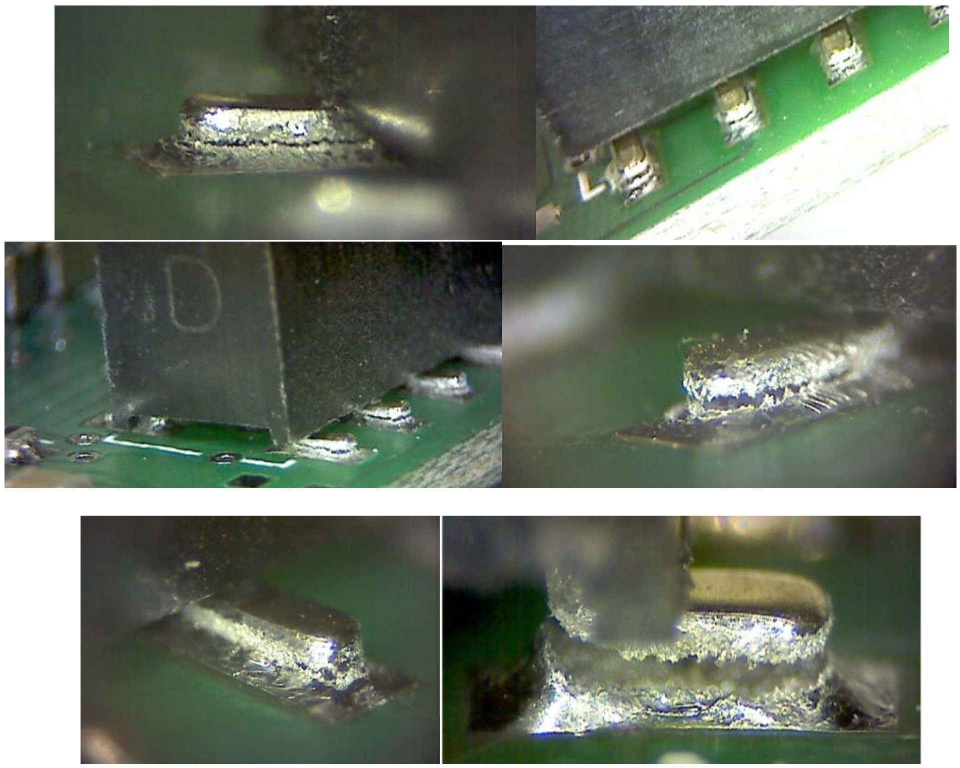


Figure 9. J1 issue in GEN1 meters

It was also observed that this problem can be intermittent since cracked solder can continue to make contact. This can sometimes make it difficult to interpret diagnostics performed with the manufacturer's tools.

In some GEN3 meters, the metrology board and the communications board were found to be misaligned. This misalignment puts mechanical stress on connector J1, which could explain its premature failure. The manufacturer appears to have resolved the problem because a tripod bracket was added later in production (see Figure 10).

During HQ's visit to the Hydro One offices, 36 meters were randomly chosen from a population of defective meters. Of those, 20 meters had at least one cracked solder joint on connector J1.

Abrupt temperature change testing will make it possible to determine if environmental stressors contributed to accelerating this failure.

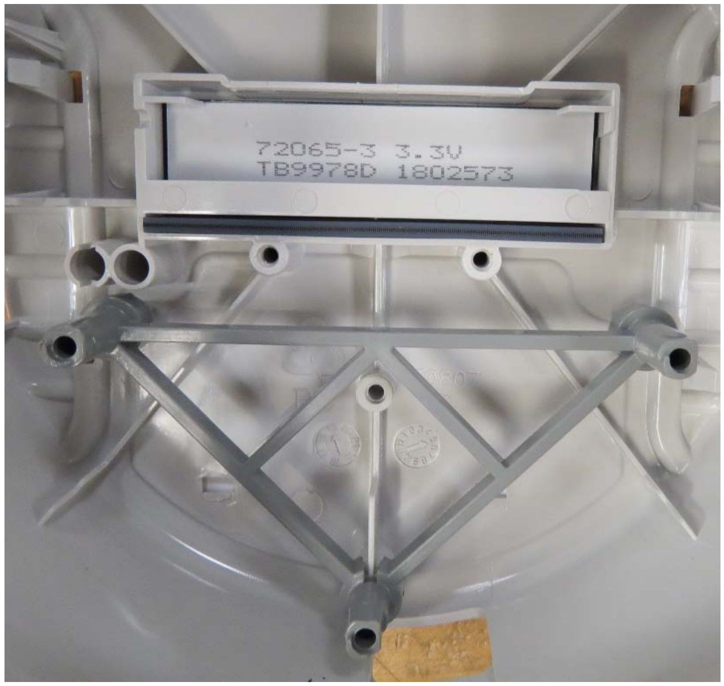


Figure 10. Bracket added to reduce mechanical stress on the connector

According to information provided by Hydro One, Gen 3 meters were recalled to add the tripod.

4 Sample size and margin of error

In statistics, a compromise must always be found between the acceptable margin of error and the effort needed to increase the sample size. In this case, one of the main limiting factors was the size of the available climate chambers and the testing time required each week to monitor the progress of the meters. Furthermore, since three tests were being performed, the number of meters to analyze each week was tripled.

After analyzing the possible configurations in the climate chamber, we determined that 30 is the maximum number of meters that could be simultaneously powered in a single chamber while respecting the minimum distance from the walls.

The following equation was used to calculate sample size and the associated margins of error[1].

$$\text{Sample size} = \frac{\dfrac{z^2 \times p\,(1-p)}{e^2}}{1 + \left(\dfrac{z^2 \times p\,(1-p)}{e^2 N}\right)}$$

Where

N = population size
e = Margin of error (percentage in decimal form)
z = z-score
p = estimated proportion of population with defect

Z-score is given in table 7

Desired confidence level	z-score
80%	1.28
85%	1.44
90%	1.65
95%	1.96
99%	2.58

Table 7. Z-score by confidence level

[1] https://www.surveymonkey.com/mp/sample-size-calculator/

Note that software[2] was used to simplify calculations.

Table 8 shows the sample sizes selected jointly by Hydro-Québec and Hydro One. They are compatible with the space constraints of the climate chambers and the time the assigned Hydro-Québec resources could allocate to the project.

Meter Type	Population	Sample Size (per test)	Confidence Level	Margin of Error
L&G Focus ALF Gen1 (Form 2S)	661 000	19	80%	15%
L&G Focus ALF Gen3 (Form 2S)	476 000	11	80%	20%

Table 8. Sample size selected for each test

[2] https://www.surveymonkey.com/mp/sample-size-calculator/

5 Quantification of life profile constraints

Residential meters are deployed across Hydro One's service area. To simplify the analysis, two reference cities were selected: Sarnia/Windsor and Sudbury. This choice was based on several factors, including their different climates to represent the range of failure modes and their different population densities.

5.1 Climatic conditions in the Sarnia/Windsor area

5.1.1 Mean monthly temperature

Temperature													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Daily Average (°C)	-3,8	-2,6	2,3	8,9	15	20,5	23	22	17,9	11	5,1	-1,2	8,3
Standard Deviation	2,9	2,3	1,8	1,5	2	1,3	1,3	1,4	1,4	1,6	1,7	2,8	1
Daily Maximum (°C)	-0,3	1,1	6,7	14,1	20,4	25,8	28,1	26,9	22,9	16	8,8	2	13
Daily Minimum (°C)	-7,3	-6,3	-2	3,7	9,5	15,3	17,9	17,1	12,8	6,7	1,4	-4,3	3,7

Table 9. Canadian Climate Normals station data, 1981 to 2010

Source: Environment Canada

5.1.2 Average relative humidity

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Relative Humidity - 0600LST (%)	80,2	79,3	77,3	76,6	77,6	79,5	81,5	85,6	85,2	81,3	80,3	80,6
Average Relative Humidity - 1500LST (%)	69,6	65,9	58,9	52,6	52,4	52,7	53,6	57,3	55,7	57,1	65,1	70,9

Table 10. Canadian Climate Normals station data, 1981 to 2010

Source: Environment Canada

5.1.3 Solar radiation

The rise in temperature can be calculated with the equation below (IEC 60721-2-4).

$$\Delta T = \frac{\alpha_s * E}{h_y}$$

α_s: Absorptance

E : Solar radiation (W/m^2)

h_y : heat transfer coefficient (W/m^2*°C)

α_s = 0.7 as suggested in IEC 60721-2-4

h_y = 20 W/m^2 * °C (see Section 5.5 on how this parameter was measured)

Month	Mean daily global insolation Two-axis sun-tracking (kWh/m2)	Mean daily global insolation Horizontal (tilt=0°) (kWh/m2)	hours of sunlight per day	Average Solar Radiation (W/m2)	Delta T (°C)
January	3,36	1,66	9,3	178	6
February	4,88	2,6	10,5	248	9
March	6,03	3,66	11,9	308	11
April	7,26	4,45	13,4	332	12
May	8,45	5,51	14,6	377	13
June	9,14	6,06	15,3	395	14
July	9,07	6,25	15,0	417	15
August	7,84	5,31	14,0	379	13
September	6,32	3,97	12,5	318	11
October	5,07	2,67	11,0	243	8
November	3,15	1,47	9,8	150	5
December	2,63	1,26	9,0	140	5
Annual average	6,11	3,74	12,2	307	11

Table 11. Mean monthly temperature rise from the sun, Sarnia/Windsor

Source: Natural Resources Canada

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Hours	81,7	100,3	139,9	185,2	236,6	266,3	299,1	254,3	191,3	151,2	87,6	67,4
Days with measurable	19,2	19,4	22,6	24,4	27,6	27,4	30,1	28,3	26,3	25,4	19,6	17,4
% of possible daylight hours	28	33,9	37,9	46,2	52,2	58	64,3	58,9	50,9	44,1	29,9	24
hours of sunlight	9,33	10,5	11,9	13,4	14,6	15,33	15	14	12,5	11	9,8	9
total hours / days with measurable	4,3	5,2	6,2	7,6	8,6	9,7	9,9	9,0	7,3	6,0	4,5	3,9

Table 12. Monthly sunshine duration data

Source: Natural Resources Canada

5.2 Climatic conditions, Sudbury area

5.2.1 Mean monthly temperature

Temperature													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Daily Average (°C)	-13	-11	-5	3,8	11,1	16,5	19,1	18	13	6	-1	-8,6	4,1
Standard Deviation	3,5	2,7	2,3	2,1	2,1	1,5	1,4	1,3	1,6	1,5	2	3,3	1
Daily Maximum (°C)	-8	-5,5	0,4	9,2	17	22,2	24,8	23,4	18,1	10	2,6	-4,4	9,2
Daily Minimum (°C)	-18	-16	-10	-1,7	5,2	10,7	13,4	12,4	7,8	1,7	-4,7	-13	-1

Table 13. Canadian Climate Normals station data, 1981 to 2010

Source: Environment Canada

5.2.2 Average relative humidity

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Relative Humidity - 0600LST (%)	79,4	77,4	75	74,5	77,1	82,4	85,6	89,6	91,7	88,4	87,2	84,1
Average Relative Humidity - 1500LST (%)	71,3	64,3	56,4	49,9	48,5	52	52,6	55,1	60,8	64,7	73,1	76

Table 14. Canadian Climate Normals station data, 1981 to 2010

Source: Environment Canada

5.2.3 Solar radiation

The rise in temperature can be calculated with the equation below (IEC 60721-2-4).

$$\Delta T = \frac{\alpha_s * E}{h_y}$$

α_s: Absorptance

E: Solar radiation (W/m^2)

h_y: heat transfer coefficient (W/m^2*°C)

α_s = 0.7 as suggested in IEC 60721-2-4

h_y = 20 W/m^2 * °C as suggested in IEC 60721-2-4

Month	Mean daily global insolation Two-axis sun-tracking (kWh/m2)	Mean daily global insolation Horizontal (tilt=0°) (kWh/m2)	hours of sunlight per day	Average Solar Radiation (W/m2)	Delta T (°C)
January	3,81	1,39	9,0	154	5
February	5,49	2,36	10,3	230	8
March	7,06	3,55	11,9	298	10
April	7,74	4,59	13,6	338	12
May	8,22	5,43	15,0	362	13
June	8,73	5,96	15,8	378	13
July	8,79	5,96	15,5	385	13
August	7,39	4,9	14,3	344	12
September	5,39	3,5	12,5	280	10
October	4,08	2,19	11,0	199	7
November	2,69	1,23	9,4	131	5
December	2,89	1,07	8,6	124	4
Annual average	6,03	3,52	12,2	288	10

Table 15. Mean monthly temperature rise from the sun, Sudbury

Source: Natural Resources Canada

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Hours	86,3	118,2	161	195,6	228,4	246,9	274,7	245,2	162,1	121,4	69,8	63,5
Days with measurable	20	21	25	25,4	27,1	28	30,2	29,4	26	25,3	18,1	17,1
% of possible daylight hours	30,9	40,7	43,7	48,1	49,1	52,2	57,4	55,8	42,9	35,8	24,6	23,7
hours of sunlight	9	10,25	11,9	13,6	15	15,75	15,5	14,25	12,5	11	9,4	8,6
total hours / days with measurable	4,3	5,6	6,4	7,7	8,4	8,8	9,1	8,3	6,2	4,8	3,9	3,7

Table 16. Monthly sunshine duration data

Source: Natural Resources Canada

5.3 Average load of a residential meter

To quantify the average load of a residential customer, Hydro One provided Table 17, which details each rate category and the number of customers on each.

rate_category	avg_daily_kWh	sample_size
GSE_2TRRPP	41,749	24
GSE_DCB	41,780	2784
GSE_TOURPP	25,736	30884
R1_2TR_RPP	35,370	174
R1_DCB	26,798	7490
R1_TOU_RPP	27,046	293061
R2_2TR_RPP	35,912	278
R2_DCB	34,081	3308
R2_TOU_RPP	32,167	161052
S_2TR_RPP	24,740	41
S_DCB	12,805	515
S_TOU_RPP	11,552	97792
UGE_2TRRPP	24,019	2
UGE_DCB	46,141	379
UGE_TOURPP	30,379	3973
UR_2TR_RPP	23,572	20
UR_DCB	22,776	4670
UR_TOU_RPP	22,570	145785

Table 17. Number of customers and average consumption by rate

A weighted average was used to determine the average load of a residential customer. Each average daily kWh was multiplied by the sample size. We then summed all the power consumption and divided by the sum of sample size. This produces an average of 25.2863 kWh or 1.053 kW for 24 hours. This means that a customer with 2S meter at 240 V will draw 4.39 A. We decided to round up that value and use a 5-A load (or 1.2 kW at 240 V) for all tests.

5.4 Electronic part self-heating

Testing was performed in the Hydro-Québec climate chamber to accurately determine the circuit board temperature rise under different temperature conditions and with an average residential load (5A, see section 5.3 for details).

Seven thermocouples were installed in a Focus ALF equipped with a GEN3 communications board to measure the meter's internal temperature at different ambient temperatures (ambient temperature of the chamber is shown on the blue stepped curve in Figure 11). Of the seven thermocouples, three were on the metrology board (one each on the transformer, Teridian microcontroller and the PCB) and four on the communications board. Readings from the three thermocouples on the metrology board are shown in Figure 11 by the green (106-XFO), red (108-PCB) and blue (107-Teridian) curves. Note that this board's temperatures are appreciably higher due to transformer heat loss dissipation over the traces and through the air to all parts of the board.

The temperatures recorded by the four thermocouples on the communications board are also shown in Figure 11. The four measurement points were: the Faraday cage (light blue, 101-FaradayCage), the microcontroller (orange, 102-uC), the PCB (grey, 103-PCB) and capacitor C38 (yellow, 104-C38). Note that the average temperature of the communications board was 4 to 14°C lower than that of the metrology board.

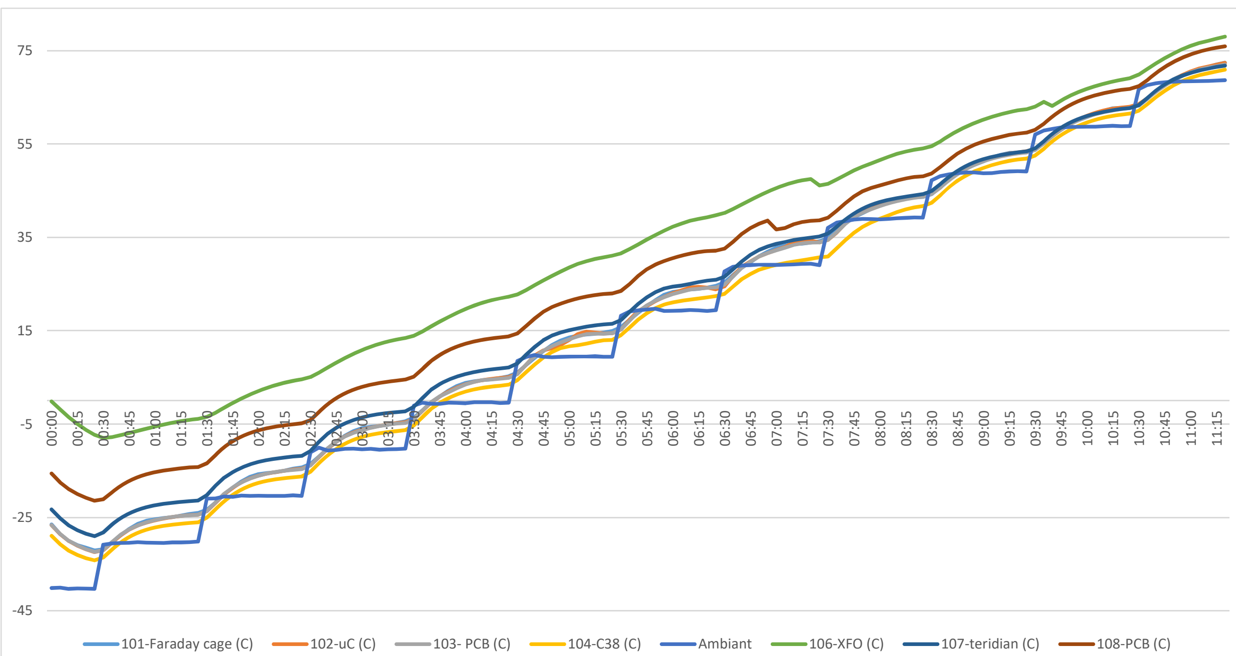


Figure 11. Temperature readings during test

Table 18 presents the average of the thermocouples for each board at the thermal equilibrium just before changing levels.

Ambiant temperature (°C)	Heat rise due to internal electronic on Communication board (°C)	Heat rise due to internal electronic on Metrology board (°C)	Heat rise on transformer (°C)
-40	7,527	15	33
-30	5,43	12,39	26,25
-20	5,466	12,074	24,972
-10	5,26	11,41	23,735
0	5,07	10,84	22,677
10	4,8	10,334	21,662
20	4,4	9,622	20,332
30	4,11	7,83	17,06
40	3,97	6,95	14,802
50	3,8	6,33	13,35
60	3,65	5,895	10,24
70	3,5	5,17	9,3

Table 18. Summary of self-heating characterization test results

Figure 12 graphs the values from Table 18 with three first-order linear trends.

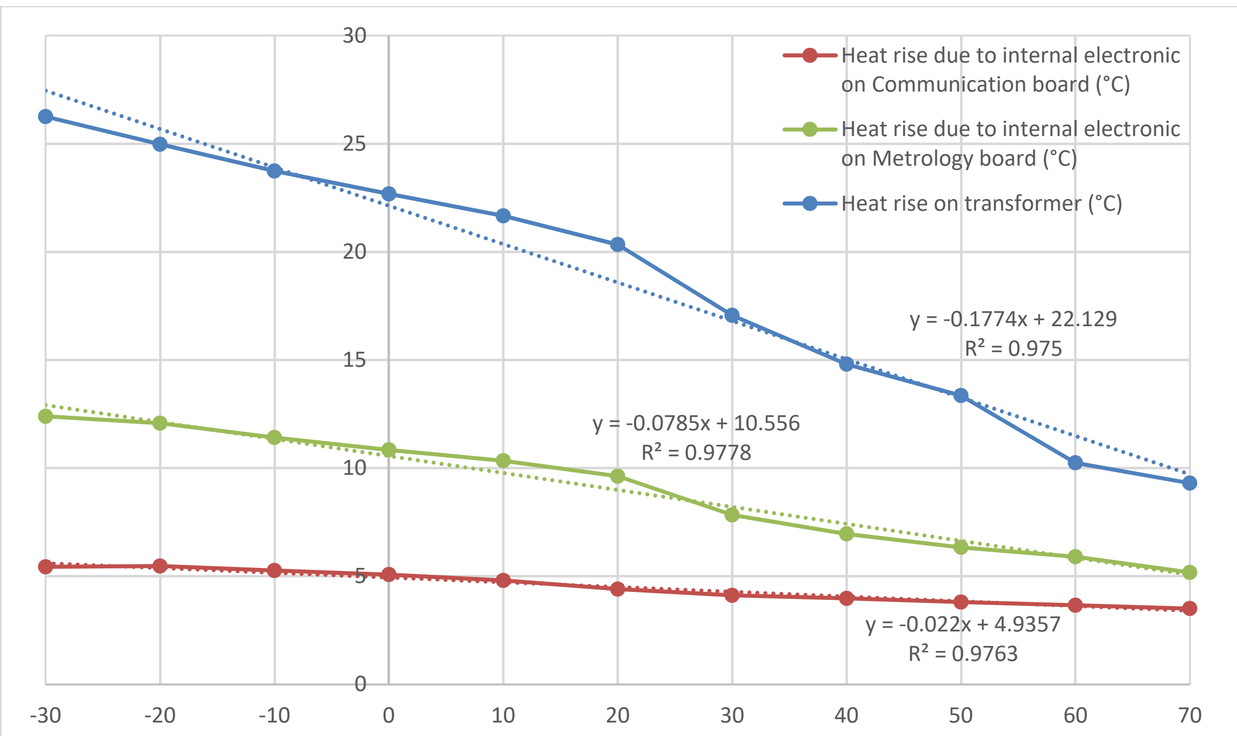


Figure 12. Summary of self-heating characterization results

The approximate relationship between transformer temperature rise and ambient temperature rise is described by the equation:

$$y = -0.1774x + 22.129$$

The approximate relationship between internal temperature rise and ambient temperature rise on the metrology board is described by the equation:

$$y = -0.0785x + 10.556$$

The approximate relationship between internal temperature rise and ambient temperature rise on the communications board is described by the equation:

$$y = -0.022x + 4.94$$

The following sections use these equations to estimate temperature rise due to electronic components.

5.5 Temperature rise in the sun

To determine the impact of sunlight on the internal temperature of the meter, outdoor testing was carried out on October 23, 2019, July 20, 2020, and August 7, 2020. Two unpowered Focus AXR-SD meters, the cases of which are externally identical to the Focus ALF meter used by Hydro One, were equipped with three temperature sensors. The meters were placed in the sun and the shade, respectively. An amorphous thin film solar panel was used to measure light intensity and charge a 12-V battery connected to the 120-V inverter that powered the test bench.

Figure 13. Solar heating test apparatus

An Agilent 34972A was used for temperature, voltage and current signal acquisition. During the tests, the temperature, voltage and current were measured once a minute.

Solar irradiance (W/m2)	Output Power (W)	Efficiency (%)
58	0,90	5,96%
64	1,00	5,96%
80	1,25	5,98%
84	1,30	5,93%
103	1,43	5,31%
143	2,04	5,47%
152	1,79	4,51%
162	2,16	5,11%
175	2,07	4,53%
185,2	2,36	4,89%
190	2,23	4,50%
198	2,57	4,97%
225	3,00	5,11%
275	3,25	4,53%
283	3,31	4,48%
283	3,33	4,50%
423	4,31	3,90%
429	5,68	5,07%
460	6,07	5,06%
818	9,8	4,59%
905	10,162	4,30%
1046	10,93	4,00%

Table 19. Measured solar panel efficiency

To convert the power produced by the solar panels into solar irradiation, the efficiency and size of the panel are required. The solar panel used (Sunforce 50120 20 W) measures 29 cm x 90 cm, for a surface area of 0.261 m^2. However, its specifications do not give its efficiency. Instead, a device to measure solar radiation was used to produce Table 19. The efficiency of a solar panel decreases as temperature increases[3]. That explains why Table 19 shows panel efficiency decreasing as solar radiation increases.

Solar radiation can be expressed as:

$$\text{Solar Radiation } \left({}^{W}/_{m^2}\right) = \frac{Power\ (W)}{Area\ \left(m^2\right) * Efficiency(\%)}$$

To simplify calculation, we assume that the panel has a set efficiency of 5%, the average between the best and worst observed efficiency values.

[3] Source :https://en.wikipedia.org/wiki/Solar_cell_efficiency

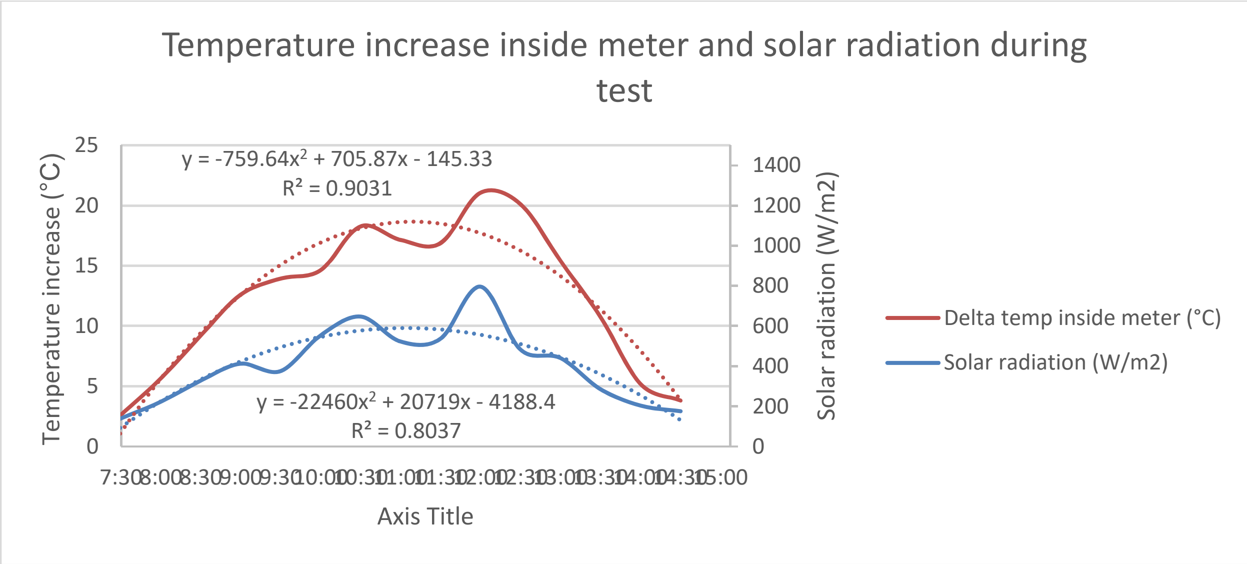


Figure 14. Temperature increase inside the meter and solar radiation during test

In Figure 14, the red curve represents the temperature increase inside the meters and the blue curve graphs the solar radiation measured at the same time. For example, around noon, the temperature increased about 23°C inside the meter. At the same time, the sun was producing about 800 W/m^2 of solar radiation.

We used the mean value theorem for integrals to find the average daily values[4]:

$$f(c) = f_{avg} = \frac{1}{b-a}\int_a^b f(x)dx$$

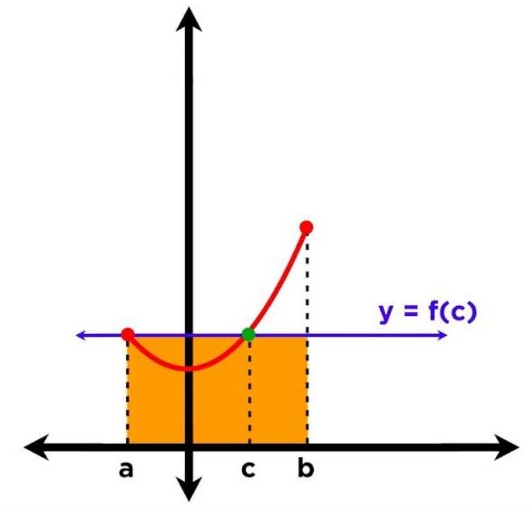


Figure 15. Graph of the mean value theorem for integrals

[4] Source : https://en.wikipedia.org/wiki/Mean_value_theorem

Using the equation above, we solved for the average solar radiation and average temperature rise:

$$f_{avg} = \frac{1}{b-a}\int_a^b f(x)dx = \frac{1}{0.6-0.3125}\int_{0.3125}^{0.6} -759.64x^2 + 705.87x - 145.33\, dx$$

$$\frac{1}{0.6-0.3125}(-253.2x^3 + 352.9x^2 - 145.33x)|_{0.3125}^{0.6} = 13.2°C$$

$$f_{avg} = \frac{1}{b-a}\int_a^b f(x)dx = \frac{1}{0.6-0.3125}\int_{0.3125}^{0.6} -22460x^2 + 20719x - 4188\, dx$$

$$\frac{1}{0.6-0.3125}(-7486x^3 + 10359x^2 - 4188x)|_{0.3125}^{0.6} = 417 W/m^2$$

Using the equation described in IEC 60721-2-4, we find the heat transfer coefficient, h_y ($W/m^2°C$):

$$h_y = \frac{\alpha_s * E}{\Delta T} = 22\ W/m^2°C$$

This measured value is very close to 20 W/m^2 °C, the value suggested by Standard IEC 60721-2-4.

The value of 20 W/m^2 was used to comply with the requirements of IEC 60721-2-4.

5.6 Failure criterion

This section sets out the parameters that determine if a meter has failed. It lists the main failure modes and recommends an analysis method for each case.

5.6.1 LCD

To determine whether an LCD remains legible, we used the parameters recommended in the LEA test[5]. By this definition, a contrast of 2.5% will be visible to people with visual acuity between 0.3 and 0.8 (20/60 to 20/25). This conservative threshold takes into account the fact that some people do not have perfect vision.

Calculating LCD contrast requires two colorimeter measurements: the colour of the screen background and the colour of a segment. A special template was created for this test to ensure that measurements were always taken of the same locations.

Figure 16. LCD colour measurement setup with template

The Weber contrast equation[6] was used to calculate the contrast and compare it to the threshold values.

$$\text{Weber Contrast} = \frac{I - I_B}{I_B}$$

[5] Source: http://www.lea-test.fi/en/vistests/occupati/cs/occ_cs.html
[6] Source: https://en.wikipedia.org/wiki/Contrast_(vision)

where I and I_b represent the luminance of the object and the immediate background, respectively.

5.6.2 Communication

All communication problems were detected using the load profiles transmitted to the data collector. When a meter stopped transmitting load profiles, it was identified as defective. This technique has the advantage of being very accurate; the one-hour resolution allows the time of last transmission to the nearest hour. It cannot, however, immediately detect a meter with an intermittent communication problem, which after several attempts will eventually successfully transmit its load profiles. This behaviour was observed when a Hydro-Québec technician failed to communicate with a meter while it was still transmitting its load profiles to the data collector.

5.6.3 Capacitors

NessCap, which manufactures the super capacitors used as C2, C7 and C21 in GEN1, has set their end-of-life criterion as a 30% of capacitance loss and an increase of ESR by a factor of 2. For this study, only capacitance was measured.

The associated capacity in farads can be calculated as[7]:

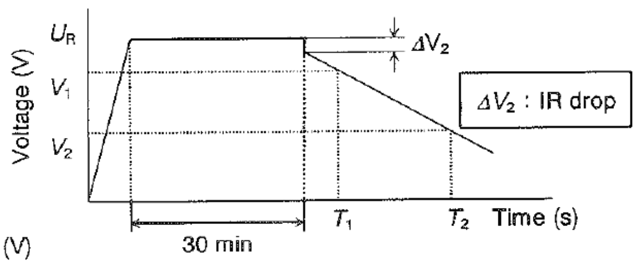
$$W = \int_0^Q V(q)dq = \int_0^Q \frac{q}{C}dq = \frac{1}{2}\frac{Q^2}{C} = \frac{1}{2}VQ = \frac{1}{2}CV^2$$

$$C = \frac{Q}{V} = \frac{I * \Delta t}{V}$$

Standard JEITA RCR-2370B, Section 6.2.1 sets out how to measure the capacitance of a capacitor (see Figure 17). This method charges an isolated capacitor (not connected to a circuit) for 30 minutes and discharges it in a controlled manner with a constant current. Laboratory testing on the capacitors in the meters showed that a satisfactory alternative method is to measure the constant current charging time of the capacitor when connected to the circuit and multiply it by a constant determined in the laboratory. This method has the advantage of being much simpler and faster to perform during testing.

[7] Source : https://en.wikipedia.org/wiki/Capacitor

$$C = \frac{I \times (T_2 - T_1)}{(V_1 - V_2)}$$



Where,
- C is capacitance (F)
- I is discharge current (A)
- V_1 is measurement starting voltage (V)
- V_2 is measurement end voltage (V)
- T_1 is time from discharge start to reach V_1 (s)
- T_2 is time from discharge start to reach V_2 (s)

Figure 17. JEITA RCR-2370B method for measuring capacitor capacitance

Each week during functional testing, the time to charge capacitor C21 was measured. The capacitor was first discharged, then with a constant charge current of 300 mA, the time to increase from 0 V to 3.3 V was recorded. This makes it possible to track the capacitor's capacitance over time.

5.6.4 J1 connector

Readings were taken weekly with Procare software to verify that the meter is communicating properly. Load profiles were also examined to detect any communication problems. Lastly, a visual inspection of the J1 connector was performed to confirm suspected broken solder joints.

6 Test selection and descriptions

In this section, using life profile elements, we calculate the duration of the main reliability tests (HTOL, thermal cycling and damp heat). We will define the parameters for each test and the associated ruggedness tests.

6.1 HTOL

6.1.1 Objectives

The high temperature operating life (HTOL) test addresses failure mechanisms accelerated by temperature that are primarily caused by the following phenomena:

- Electrical parameter drift that could lead to component malfunction.
- Physical faults:
  - Plastic aging, volatile compound deposit
  - Material dilation
  - Contact degradation
  - Material aging.

6.1.2 Acceleration model

The Arrhenius accelerated life model is used for HTOL testing. This model defines the acceleration factor as the relationship between the length of time a product is used and the duration of the test as a function of the stress temperature[8]. This basic model was used for components with no additional constraints (electrical or mechanical), such as the liquid crystal display.

$$AF = e^{\left(\frac{Ea}{k} * \left(\frac{1}{Tu} - \frac{1}{Ts}\right)\right)}$$

Where

Ea: The activation energy of the desired failure mechanism, in eV
K: Boltzmann constant = 8.61×10^{-5}
Tu: Operating temperature, in Kelvin
Ts: Tested stress temperature, in Kelvin

Test duration is defined by:

Test duration (hours) = Service life (hours) / AF

[8] https://en.wikipedia.org/wiki/Arrhenius_equation

For the calculation, we consider the case of the temperatures defined in the mission profile. The calculations below took into account:

- Arrhenius model, with an activation energy of (in accordance with the values from the FIDES guide):
  - o Transformer: 0.15 eV
  - o Al-electrolytic capacitors: 0.4 eV
  - o LCD: 0.6 eV
- Stress temperature = Ambient temperature around components during the test.
- Operating temperature = Estimated operating temperature around components:
  - ➢ Tu = T1 + T2 + T3 depending on case (insulation effective or not)
  - ➢ T1 = Ambient temperature around operating unit.
  - ➢ T2 = Temperature rise inside unit due to self-heating:
    - o For the transformer, the transformer equation was used
    - o For the LCD, the metrology board equation was used
    - o For the capacitor, the communication board equation was used
  - ➢ T3 = Temperature rise due to solar radiation.

    Meters facing south receive 100% of sunlight. Meters facing north receive 0% of sunlight. Meters facing east receive 50% of sunlight. Meters facing west receive 50% of sunlight. Thus, we estimate that only 50% of the meters are subjected to heat rise due to sunlight, hence we divide the values from Tables 11 and 15 by 2.

The stress temperature on the meters is determined as a function of their manufacturer-specified maximum operating temperature. To avoid triggering non-target failures or parameter drift, it must not be exceeded. Thus, the test temperature was set at 85°C. During testing, meters were powered and operated with a 5-A load, as specified in the parameters in Section 5.3.

Life expectancy (years)	15
Ambiant Température under stress (°C)	85
Measured Température under stress (°C)	88
Activation Energy (eV)	0,4

*Windsor temp with Sarnia sun	January			February			March			April			May			June		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	19,2	19,2		19,4	19,4		22,6	22,6		24,4	24,4		27,6	27,6		27,4	27,4	
Bright Sunshine (hrs/day)	5,1	4,3		5,3	5,2		5,7	6,2		5,8	7,6		6,0	8,6		5,6	9,7	
Daily extremum ambiant temperature (°C) - T1	-0,3	-0,3	-7,3	1,1	1,1	-6,3	6,7	6,7	-2,2	14,1	14,1	3,7	20,4	20,4	9,5	25,8	25,8	15,3
Temp rise due to Self-heating (°C) - T2	4,9	4,9	5,1	4,9	4,9	5,1	4,8	4,8	5,0	4,6	4,6	4,8	4,5	4,5	4,7	4,4	4,4	4,6
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	7	0	0	7	0
Reference Temperature - Tu	5	8	-2,2	6	10	-1	11	17	3	19	25	9	25	31	14	30	37	20
Days per month	31	19,2	31	28	19,4	28	31	22,6	31	30	24,4	30	31	27,6	31	30	27,4	30
Days per month without sun	11,8		31	8,6		28	8,4		31	5,6		30	3,4		31	2,6		30
Hours per day with Bright Sunshine	5	4		5	5		6	6		6	8		6	9		6	10	
Hours per day without Bright Sunshine	9		15	11		14	12		12	13		11	15		9	15		9
Total duration with bright sunshine (h)	1462	1226	0	1551	1505	0	1936	2099	0	2126	2778	0	2495	3549	0	2306	3995	0
Total duration without bright sunshine (h)	1651	0	6822	1355	0	5670	1499	0	5627	1126	0	4770	745	0	4371	598	0	3902
AF Acceleration Factor	48	40	73	44	34	68	32	24	53	21	16	38	15	11	27	12	8	20
Test Duration with bright sunshine (h)	31	31	0	35	44	0	61	89	0	100	178	0	163	326	0	198	483	0
Test Duration without bright sunshine (h)	35	0	94	31	0	83	47	0	105	53	0	126	49	0	160	51	0	196

*Windsor temp with Sarnia sun	July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	30,1	30,1		28,3	28,3		26,3	26,3		25,4	25,4		19,6	19,6		17,4	17,4	
Bright Sunshine (hrs/day)	5,1	9,9		5,0	9,0		5,2	7,3		5,0	6,0		5,3	4,5		5,1	3,9	
Daily extremum ambiant temperature (°C) - T1	28,1	28,1	17,9	26,9	26,9	17,1	22,9	22,9	12,8	15,8	15,8	6,7	8,8	8,8	1,4	2	2	-4,3
Temp rise due to Self-heating (°C) - T2	4,3	4,3	4,5	4,3	4,3	4,6	4,4	4,4	4,6	4,6	4,6	4,8	4,7	4,7	4,9	4,9	4,9	5,0
Temp rise due to sun (°C) - T3	0	7	0	0	7	0	0	6	0	0	4	0	0	3	0	0	2	0
Reference Temperature - Tu	32	40	22	31	37,9	22	27	33	17	20	25	11	14	16	6	7	9	1
Days per month	31	30,1	31	31	28,3	31	30	26,3	30	31	25,4	31	30	19,6	30	31	17,4	31
Days per month without sun	0,9		31	2,7		31	3,7		30	5,6		31	10,4		30	13,6		31
Hours per day with Bright Sunshine	5	10		5	9		5	7		5	6		5	4		5	4	
Hours per day without Bright Sunshine	15		9	14		10	13		12	11		13	10		14	9		15
Total duration with bright sunshine (h)	2286	4487	0	2129	3815	0	2062	2870	0	1923	2268	0	1567	1314	0	1338	1011	0
Total duration without bright sunshine (h)	203	0	4185	567	0	4650	694	0	5175	924	0	6045	1529	0	6390	1836	0	6975
AF Acceleration Factor	10	7	17	11	8	18	13	10	23	19	15	32	28	24	43	42	36	61
Test Duration with bright sunshine (h)	220	615	0	193	479	0	153	282	0	99	146	0	55	54	0	32	28	0
Test Duration without bright sunshine (h)	19	0	241	51	0	256	52	0	227	48	0	190	54	0	148	44	0	115

Average Acceleration factor	20
Total duration of test to cover 15 years (h)	6571
Duration of test at CRIQ (h)	2400

Table 20. Windsor ALT data for capacitor in HTOL

*Sudbury	January			February			March			April			May			June		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	20	20		21	21		25	25		25,4	25		27,1	27		28	28	
Bright Sunshine (hrs/day)	4,7	4,3		4,6	5,6		5,5	6,4		5,9	7,7		6,6	8,4		6,9	8,8	
Daily extremum ambiant temperature (°C) - T1	-8	-8	-17,9	-5,5	-5,5	-16	0,4	0,4	-10,2	9,2	9,2	-1,7	17	17	5,2	22,2	22,2	10,7
Temp rise due to Self-heating (°C) - T2	5,1	5,1	5,3	5,1	5,1	5,3	4,9	4,9	5,2	4,7	4,7	5,0	4,6	4,6	4,8	4,4	4,4	4,7
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	6	0	0	7	0
Reference Temperature - Tu	-3	0	-12,6	0	4	-11	5	11	-5	14	20	3	22	28	10	27	33	15
Days per month	31	20	31	28	21	28	31	25	31	30	25,4	30	31	27,1	31	30	28	30
Days per month without sun	11		31	7		28	6		31	4,6		30	3,9		31	2		30
Hours per day with Bright Sunshine	5	4		5	6		5	6		6	8		7	8		7	9	
Hours per day without Bright Sunshine	9		15	10		14	12		12	14		10	15		9	16		8
Total duration with bright sunshine (h)	1406	1295	0	1456	1773	0	2048	2415	0	2248	2934	0	2672	3426	0	2912	3704	0
Total duration without bright sunshine (h)	1485	0	6975	1076	0	5775	1071	0	5627	938	0	4680	878	0	4185	473	0	3713
AF Acceleration Factor	76	64	144	65	51	127	46	34	87	28	20	52	18	13	35	14	10	26
Test Duration with bright sunshine (h)	18	20	0	22	35	0	45	72	0	81	147	0	147	262	0	209	371	0
Test Duration without bright sunshine (h)	20	0	48	17	0	45	23	0	64	34	0	90	48	0	121	34	0	145

*Sudbury	July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	30,2	30		29,4	29		26	26		25,3	25		18,1	18		17,1	17	
Bright Sunshine (hrs/day)	6,4	9,1		5,9	8,3		6,3	6,2		6,2	4,8		5,5	3,9		4,9	3,7	
Daily extremum ambiant temperature (°C) - T1	24,8	24,8	13,4	23,4	23,4	12,4	18,1	18,1	7,8	10,3	10,3	1,7	2,6	2,6	-4,7	-4,4	-4,4	-12,7
Temp rise due to Self-heating (°C) - T2	4,4	4,4	4,6	4,4	4,4	4,7	4,5	4,5	4,8	4,7	4,7	4,9	4,9	4,9	5,0	5,0	5,0	5,2
Temp rise due to sun (°C) - T3	0	7	0	0	6	0	0	5	0	0	3	0	0	2	0	0	2	0
Reference Temperature - Tu	29	36	18	28	33,8	17	23	28	13	15	18	7	7	10	0	1	3	-7
Days per month	31	30,2	31	31	29,4	31	30	26	30	31	25,3	31	30	18,1	30	31	17,1	31
Days per month without sun	0,8		31	1,6		31	4		30	5,7		31	11,9		30	13,9		31
Hours per day with Bright Sunshine	6	9		6	8		6	6		6	5		6	4		5	4	
Hours per day without Bright Sunshine	16		9	14		10	13		12	11		13	9		15	9		15
Total duration with bright sunshine (h)	2901	4121	0	2606	3678	0	2444	2432	0	2354	1821	0	1505	1047	0	1253	952,5	0
Total duration without bright sunshine (h)	186	0	3953	342	0	4534	750	0	5175	941	0	6045	1678	0	6570	1793	0	7161
AF Acceleration Factor	12	9	22	13	10	23	17	13	30	26	22	42	40	35	62	61	53	102
Test Duration with bright sunshine (h)	237	471	0	199	379	0	142	183	0	90	85	0	37	30	0	21	18	0
Test Duration without bright sunshine (h)	15	0	179	26	0	195	44	0	173	36	0	143	42	0	106	29	0	70

Average Acceleration factor	26
Total duration of test to cover 15 years (h)	5067
Duration of test at CRIQ (h)	2400

Table 21. Sudbury ALT data for capacitor in HTOL

Durée D'utilisation (année)	15
Température de stress (°C)	85
Température réel en stress (°C)	92
Énergie Activation	0,15

*Windsor temp with Sarnia sun	January			February			March			April			May			June			July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	19,2	19,2		19,4	19,4		22,6	22,6		24,4	24,4		27,6	27,6		27,4	27,4		30,1	30,1		28,3	28,3		26,3	26,3		25,4	25,4		19,6	19,6		17,4	17,4	
Bright Sunshine (hrs/day)	5	4		5	5		6	6		6	8		6	9		6	10		5	10		5	9		5	7		5	6		5	4		5	4	
Daily extremum ambiant temperature (°C) - T1	-0,3	-0,3	-7,3	1,1	1,1	-6,3	6,7	6,7	-2,2	14,1	14,1	3,7	20,4	20,4	9,5	25,8	25,8	15,3	28,1	28,1	17,9	26,9	26,9	17,1	22,9	22,9	12,8	15,8	15,8	6,7	8,8	8,8	1,4	2	2	-4,3
Temp rise due to Self-heating (°C) - T2	22,2	22,2	23,4	21,9	21,9	23,2	20,9	20,9	22,5	19,6	19,6	21,5	18,5	18,5	20,4	17,6	17,6	19,4	17,1	17,1	19,0	17,4	17,4	19,1	18,1	18,1	19,9	19,3	19,3	20,9	20,6	20,6	21,9	21,8	21,8	22,9
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	7	0	0	7	0	0	7	0	0	7	0	0	6	0	0	4	0	0	3	0	0	2	0
Reference Temperature - Tu	22	25	16,1	23	27	17	28	33	20	34	40	25	39	46	30	43	50	35	45	53	37	44	50,9	36	41	47	33	35	39	28	29	32	23	24	26	19
Days per month	31	19,2	31	28	19,4	28	31	22,6	31	30	24,4	30	31	27,6	31	30	27,4	30	31	30,1	31	31	28,3	31	30	26,3	30	31	25,4	31	30	19,6	30	31	17,4	31
Days per month without sun	11,8		31	8,6		28	8,4		31	5,6		30	3,4		31	2,6		30	0,9		31	2,7		31	3,7		30	5,6		31	10,4		30	13,6		31
Hours per day with Bright Sunshine	5	4		5	5		6	6		6	8		6	9		6	10		5	10		5	9		5	7		5	6		5	4		5	4	
Hours per day without Bright Sunshine	9		15	11		14	12		12	13		11	15		9	15		9	15		9	14		10	13		12	11		13	10		14	9		15
Total duration with bright sunshine (h)	1462	1226	0	1551	1505	0	1936	2099	0	2126	2778	0	2495	3549	0	2306	3995	0	2286	4487	0	2129	3815	0	2062	2870	0	1923	2268	0	1567	1314	0	1338	1011	0
Total duration without bright sunshine (h)	1651	0	6822	1355	0	5670	1499	0	5627	1126	0	4770	745	0	4371	598	0	3902	203	0	4185	567	0	4650	694	0	5175	924	0	6045	1529	0	6390	1836	0	6975
AF Acceleration Factor	3	3	3	3	3	3	3	3	3	2	2	3	2	2	3	2	2	2	2	2	2	2	1,8	2	2	2	3	2	2	3	3	3	3	3	3	3
Test Duration with bright sunshine (h)	470	419	0	510	539	0	697	836	0	859	1247	0	1107	1768	0	1107	2157	0	1134	2515	0	1038	2081	0	949	1455	0	797	1015	0	583	514	0	447	354	0
Test Duration without bright sunshine (h)	531	0	1949	446	0	1648	540	0	1753	455	0	1637	330	0	1644	287	0	1604	100	0	1790	276	0	1965	319	0	2049	383	0	2176	569	0	2112	613	0	2097

Average Acceleration factor	2,5
Total duration of test to cover 15 years (h)	51870
Duration of test at CRIQ (h)	2400

Table 22. Windsor ALT data for transformer in HTOL

*Sudbury	January			February			March			April			May			June			July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	20	20		21	21		25	25		25,4	25		27,1	27		28	28		30,2	30		29,4	29		26	26		25,3	25		18,1	18		17,1	17	
Bright Sunshine (hrs/day)	4,7	4,3		4,6	5,6		5,5	6,4		5,9	7,7		6,6	8,4		6,9	8,8		6,4	9,1		5,9	8,3		6,3	6,2		6,2	4,8		5,5	3,9		4,9	3,7	
Daily extremum ambiant temperature (°C) - T1	-8	-8	-17,9	-5,5	-5,5	-16	0,4	0,4	-10,2	9,2	9,2	-1,7	17	17	5,2	22,2	22,2	10,7	24,8	24,8	13,4	23,4	23,4	12,4	18,1	18,1	7,8	10,3	10,3	1,7	2,6	2,6	-4,7	-4,4	-4,4	-12,7
Temp rise due to Self-heating (°C) - T2	23,5	23,5	25,3	23,1	23,1	25,0	22,1	22,1	23,9	20,5	20,5	22,4	19,1	19,1	21,2	18,2	18,2	20,2	17,7	17,7	19,8	18,0	18,0	19,9	18,9	18,9	20,7	20,3	20,3	21,8	21,7	21,7	23,0	22,9	22,9	24,4
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	6	0	0	7	0	0	7	0	0	6	0	0	5	0	0	3	0	0	2	0	0	2	0
Reference Temperature - Tu	16	18	7,4	18	22	9	22	28	14	30	36	21	36	42	26	40	47	31	43	49	33	41	47,4	32	37	42	29	31	34	24	24	27	18	19	21	12
Days per month	31	20	31	28	21	28	31	25	31	30	25,4	30	31	27,1	31	30	28	30	31	30,2	31	31	29,4	31	30	26	30	31	25,3	31	30	18,1	30	31	17,1	31
Days per month without sun	11		31	7		28	6		31	4,6		30	3,9		31	2		30	0,8		31	1,6		31	4		30	5,7		31	11,9		30	13,9		31
Hours per day with Bright Sunshine	5	4		5	6		5	6		6	8		7	8		7	9		6	9		6	8		6	6		6	5		6	4		5	4	
Hours per day without Bright Sunshine	9		15	10		14	12		12	14		10	15		9	16		8	16		9	14		10	13		12	11		13	9		15	9		15
Total duration with bright sunshine (h)	1406	1295	0	1456	1773	0	2048	2415	0	2248	2934	0	2672	3426	0	2912	3704	0	2901	4121	0	2606	3678	0	2444	2432	0	2354	1821	0	1505	1047	0	1253	952,5	0
Total duration without bright sunshine (h)	1485	0	6975	1076	0	5775	1071	0	5627	938	0	4680	878	0	4185	473	0	3713	186	0	3953	342	0	4534	750	0	5175	941	0	6045	1678	0	6570	1793	0	7161
AF Acceleration Factor	4	3	4	3	3	4	3	3	4	3	2	3	2	2	3	2	2	3	2	2	3	2	1,9	3	2	2	3	3	2	3	3	3	3	3	3	4
Test Duration with bright sunshine (h)	397	387	0	429	567	0	666	870	0	842	1226	0	1127	1619	0	1327	1893	0	1373	2188	0	1208	1892	0	1048	1138	0	896	740	0	507	369	0	376	299	0
Test Duration without bright sunshine (h)	419	0	1653	317	0	1416	348	0	1529	351	0	1470	370	0	1471	215	0	1423	88	0	1579	159	0	1784	322	0	1895	358	0	2008	566	0	1962	538	0	1863

Average Acceleration factor	2,8
Total duration of test to cover 15 years (h)	47489
Duration of test at CRIQ (h)	2400

Table 23. Sudbury ALT data for transformer in HTOL

Durée D'utilisation (année)	15
Température de stress (°C)	85
Température réel en stress (°C)	89
Énergie Activation	0,6

*Windsor temp with Sarnia sun	January			February			March			April			May			June			July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	19,2	19,2		19,4	19,4		22,6	22,6		24,4	24,4		27,6	27,6		27,4	27,4		30,1	30,1		28,3	28,3		26,3	26,3		25,4	25,4		19,6	19,6		17,4	17,4	
Bright Sunshine (hrs/day)	5	4		5	5		6	6		6	8		6	9		6	10		5	10		5	9		5	7		5	6		5	4		5	4	
Daily extremum ambiant temperature (°C) - T1	-0,3	-0,3	-7,3	1,1	1,1	-6,3	6,7	6,7	-2,2	14,1	14,1	3,7	20,4	20,4	9,5	25,8	25,8	15,3	28,1	28,1	17,9	26,9	26,9	17,1	22,9	22,9	12,8	15,8	15,8	6,7	8,8	8,8	1,4	2	2	-4,3
Temp rise due to Self-heating (°C) - T2	10,6	10,6	11,1	10,5	10,5	11,1	10,0	10,0	10,7	9,4	9,4	10,3	9,0	9,0	9,8	8,5	8,5	9,4	8,4	8,4	9,2	8,4	8,4	9,2	8,8	8,8	9,6	9,3	9,3	10,0	9,9	9,9	10,4	10,4	10,4	10,9
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	7	0	0	7	0	0	7	0	0	7	0	0	6	0	0	4	0	0	3	0	0	2	0
Reference Temperature - Tu	10	13	4	12	16	5	17	22	9	24	29	14	29	36	19	34	41	25	36	44	27	35	42	26	32	37	22	25	29	17	19	21	12	12	15	7
Days per month	31	19,2	31	28	19,4	28	31	22,6	31	30	24,4	30	31	27,6	31	30	27,4	30	31	30,1	31	31	28,3	31	30	26,3	30	31	25,4	31	30	19,6	30	31	17,4	31
Days per month without sun	11,8		31	8,6		28	8,4		31	5,6		30	3,4		31	2,6		30	0,9		31	2,7		31	3,7		30	5,6		31	10,4		30	13,6		31
Hours per day with Bright Sunshine	5	4		5	5		6	6		6	8		6	9		6	10		5	10		5	9		5	7		5	6		5	4		5	4	
Hours per day without Bright Sunshine	9		15	11		14	12		12	13		11	15		9	15		9	15		9	14		10	13		12	11		13	10		14	9		15
Total duration with bright sunshine (h)	1462	1226	0	1551	1505	0	1936	2099	0	2126	2778	0	2495	3549	0	2306	3995	0	2286	4487	0	2129	3815	0	2062	2870	0	1923	2268	0	1567	1314	0	1338	1011	0
Total duration without bright sunshine (h)	1651	0	6822	1355	0	5670	1499	0	5627	1126	0	4770	745	0	4371	598	0	3902	203	0	4185	567	0	4650	694	0	5175	924	0	6045	1529	0	6390	1836	0	6975
AF Acceleration Factor	210	161	373	188	130	343	122	79	245	70	45	153	45	27	98	31	19	64	26	16	53	28	18	56	37	25	77	62	45	122	104	84	184	175	142	291
Test Duration with bright sunshine (h)	7	8	0	8	12	0	16	27	0	30	62	0	56	130	0	75	214	0	87	287	0	75	216	0	55	115	0	31	51	0	15	16	0	8	7	0
Test Duration without bright sunshine (h)	8	0	18	7	0	17	12	0	23	16	0	31	17	0	44	19	0	61	8	0	79	20	0	83	19	0	67	15	0	50	15	0	35	10	0	24

Average Acceleration factor	57
Total duration of test to cover 15 years (h)	2304
Duration of test at CRIQ (h)	2400

Table 24. Windsor ALT data for LCD in HTOL

*Sudbury	January			February			March			April			May			June			July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	20	20		21	21		25	25		25,4	25		27,1	27		28	28		30,2	30		29,4	29		26	26		25,3	25		18,1	18		17,1	17	
Bright Sunshine (hrs/day)	4,7	4,3		4,6	5,6		5,5	6,4		5,9	7,7		6,6	8,4		6,9	8,8		6,4	9,1		5,9	8,3		6,3	6,2		6,2	4,8		5,5	3,9		4,9	3,7	
Daily extremum ambiant temperature (°C) - T1	-8	-8	-17,9	-5,5	-5,5	-16	0,4	0,4	-10,2	9,2	9,2	-1,7	17	17	5,2	22,2	22,2	10,7	24,8	24,8	13,4	23,4	23,4	12,4	18,1	18,1	7,8	10,3	10,3	1,7	2,6	2,6	-4,7	-4,4	-4,4	-12,7
Temp rise due to Self-heating (°C) - T2	11,2	11,2	12,0	11,0	11,0	11,8	10,5	10,5	11,4	9,8	9,8	10,7	9,2	9,2	10,1	8,8	8,8	9,7	8,6	8,6	9,5	8,7	8,7	9,6	9,1	9,1	9,9	9,7	9,7	10,4	10,4	10,4	10,9	10,9	10,9	11,6
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	6	0	0	7	0	0	7	0	0	6	0	0	5	0	0	3	0	0	2	0	0	2	0
Reference Temperature - Tu	3	6	-6	5	10	-4	11	16	1	19	25	9	26	33	15	31	38	20	33	40	23	32	38	22	27	32	18	20	24	12	13	15	6	7	9	-1
Days per month	31	20	31	28	21	28	31	25	31	30	25,4	30	31	27,1	31	30	28	30	31	30,2	31	31	29,4	31	30	26	30	31	25,3	31	30	18,1	30	31	17,1	31
Days per month without sun	11		31	7		28	6		31	4,6		30	3,9		31	2		30	0,8		31	1,6		31	4		30	5,7		31	11,9		30	13,9		31
Hours per day with Bright Sunshine	5	4		5	6		5	6		6	8		7	8		7	9		6	9		6	8		6	6		6	5		6	4		5	4	
Hours per day without Bright Sunshine	9		15	10		14	12		12	14		10	15		9	16		8	16		9	14		10	13		12	11		13	9		15	9		15
Total duration with bright sunshine (h)	1406	1295	0	1456	1773	0	2048	2415	0	2248	2934	0	2672	3426	0	2912	3704	0	2901	4121	0	2606	3678	0	2444	2432	0	2354	1821	0	1505	1047	0	1253	952,5	0
Total duration without bright sunshine (h)	1485	0	6975	1076	0	5775	1071	0	5627	938	0	4680	878	0	4185	473	0	3713	186	0	3953	342	0	4534	750	0	5175	941	0	6045	1678	0	6570	1793	0	7161
AF Acceleration Factor	396	310	938	321	225	791	199	128	477	101	63	236	57	35	137	39	24	90	33	20	74	36	23	79	52	36	112	93	70	180	167	138	301	294	242	592
Test Duration with bright sunshine (h)	4	4	0	5	8	0	10	19	0	22	47	0	47	98	0	74	154	0	88	204	0	72	158	0	47	67	0	25	26	0	9	8	0	4	4	0
Test Duration without bright sunshine (h)	4	0	7	3	0	7	5	0	12	9	0	20	15	0	31	12	0	41	6	0	54	9	0	57	14	0	46	10	0	34	10	0	22	6	0	12

Average Acceleration factor	80
Total duration of test to cover 15 years (h)	1651
Duration of test at CRIQ (h)	2400

Table 25. Sudbury ALT data for LCD in HTOL

Note the low acceleration factor in Tables 22 and 23 of 2.5 and 2.8 respectively. It would take about 50,000 hours to reproduce a 15-year service life. This is due to the very low activation energy (Ea) of 0.15 eV. This value, recommended by the FIDES guide, shows that compared to other components, temperature rise in a transformer has very minimal impact on its service life. However, this value does not take into account manufacturing defects that could make a batch more temperature-sensitive. Unfortunately, given these results, the service life of this component cannot be predicted.

6.2 Temperature cycling

6.2.1 Objectives

This constraint is associated with temperature cycling of the product when it is in operating and sleep modes. It takes into account temperature variations related to its operation (on/off in particular) and to its environment (e.g., day/night).

The main target failure mechanisms in this thermal fatigue test are:

- Solder joint aging (cracks)
- Interconnection degradation
- Copper degradation
- Material dilation
- Creep.

The Norris-Landzberg model is used to model the acceleration of the fatigue mechanism caused by thermal variations. Derived from the Coffin-Manson model typically used for thermomechanical fatigue, it takes into account the fact that the slower the thermal cycle, the more damage it causes, such as by promoting creep in the case of solder joints. The Norris-Landzberg model itself was modified in the FIDES guide to convert the model's usual prediction of a number of cycles into an acceleration factor that can be applied to a failure rate.

6.2.2 Acceleration model

We used the FIDES version of the Norris/Landzberg model to determine testing duration.

$$AF = e^{\left(\frac{Ea}{k}\right)*\left[\frac{1}{Tu\_max}-\frac{1}{Ts\_max}\right]} * \left(\frac{DTs}{DTu}\right)^{p} * \left(\frac{Fu}{Fs}\right)^{q} \qquad (1)$$

AF:	Acceleration factor (number of use cycles/number of test cycles)
Ea:	The activation energy of the desired failure mechanism
Tu_max:	Maximum temperature in use (K)
Ts_max:	Maximum temperature in testing (K)
DTs:	Temperature differential in testing
DTu:	Temperature differential in use
Fu:	Frequency of use
Fs:	Frequency of stress
K:	Boltzmann constant
P = 1.9:	Coefficient of fatigue
q = 1/3:	Duration acceleration factor

The activation energy for these mechanisms was determined to be 0.122 eV (Source: FIDES guide).

6.2.3 Calculations

The calculations use the life profile assumptions for the product.

They used an 80-minute thermal stress cycle of temperatures between -40 and +85°C (product specification), for a thermal amplitude of 125°C and a frequency of 18 cycles per day.

The values used in the tables below were based on real-world conditions. For example, the mean maximum temperature of the solder joints was measured by thermocouple during testing to be 81°C.

Life duration (years)	15
Maximum stress temperature (°C)	81
Temperature amplitude of the cycle (°C)	118
Number of cycles per day in real life	1
Number of cycles per day in ALT	18
Activation Energy (eV)	0,122

*Windsor temp with Sarnia sun	January		February		March		April		May		June		July		August		September		October		November		December	
	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun
Days with measurable sunshine	12	19	9	19	8	23	6	24	3	28	3	27	1	30	3	28	4	26	6	25	10	20	14	17
Average Max Temp. (°C)	5	17	6	23	11	33	19	42	25	51	30	58	32	62	31	58	27	50	20	37	14	24	7	17
Total cycles	180	285	135	285	120	345	90	360	51	414	39	411	13,5	451,5	40,5	424,5	55,5	394,5	84	381	156	294	204	261
Temp Delta (°C)	7	19	7	25	9	30	10	33	11	37	10	38	10	39	10	36	10	32	9	26	7	18	6	16
Acceleration Factor	257	36	231	23	163	15	121	13	111	10	119	10	126	9	135	11	128	14	156	20	231	42	314	51
Number of cycles in test	0,7	8,0	0,6	12,6	0,7	22,6	0,7	28,5	0,5	40,0	0,3	41,4	0,1	48,3	0,3	39,0	0,4	29,0	0,5	18,6	0,7	7,0	0,7	5,1

Average Acceleration Factor	13,4
Cycles required to cover life duration (cycles)	306

Table 26. Windsor ALT data for solder in change of temperature

*Sudbury	January		February		March		April		May		June		July		August		September		October		November		December	
	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun	d/n	sun
Days with measurable sunshine	11	20	7	21	6	25	5	25	4	27	2	28	1	30	2	29	4	26	6	25	12	18	14	17
Average Max Temp. (°C)	-3	8	0	16	5	26	14	38	22	47	27	53	29	56	28	52	23	42	15	29	7	17	1	9
Total cycles	165	300	105	315	90	375	75	375	59	407	30	420	12	453	24	441	60	390	86	380	179	272	209	257
Temp Delta (°C)	10	20	10	26	10	31	11	34	12	37	11	38	11	38	11	35	10	30	8	22	7	16	8	17
Acceleration Factor	133	32	119	20	117	14	111	12	95	10	100	10	102	10	109	12	123	16	174	27	237	49	186	46
Number of cycles in test	1,2	9,4	0,9	15,9	0,8	26,2	0,7	31,2	0,6	38,8	0,3	41,9	0,1	46,0	0,2	37,8	0,5	24,7	0,5	14,0	0,8	5,5	1,1	5,5

Average Acceleration Factor	13,5
Cycles required to cover life duration (cycles)	305

Table 27. Sudbury ALT data for solder in change of temperature

The number of -40/+85°C cycles to simulate a 15-year solder life cycle was determined to be 305 or 306, depending on geographic location. This is in contrast to the 700 cycles discussed at the outset of the project and based on previous Hydro-Québec testing, which had shown that 700 cycles were needed to simulate a 15-year service life on another type of equipment with a different activation energy. Cycle duration, however, was left unchanged at 80 minutes, with a 12-minute rise and a 14-minute fall (limitations of the environmental chamber). Thus, steps of 27 minutes were used. Figure 18 illustrates the temperatures used in the tests.

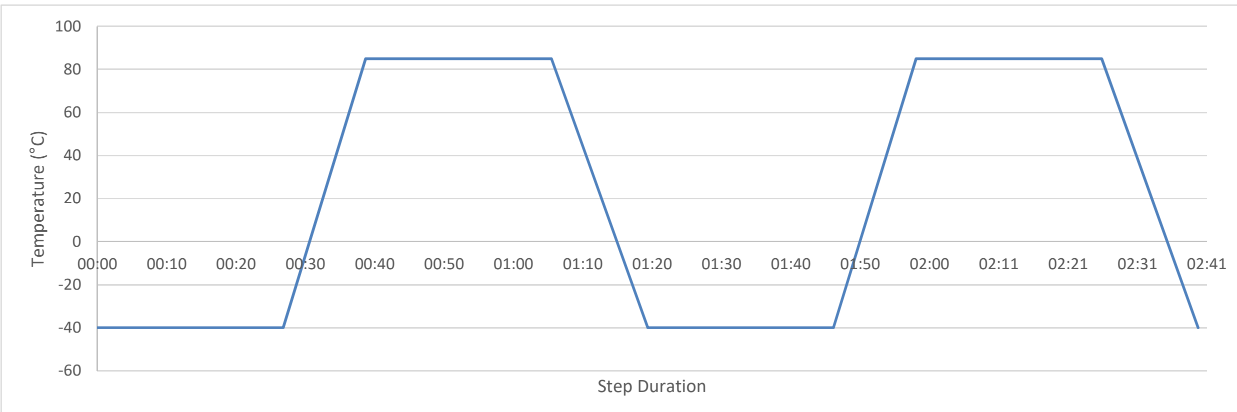


Figure 18. Temperature curve for thermal cycling

In order to achieve thermal equilibrium more quickly, the transparent polycarbonate cover was removed for this test. Laboratory testing showed that with the polycarbonate cover in place, it could take nearly an hour to reach thermal equilibrium, while with the cover removed, equilibrium was reached in 30 minutes (including the rise time).

Thermocouples were installed in the meters to verify the temperatures the components were exposed to during the test.

During testing, the meters were powered and operated with a 5-A load, as specified in the parameters in Section 5.3.

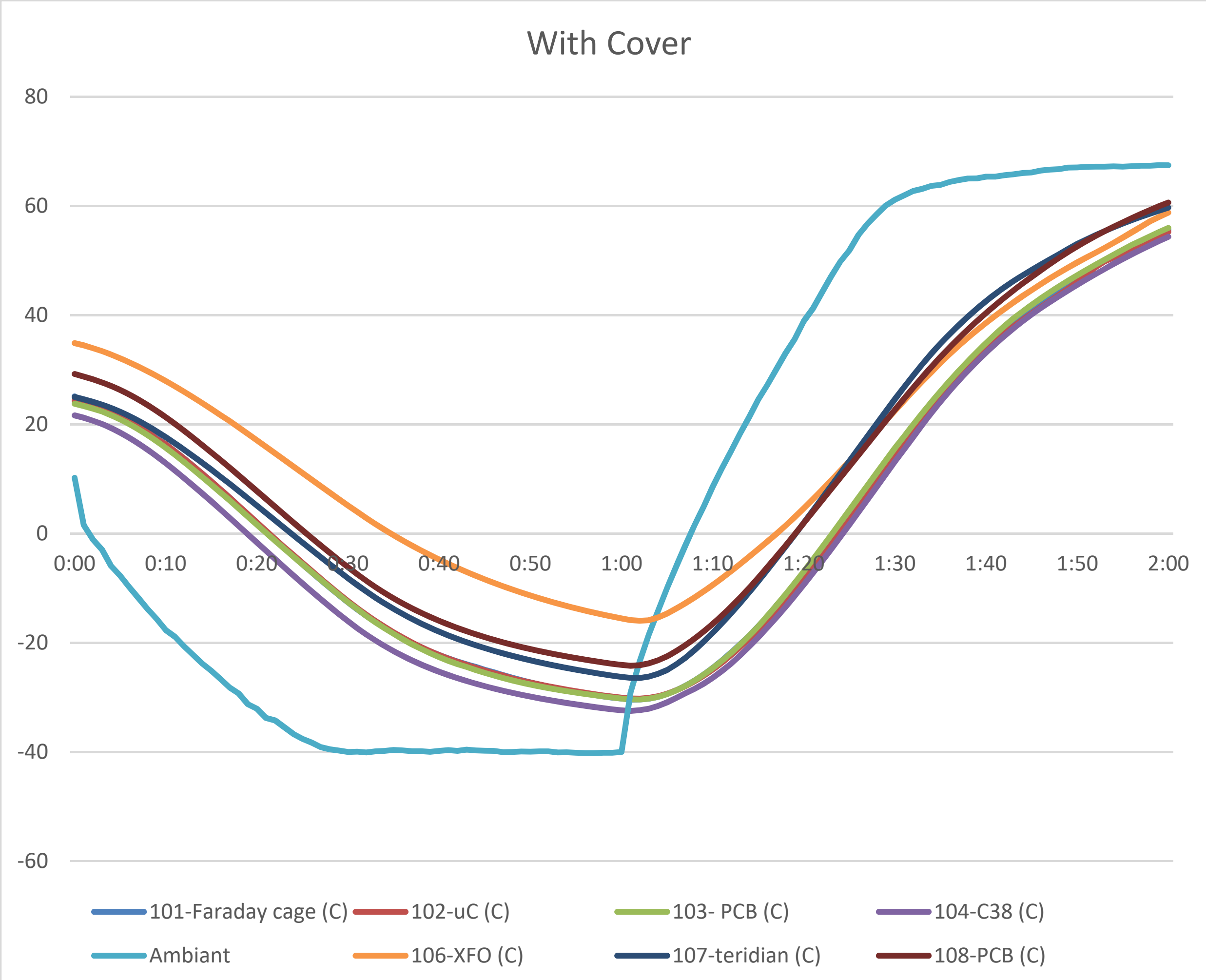


Figure 19. Internal temperature with polycarbonate cover

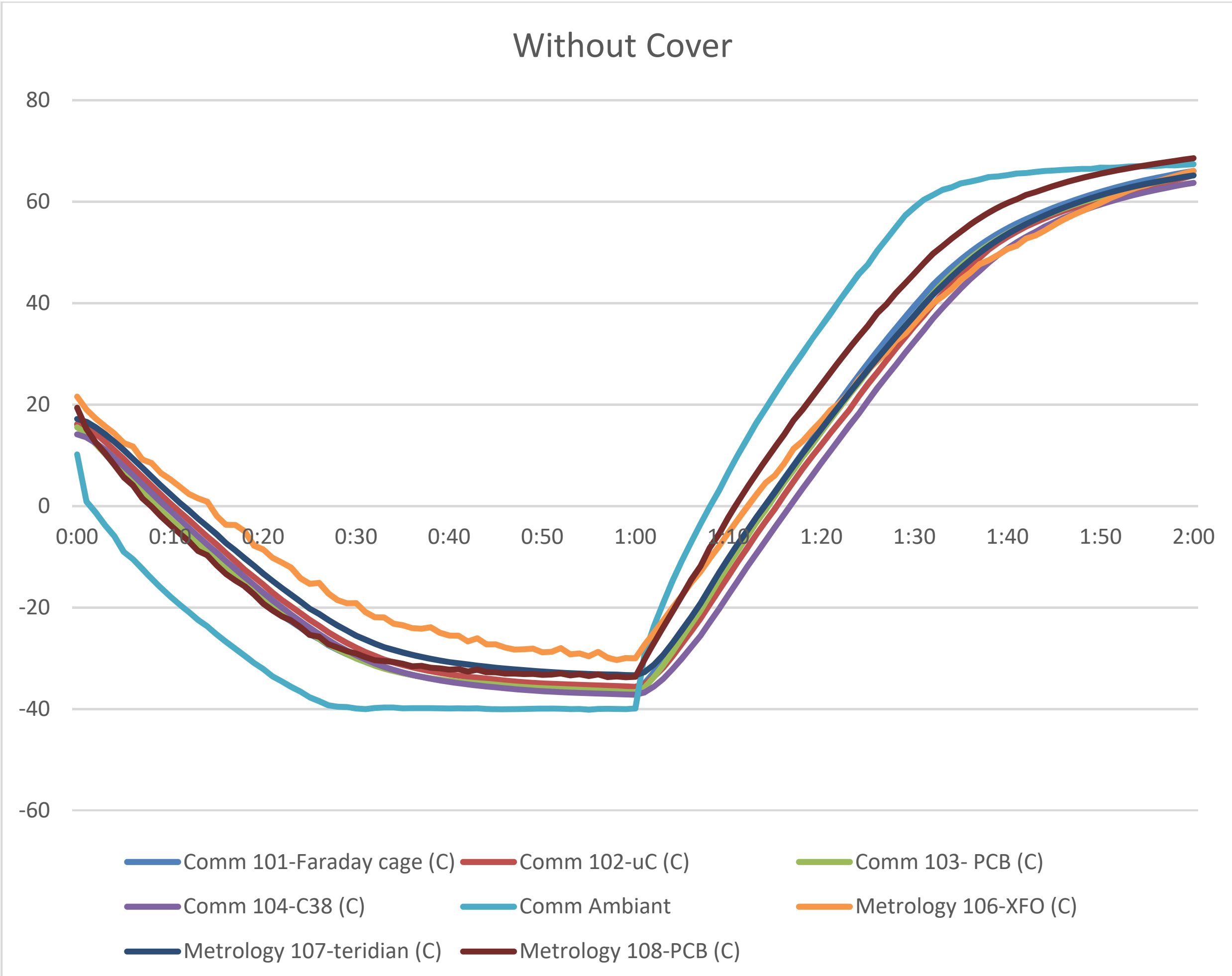


Figure 20. Internal temperature without polycarbonate cover

6.3 Temperature and humidity

6.3.1 Objectives

The main failure mechanisms targeted by this damp heat test are material degradation by corrosion and migration phenomena that could cause electrical leakage or short-circuits.

6.3.2 Acceleration model

The Peck/Bell accelerated life model was used for the damp heat testing:

$$AF = e^{\left(\left(\frac{Ea}{k}\right)*\left(\frac{1}{Tu}-\frac{1}{Ts}\right)\right)} * \left(\frac{RHu}{RHs}\right)^{-2.66}$$

Where:

Ea:	The activation energy of the desired failure mechanism, in eV
K:	Boltzmann constant = 8.6x10-5
Tu:	Mean maximum temperature in use (K)
Ts:	Stress temperature of the test (K)
RHu:	Mean maximum humidity in use
RHs:	Stress relative humidity of the test

With:

AF = Use duration / Test duration

6.3.3 Calculation

The calculations took into account the following conditions:

- Peck/Bell model
- Activation energy
  - o Al-electrolytic capacitors: 0.4 eV
  - o LCD: 0.6 eV
- Relative humidity of 85%
- Component-level stress temperatures: Ts = 85°C (specifications)
- Mean maximum temperature in use = Estimated ambient temperature in use Tu = T1H + T2 + T3
  - ➢ T1H = Ambient temperature around operating unit
  - ➢ T2 = Temperature rise inside case

- T3 = Temperature rise due to solar radiation.

- The following table was used to correct the relative humidity for higher temperatures due to solar radiation and internal heating.

	Relative Humidity									
Air Temperature [°C]	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
50	8.3	16.6	24.9	33.2	41.5	49.8	58.1	66.4	74.7	83.0
45	6.5	13.1	19.6	26.2	32.7	39.3	45.8	52.4	58.9	65.4
40	5.1	10.2	15.3	20.5	25.6	30.7	35.8	40.9	46.0	51.1
35	4.0	7.9	11.9	15.8	19.8	23.8	27.7	31.7	35.6	39.6
30	3.0	6.1	9.1	12.1	15.2	18.2	21.3	24.3	27.3	30.4
25	2.3	4.6	6.9	9.2	11.5	13.8	16.1	18.4	20.7	23.0
20	1.7	3.5	5.2	6.9	8.7	10.4	12.1	13.8	15.6	17.3
15	1.3	2.6	3.9	5.1	6.4	7.7	9.0	10.3	11.5	12.8
10	0.9	1.9	2.8	3.8	4.7	5.6	6.6	7.5	8.5	9.4
5	0.7	1.4	2.0	2.7	3.4	4.1	4.8	5.4	6.1	6.8
0	0.5	1.0	1.5	1.9	2.4	2.9	3.4	3.9	4.4	4.8
-5	0.3	0.7	1.0	1.4	1.7	2.1	2.4	2.7	3.1	3.4
-10	0.2	0.5	0.7	0.9	1.2	1.4	1.6	1.9	2.1	2.3
-15	0.2	0.3	0.5	0.6	0.8	1.0	1.1	1.3	1.5	1.6
-20	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.8	0.9
-25	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6

Table 28. Absolute humidity in g/m3 for certain air temperatures as a function of relative humidity[9]

The following equation gives an excellent approximation of the table[10].

$$Absolute\ Humidity\ (grams/m^3) = \frac{6{,}112 \times e^{\left[\frac{17{,}67 \times T}{T+243{,}5}\right]} \times rh \times 2{,}1674}{273{,}15 + T}$$

[9] Source : https://www.tis-gdv.de/tis_e/misc/klima.htm/

[10] Source: https://carnotcycle.wordpress.com/2012/08/04/how-to-convert-relative-humidity-to-absolute-humidity/

Life expectancy (years)	15
Ambiant Température under stress (°C)	85
Measured Température under stress (°C)	86
Humidity in stress (%)	85
Activation Energy (eV)	0,4

*Windsor temp with Sarnia sun	January			February			March			April			May			June		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	19,2	19,2		19,4	19,4		22,6	22,6		24,4	24,4		27,6	27,6		27,4	27,4	
Bright Sunshine (hrs/day)	5,1	4,3		5,3	5,2		5,7	6,2		5,8	7,6		6,0	8,6		5,6	9,7	
Daily extremum ambiant temperature (°C) - T1	-0,3	-0,3	-7,3	1,1	1,1	-6,3	6,7	6,7	-2,2	14,1	14,1	3,7	20,4	20,4	9,5	25,8	25,8	15,3
Temp rise due to Self-heating (°C) - T2	4,9	4,9	5,1	4,9	4,9	5,1	4,8	4,8	5,0	4,6	4,6	4,8	4,5	4,5	4,7	4,4	4,4	4,6
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	7	0	0	7	0
Relative Humidity at T1 (%)	69,6	69,6	80,2	65,9	65,9	79,3	58,9	58,9	77,3	52,6	52,6	76,6	52,4	52,4	77,6	52,7	52,7	79,5
Absolute Humidity at T1 (g/m3)	3,3	3,3	2,3	3,4	3,4	2,5	4,5	4,5	3,2	6,4	6,4	4,8	9,3	9,3	7,1	12,7	12,7	10,4
Relative humidity corrected at Tu (%)	49,8	40,4	55,1	47,1	35,7	54,7	43,2	31,1	54,4	39,6	28,3	55,4	40,3	28,0	57,5	41,1	28,6	60,1
Reference Temperature - Tu	5	8	-2,2	6	10	-1	11	17	3	19	25	9	25	31	14	30	37	20
Days per month	31	19,2	31	28	19,4	28	31	22,6	31	30	24,4	30	31	27,6	31	30	27,4	30
Days per month without sun	11,8		31	8,6		28	8,4		31	5,6		30	3,4		31	2,6		30
Hours per day with Bright Sunshine	5	4		5	5		6	6		6	8		6	9		6	10	
Hours per day without Bright Sunshine	9		15	11		14	12		12	13		11	15		9	15		9
Total duration with bright sunshine (h)	1462	1226	0	1551	1505	0	1936	2099	0	2126	2778	0	2495	3549	0	2306	3995	0
Total duration without bright sunshine (h)	1651	0	6822	1355	0	5670	1499	0	5627	1126	0	4770	745	0	4371	598	0	3902
AF temperature	48	48	51	48	48	51	45	45	48	40	40	44	34	34	38	28	28	32
AF humidity	4	7	3	5	10	3	6	15	3	8	19	3	7	19	3	7	18	3
Total AF	199	348	162	229	478	164	271	652	159	304	746	137	246	649	108	191	504	79
Test Duration with bright sunshine (h)	7	4	0	7	3	0	7	3	0	7	4	0	10	5	0	12	8	0
Test Duration without bright sunshine (h)	8	0	42	6	0	35	6	0	35	4	0	35	3	0	40	3	0	49

*Windsor temp with Sarnia sun	July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	30,1	30,1		28,3	28,3		26,3	26,3		25,4	25,4		19,6	19,6		17,4	17,4	
Bright Sunshine (hrs/day)	5,1	9,9		5,0	9,0		5,2	7,3		5,0	6,0		5,3	4,5		5,1	3,9	
Daily extremum ambiant temperature (°C) - T1	28,1	28,1	17,9	26,9	26,9	17,1	22,9	22,9	12,8	15,8	15,8	6,7	8,8	8,8	1,4	2	2	-4,3
Temp rise due to Self-heating (°C) - T2	4,3	4,3	4,5	4,3	4,3	4,6	4,4	4,4	4,6	4,6	4,6	4,8	4,7	4,7	4,9	4,9	4,9	5,0
Temp rise due to sun (°C) - T3	0	7	0	0	7	0	0	6	0	0	4	0	0	3	0	0	2	0
Relative Humidity at T1 (%)	53,6	53,6	81,5	57,3	57,3	85,6	55,7	55,7	85,2	57,1	57,1	81,3	65,1	65,1	80,3	70,9	70,9	80,6
Absolute Humidity at T1 (g/m3)	14,7	14,7	12,4	14,7	14,7	12,5	11,4	11,4	9,5	7,7	7,7	6,2	5,7	5,7	4,3	3,9	3,9	2,9
Relative humidity corrected at Tu (%)	42,1	28,9	62,2	44,9	31,7	65,1	43,1	31,9	63,9	43,3	33,9	59,6	48,1	41,0	57,5	50,9	43,5	56,1
Reference Temperature - Tu	32	40	22	31	37,9	22	27	33	17	20	25	11	14	16	6	7	9	1
Days per month	31	30,1	31	31	28,3	31	30	26,3	30	31	25,4	31	30	19,6	30	31	17,4	31
Days per month without sun	0,9		31	2,7		31	3,7		30	5,6		31	10,4		30	13,6		31
Hours per day with Bright Sunshine	5	10		5	9		5	7		5	6		5	4		5	4	
Hours per day without Bright Sunshine	15		9	14		10	13		12	11		13	10		14	9		15
Total duration with bright sunshine (h)	2286	4487	0	2129	3815	0	2062	2870	0	1923	2268	0	1567	1314	0	1338	1011	0
Total duration without bright sunshine (h)	203	0	4185	567	0	4650	694	0	5175	924	0	6045	1529	0	6390	1836	0	6975
AF temperature	25	25	28	25	25	28	30	30	33	37	37	40	42	42	45	46	46	49
AF humidity	6	18	2	5	14	2	6	14	2	6	12	3	5	7	3	4	6	3
Total AF	160	436	65	135	341	57	181	405	71	223	428	104	189	290	128	181	274	149
Test Duration with bright sunshine (h)	14	10	0	16	11	0	11	7	0	9	5	0	8	5	0	7	4	0
Test Duration without bright sunshine (h)	1	0	65	4	0	82	4	0	73	4	0	58	8	0	50	10	0	47

Average Acceleration factor	153
Total duration of test to cover 15 years (h)	857
Duration of test at CRIQ (h)	600

Table 29. Windsor ALT data for capacitor in damp heat

*Sudbury	January			February			March			April			May			June		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	20	20		21	21		25	25		25,4	25		27,1	27		28	28	
Bright Sunshine (hrs/day)	4,7	4,3		4,6	5,6		5,5	6,4		5,9	7,7		6,6	8,4		6,9	8,8	
Daily extremum ambiant temperature (°C) - T1	-8	-8	-17,9	-5,5	-5,5	-16	0,4	0,4	-10,2	9,2	9,2	-1,7	17	17	5,2	22,2	22,2	10,7
Temp rise due to Self-heating (°C) - T2	5,1	5,1	5,3	5,1	5,1	5,3	4,9	4,9	5,2	4,7	4,7	5,0	4,6	4,6	4,8	4,4	4,4	4,7
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	6	0	0	7	0
Relative Humidity at T1 (%)	71,3	71,3	79,4	64,3	64,3	77,4	56,4	56,4	75,0	49,9	49,9	74,5	48,5	48,5	77,1	52,0	52,0	82,4
Absolute Humidity at T1 (g/m3)	2,0	2,0	1,0	2,1	2,1	1,2	2,8	2,8	1,7	4,5	4,5	3,2	7,0	7,0	5,3	10,2	10,2	8,1
Relative humidity corrected at Tu (%)	49,3	40,8	52,2	45,0	34,2	51,4	40,5	28,9	51,3	37,1	26,0	53,0	37,1	25,9	56,5	40,4	28,2	61,6
Reference Temperature - Tu	-3	0	-12,6	0	4	-11	5	11	-5	14	20	3	22	28	10	27	33	15
Days per month	31	20	31	28	21	28	31	25	31	30	25,4	30	31	27,1	31	30	28	30
Days per month without sun	11		31	7		28	6		31	4,6		30	3,9		31	2		30
Hours per day with Bright Sunshine	5	4		5	6		5	6		6	8		7	8		7	9	
Hours per day without Bright Sunshine	9		15	10		14	12		12	14		10	15		9	16		8
Total duration with bright sunshine (h)	1406	1295	0	1456	1773	0	2048	2415	0	2248	2934	0	2672	3426	0	2912	3704	0
Total duration without bright sunshine (h)	1485	0	6975	1076	0	5775	1071	0	5627	938	0	4680	878	0	4185	473	0	3713
AF temperature	52	52	55	52	52	55	50	50	53	45	45	48	38	38	43	32	32	36
AF humidity	4	7	4	5	11	4	7	18	4	9	23	4	9	24	3	7	19	2
Total AF	222	367	202	281	582	209	356	872	202	407	1044	170	349	905	126	230	599	85
Test Duration with bright sunshine (h)	6	4	0	5	3	0	6	3	0	6	3	0	8	4	0	13	6	0
Test Duration without bright sunshine (h)	7	0	34	4	0	28	3	0	28	2	0	28	3	0	33	2	0	44

*Sudbury	July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	30,2	30		29,4	29		26	26		25,3	25		18,1	18		17,1	17	
Bright Sunshine (hrs/day)	6,4	9,1		5,9	8,3		6,3	6,2		6,2	4,8		5,5	3,9		4,9	3,7	
Daily extremum ambiant temperature (°C) - T1	24,8	24,8	13,4	23,4	23,4	12,4	18,1	18,1	7,8	10,3	10,3	1,7	2,6	2,6	-4,7	-4,4	-4,4	-12,7
Temp rise due to Self-heating (°C) - T2	4,4	4,4	4,6	4,4	4,4	4,7	4,5	4,5	4,8	4,7	4,7	4,9	4,9	4,9	5,0	5,0	5,0	5,2
Temp rise due to sun (°C) - T3	0	7	0	0	6	0	0	5	0	0	3	0	0	2	0	0	2	0
Relative Humidity at T1 (%)	52,6	52,6	85,6	55,1	55,1	89,6	60,8	60,8	91,7	64,7	64,7	88,4	73,1	73,1	87,2	76,0	76,0	84,1
Absolute Humidity at T1 (g/m3)	12,0	12,0	9,9	11,6	11,6	9,8	9,4	9,4	7,5	6,2	6,2	4,8	4,2	4,2	3,0	2,7	2,7	1,6
Relative humidity corrected at Tu (%)	41,2	28,8	64,6	43,0	31,1	67,4	46,7	35,4	67,8	48,3	39,2	63,8	53,0	45,7	61,2	53,4	46,1	56,8
Reference Temperature - Tu	29	36	18	28	33,8	17	23	28	13	15	18	7	7	10	0	1	3	-7
Days per month	31	30,2	31	31	29,4	31	30	26	30	31	25,3	31	30	18,1	30	31	17,1	31
Days per month without sun	0,8		31	1,6		31	4		30	5,7		31	11,9		30	13,9		31
Hours per day with Bright Sunshine	6	9		6	8		6	6		6	5		6	4		5	4	
Hours per day without Bright Sunshine	16		9	14		10	13		12	11		13	9		15	9		15
Total duration with bright sunshine (h)	2901	4121	0	2606	3678	0	2444	2432	0	2354	1821	0	1505	1047	0	1253	952,5	0
Total duration without bright sunshine (h)	186	0	3953	342	0	4534	750	0	5175	941	0	6045	1678	0	6570	1793	0	7161
AF temperature	29	29	32	29	29	33	33	33	37	40	40	44	45	45	49	50	50	53
AF humidity	7	18	2	6	15	2	5	10	2	4	8	2	4	5	2	3	5	3
Total AF	197	512	67	180	428	61	165	344	68	182	317	94	160	236	117	171	254	155
Test Duration with bright sunshine (h)	15	8	0	14	9	0	15	7	0	13	6	0	9	4	0	7	4	0
Test Duration without bright sunshine (h)	1	0	59	2	0	75	5	0	76	5	0	64	10	0	56	10	0	46

Average Acceleration factor	164
Total duration of test to cover 15 years (h)	801
Duration of test at CRIQ (h)	600

Table 30. Sudbury ALT data for capacitor in damp heat

Life expectancy (years)	15
Ambiant Température under stress (°C)	85
Measured Température under stress (°C)	86
Humidity in stress (%)	85
Activation Energy (eV)	0,6

*Windsor temp with Sarnia sun	January			February			March			April			May			June		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	19,2	19,2		19,4	19,4		22,6	22,6		24,4	24,4		27,6	27,6		27,4	27,4	
Bright Sunshine (hrs/day)	5,1	4,3		5,3	5,2		5,7	6,2		5,8	7,6		6,0	8,6		5,6	9,7	
Daily extremum ambiant temperature (°C) - T1	-0,3	-0,3	-7,3	1,1	1,1	-6,3	6,7	6,7	-2,2	14,1	14,1	3,7	20,4	20,4	9,5	25,8	25,8	15,3
Temp rise due to Self-heating (°C) - T2	10,6	10,6	11,1	10,5	10,5	11,1	10,0	10,0	10,7	9,4	9,4	10,3	9,0	9,0	9,8	8,5	8,5	9,4
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	7	0	0	7	0
Relative Humidity at T1 (%)	69,6	69,6	80,2	65,9	65,9	79,3	58,9	58,9	77,3	52,6	52,6	76,6	52,4	52,4	77,6	52,7	52,7	79,5
Absolute Humidity at T1 (g/m3)	3,3	3,3	2,3	3,4	3,4	2,5	4,5	4,5	3,2	6,4	6,4	4,8	9,3	9,3	7,1	12,7	12,7	10,4
Relative humidity corrected at Tu (%)	34,6	28,5	36,8	33,2	25,5	36,8	31,4	22,9	37,6	30,1	21,8	39,7	31,6	22,3	42,6	33,2	23,3	46,0
Reference Temperature - Tu	10,3	13	3,8	12	16	5	17	22	9	24	29	14	29	36	19	34	41	25
Days per month	31	19,2	31	28	19,4	28	31	22,6	31	30	24,4	30	31	27,6	31	30	27,4	30
Days per month without sun	11,8		31	8,6		28	8,4		31	5,6		30	3,4		31	2,6		30
Hours per day with Bright Sunshine	5,07	4,26		5,3	5,2		5,7	6,2		5,8	7,6		6,0	8,6		5,6	9,7	
Hours per day without Bright Sunshine	9,33		14,67	10,5		13,5	11,9		12,1	13,4		10,6	14,6		9,4	15,3		8,7
Total duration with bright sunshine (h)	1462	1226	0	1551	1505	0	1936	2099	0	2126	2778	0	2495	3549	0	2306	3995	0
Total duration without bright sunshine (h)	1651	0	6822	1355	0	5670	1499	0	5627	1126	0	4770	745	0	4371	598	0	3902
AF temperature	179,2	137,2	317,9	160,3	111,0	292,5	103,6	66,8	208,8	59,6	37,9	130,7	38,0	23,2	83,8	26,1	15,9	54,6
AF humidity	10,9	18,4	9,3	12,2	24,7	9,2	14,1	32,7	8,7	15,8	37,5	7,6	13,9	35,3	6,3	12,2	31,3	5,1
Total AF	1961	2518	2944	1949	2744	2705	1460	2186	1826	944	1422	991	527	819	528	319	497	280
Test Duration with bright sunshine (h)	0,7	0,5	0,0	1	1	0	1	1	0	2	2	0	5	4	0	7	8	0
Test Duration without bright sunshine (h)	0,8	0,0	2,3	1	0	2	1	0	3	1	0	5	1	0	8	2	0	14

*Windsor temp with Sarnia sun	July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	30,1	30,1		28,3	28,3		26,3	26,3		25,4	25,4		19,6	19,6		17,4	17,4	
Bright Sunshine (hrs/day)	5,1	9,9		5,0	9,0		5,2	7,3		5,0	6,0		5,3	4,5		5,1	3,9	
Daily extremum ambiant temperature (°C) - T1	28,1	28,1	17,9	26,9	26,9	17,1	22,9	22,9	12,8	15,8	15,8	6,7	8,8	8,8	1,4	2	2	-4,3
Temp rise due to Self-heating (°C) - T2	8,4	8,4	9,2	8,4	8,4	9,2	8,8	8,8	9,6	9,3	9,3	10,0	9,9	9,9	10,4	10,4	10,4	10,9
Temp rise due to sun (°C) - T3	0	7	0	0	7	0	0	6	0	0	4	0	0	3	0	0	2	0
Relative Humidity at T1 (%)	53,6	53,6	81,5	57,3	57,3	85,6	55,7	55,7	85,2	57,1	57,1	81,3	65,1	65,1	80,3	70,9	70,9	80,6
Absolute Humidity at T1 (g/m3)	14,7	14,7	12,4	14,7	14,7	12,5	11,4	11,4	9,5	7,7	7,7	6,2	5,7	5,7	4,3	3,9	3,9	2,9
Relative humidity corrected at Tu (%)	34,3	23,8	48,2	36,4	26,0	50,3	34,3	25,6	48,2	33,2	26,2	43,4	35,5	30,4	40,6	36,1	31,0	38,3
Reference Temperature - Tu	36	44	27	35	42,0	26	32	37	22	25	29	17	19	21	12	12	15	7
Days per month	31	30,1	31	31	28,3	31	30	26,3	30	31	25,4	31	30	19,6	30	31	17,4	31
Days per month without sun	0,9		31	2,7		31	3,7		30	5,6		31	10,4		30	13,6		31
Hours per day with Bright Sunshine	5,1	9,9		5,0	9,0		5,2	7,3		5,0	6,0		5,3	4,5		5	4	
Hours per day without Bright Sunshine	15,0		9,0	14,0		10,0	12,5		11,5	11,0		13,0	9,8		14,2	9		15
Total duration with bright sunshine (h)	2286	4487	0	2129	3815	0	2062	2870	0	1923	2268	0	1567	1314	0	1338	1011	0
Total duration without bright sunshine (h)	203	0	4185	567	0	4650	694	0	5175	924	0	6045	1529	0	6390	1836	0	6975
AF temperature	22,4	13,3	45,3	24,3	15,1	48,0	31,9	21,2	65,6	52,7	37,9	103,6	88,4	71,4	156,5	149,3	121,3	247,9
AF humidity	11,1	29,6	4,5	9,6	23,4	4,0	11,2	24,3	4,5	12,2	22,9	6,0	10,2	15,4	7,1	9,8	14,6	8,3
Total AF	249	394	205	232	353	194	357	514	297	645	868	619	904	1099	1116	1457	1768	2065
Test Duration with bright sunshine (h)	9	11	0	9	11	0	6	6	0	3	3	0	2	1	0	1	1	0
Test Duration without bright sunshine (h)	1	0	20	2	0	24	2	0	17	1	0	10	2	0	6	1	0	3

Average Acceleration factor	579
Total duration of test to cover 15 years (h)	227
Duration of test at CRIQ (h)	600

Table 31. Windsor ALT data for LCD in damp heat

*Sudbury	January			February			March			April			May			June		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	20	20		21	21		25	25		25,4	25		27,1	27		28	28	
Bright Sunshine (hrs/day)	4,7	4,3		4,6	5,6		5,5	6,4		5,9	7,7		6,6	8,4		6,9	8,8	
Daily extremum ambiant temperature (°C) - T1	-8	-8	-17,9	-5,5	-5,5	-16	0,4	0,4	-10,2	9,2	9,2	-1,7	17	17	5,2	22,2	22,2	10,7
Temp rise due to Self-heating (°C) - T2	11,2	11,2	12,0	11,0	11,0	11,8	10,5	10,5	11,4	9,8	9,8	10,7	9,2	9,2	10,1	8,8	8,8	9,7
Temp rise due to sun (°C) - T3	0	3	0	0	4	0	0	5	0	0	6	0	0	6	0	0	7	0
Relative Humidity at T1 (%)	71,3	71,3	79,4	64,3	64,3	77,4	56,4	56,4	75,0	49,9	49,9	74,5	48,5	48,5	77,1	52,0	52,0	82,4
Absolute Humidity at T1 (g/m3)	2,0	2,0	1,0	2,1	2,1	1,2	2,8	2,8	1,7	4,5	4,5	3,2	7,0	7,0	5,3	10,2	10,2	8,1
Relative humidity corrected at Tu (%)	32,5	27,1	31,8	30,1	23,2	31,8	28,2	20,5	33,2	27,3	19,4	36,5	28,5	20,1	40,6	31,8	22,5	45,7
Reference Temperature - Tu	3	6	-5,9	5	10	-4	11	16	1	19	25	9	26	33	15	31	38	20
Days per month	31	20	31	28	21	28	31	25	31	30	25,4	30	31	27,1	31	30	28	30
Days per month without sun	11		31	7		28	6		31	4,6		30	3,9		31	2		30
Hours per day with Bright Sunshine	5	4		5	6		5	6		6	8		7	8		7	9	
Hours per day without Bright Sunshine	9		15	10		14	12		12	14		10	15		9	16		8
Total duration with bright sunshine (h)	1406	1295	0	1456	1773	0	2048	2415	0	2248	2934	0	2672	3426	0	2912	3704	0
Total duration without bright sunshine (h)	1485	0	6975	1076	0	5775	1071	0	5627	938	0	4680	878	0	4185	473	0	3713
AF temperature	337	264	798	274	192	674	169	109	406	86	53	201	48	30	116	33	21	77
AF humidity	13	21	14	16	32	14	19	44	12	21	51	10	18	46	7	14	34	5
Total AF	4366	5508	10898	4313	6041	9185	3180	4805	4939	1761	2714	1907	888	1373	833	456	705	399
Test Duration with bright sunshine (h)	0	0	0	0	0	0	1	1	0	1	1	0	3	2	0	6	5	0
Test Duration without bright sunshine (h)	0	0	1	0	0	1	0	0	1	1	0	2	1	0	5	1	0	9

*Sudbury	July			August			September			October			November			December		
	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night	Day	Sun	Night
Days with measurable sunshine	30,2	30		29,4	29		26	26		25,3	25		18,1	18		17,1	17	
Bright Sunshine (hrs/day)	6,4	9,1		5,9	8,3		6,3	6,2		6,2	4,8		5,5	3,9		4,9	3,7	
Daily extremum ambiant temperature (°C) - T1	24,8	24,8	13,4	23,4	23,4	12,4	18,1	18,1	7,8	10,3	10,3	1,7	2,6	2,6	-4,7	-4,4	-4,4	-12,7
Temp rise due to Self-heating (°C) - T2	8,6	8,6	9,5	8,7	8,7	9,6	9,1	9,1	9,9	9,7	9,7	10,4	10,4	10,4	10,9	10,9	10,9	11,6
Temp rise due to sun (°C) - T3	0	7	0	0	6	0	0	5	0	0	3	0	0	2	0	0	2	0
Relative Humidity at T1 (%)	52,6	52,6	85,6	55,1	55,1	89,6	60,8	60,8	91,7	64,7	64,7	88,4	73,1	73,1	87,2	76,0	76,0	84,1
Absolute Humidity at T1 (g/m3)	12,0	12,0	9,9	11,6	11,6	9,8	9,4	9,4	7,5	6,2	6,2	4,8	4,2	4,2	3,0	2,7	2,7	1,6
Relative humidity corrected at Tu (%)	32,9	23,2	48,7	34,1	24,9	50,5	36,0	27,6	49,5	35,8	29,2	44,9	37,4	32,5	41,3	36,1	31,3	36,1
Reference Temperature - Tu	33	40	23	32	38,1	22	27	32	18	20	24	12	13	15	6	7	9	-1
Days per month	31	30,2	31	31	29,4	31	30	26	30	31	25,3	31	30	18,1	30	31	17,1	31
Days per month without sun	0,8		31	1,6		31	4		30	5,7		31	11,9		30	13,9		31
Hours per day with Bright Sunshine	6	9		6	8		6	6		6	5		6	4		5	4	
Hours per day without Bright Sunshine	16		9	14		10	13		12	11		13	9		15	9		15
Total duration with bright sunshine (h)	2901	4121	0	2606	3678	0	2444	2432	0	2354	1821	0	1505	1047	0	1253	952,5	0
Total duration without bright sunshine (h)	186	0	3953	342	0	4534	750	0	5175	941	0	6045	1678	0	6570	1793	0	7161
AF temperature	28	17	63	31	20	68	45	31	95	79	60	153	142	117	256	250	206	504
AF humidity	13	31	4	11	26	4	10	20	4	10	17	5	9	13	7	10	14	10
Total AF	350	541	277	351	520	270	439	614	402	790	1021	837	1260	1509	1752	2441	2929	4912
Test Duration with bright sunshine (h)	8	8	0	7	7	0	6	4	0	3	2	0	1	1	0	1	0	0
Test Duration without bright sunshine (h)	1	0	14	1	0	17	2	0	13	1	0	7	1	0	4	1	0	1

Average Acceleration factor	849
Total duration of test to cover 15 years (h)	155
Duration of test at CRIQ (h)	600

Table 32. Sudbury ALT data for LCD in damp heat

To simulate a 15-year service life, the temperature and humidity test varies between 155 and 857 hours in conditions of 85°C and 85% relative humidity, depending on the failure modes and geographic location. A 600-hour test was used to cover the majority of cases.

During testing, the meters were powered and operated with a 5-A load, as specified in the parameters in Section 5.3.

7 Results

This section describes the test conditions and reviews the observations made during testing.

7.1 HTOL (High Temperature Operating Life)

The high temperature test at 85°C was performed in an environmental chamber at CRIQ. It was started on February 24, 2020, and concluded on July 28, 2020. Testing was paused and the laboratory closed from March 24 and May 15 to comply with Québec public health orders.

Each week, the test was stopped to test whether the meters were still functioning normally. The meters were subjected to a total of 2426 hours of testing.

At the conclusion of testing, all meters but one were still functional. Aging was apparent on the plastics, which were discoloured, and on the LCD, which had started to get darker but remained functional. Accuracy testing showed that the meters were still within their accuracy classes.

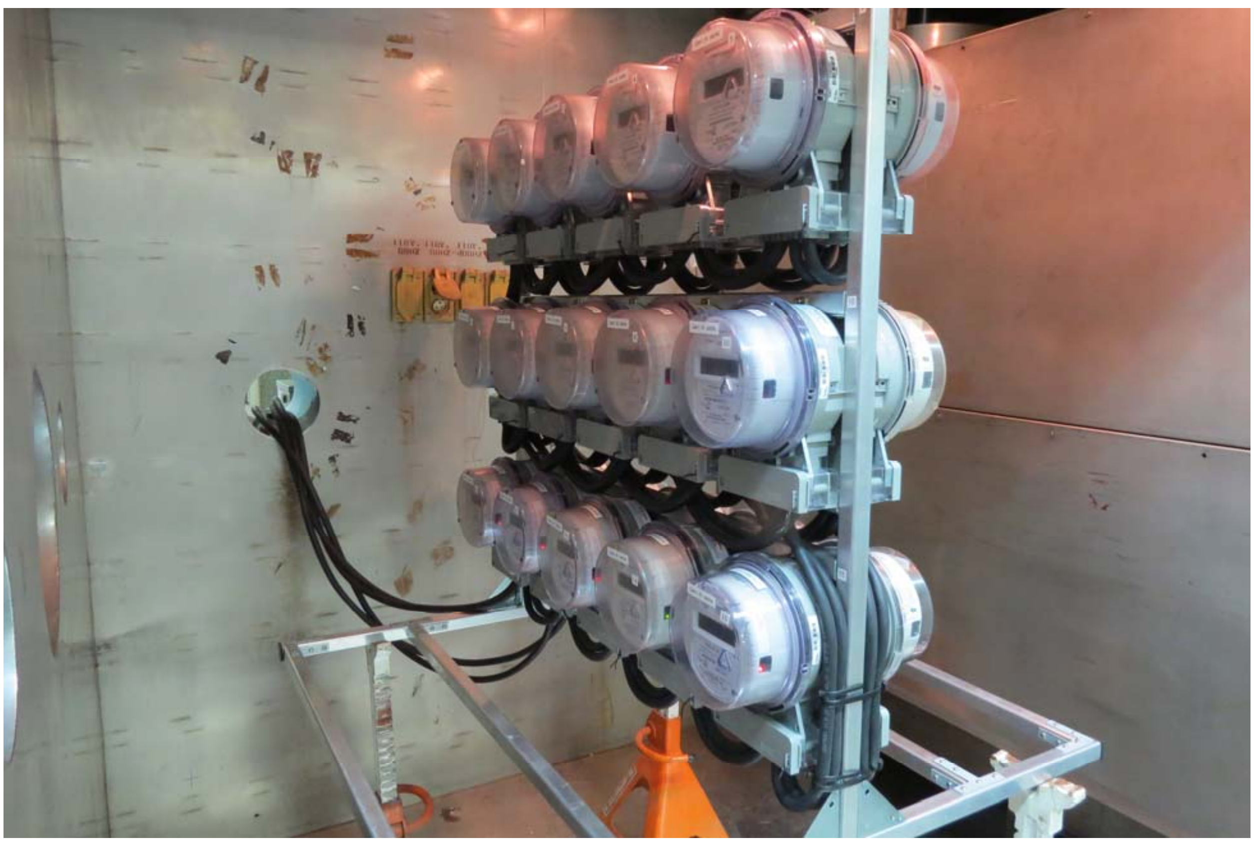


Figure 21. Meters at start of HTOL testing

The failure log reveals a prevalence of communication problems with the GEN1 meters. These problems were generally related to a problem with capacitor C21.

meter	GEN	failure time detectio	failure classificatio	root cause of failur
J3745300	3	389	comm	2x normal burden
J2648975	1	405	comm	C21 failed
J2277045	1	565	comm	C21 failed
J2898837	1	935	comm	C21 failed
J2106108	1	927	comm	C21 failed
J2103744	1	935	comm	C21 failed
J2573239	1	1775	comm	C21 failed
J2969805	3	1735	comm	unknown
J2887565	1	2399	comm	C21 failed
J2574860	1	1415	comm	C21 failed
J2241226	1	2119	comm	C21 failed
J2229099	1	1319	comm	C21 failed
J2187968	1	1663	comm	C21 failed
J2103744	1	1527	comm	C21 failed
J2074857	1	2399	comm	C21 failed
J2038889	1	2215	comm	C21 failed
J2038889	1	2103	xfo	
J3745300	3	1759	xfo	
J2038889	1	2103	segment	
J2573239	1	1143	segment	

Table 33. HTOL failure log

7.1.1 Communication failure

Of the 19 GEN1 meters tested, 14 stopped communicating. In all cases, the communication problem could be linked to the capacitors. Of the 11 GEN3 meters, two stopped communicating. Neither of the failures were related to a known failure mechanism (burden 2x higher and unknown original problem).

7.1.1.1 GEN1—Capacitors

Of the 19 GEN1 meters tested, capacitor C21 had reached its end of life on 18 of them by the end of the test (see Section 5.6.3 for the definition of the end-of-life criterion). Table 34 presents capacitance values over the course of the test. The capacitance values highlighted in yellow are under the end-of-life criterion threshold.

		Capacity (F)													
		2020-02-26	2020-03-04	2020-03-12	2020-03-17	2020-03-24	2020-05-19	2020-05-27	2020-06-02	2020-06-09	2020-06-17	2020-06-22	2020-06-29	2020-07-07	2020-07-14
1	J2038889	1,14	0,85	0,89	1,00	1,21	0,68	0,60	0,40	0,42	0,52	0,34	0,35	0,20	0,23
2	J2074857	1,07	1,03	0,93	0,84	0,92	0,70	0,44	0,35	0,30	0,15	0,23	0,16	0,15	0,15
3	J2103744	0,81	0,46	0,20	0,26	0,31	0,25	0,23	0,23	0,23	0,17	0,18	0,17	0,24	0,19
4	J2177071	1,21	1,15	1,16	1,12	1,22	1,09	1,11	1,09	1,08	0,96	0,95	0,91	0,99	0,91
5	J2187968	1,28	1,35	1,26	1,25	1,31	1,19	1,26	1,00	1,00	0,82	0,58	0,41	0,22	0,16
6	J2215016	0,92	0,82	0,87	0,82	1,09	0,90	0,93	0,90	0,90	0,82	0,85	0,84	0,85	0,79
7	J2229099	1,11	0,83	0,68	0,70	0,72	0,48	0,44	0,30	0,34	0,15	0,21	0,17	0,16	0,15
8	J2241226	1,09	1,05	1,01	0,97	1,20	0,98	0,89	0,88	0,69	0,83	0,81	0,81	0,81	0,83
9	J2277045	0,91	0,62	0,30	0,29	0,31	0,22	0,14	0,16	0,12	0,17	0,14	0,15	0,22	0,24
10	J2573239	1,18	1,14	1,19	1,10	1,14	1,08	1,03	1,07	1,02	1,00	0,94	0,97	1,21	0,78
11	J2574860	1,12	1,10	1,07	1,03	1,10	0,92	0,65	0,50	0,49	0,51	0,44	0,28	0,26	0,17
12	J2627439	1,22	1,22	1,22	1,14	1,21	1,17	1,10	1,09	1,12	1,09	1,10	0,94	0,97	0,93
13	J2648975	1,03	0,51	0,19	0,22	0,13	0,13	0,13	0,15	0,12	0,11	0,15	0,13	0,22	0,16
14	J2106108	0,95	0,68	0,47	0,36	0,42	0,16	0,31	0,32	0,25	0,25	0,16	0,17	0,24	0,18
15	J2887565	1,28	1,20	1,16	1,14	1,06	1,13	1,11	1,06	1,03	0,97	0,96	0,86	0,95	0,91
16	J2898837	1,11	1,03	0,95	1,12	1,01	0,46	0,28	0,19	0,24	0,28	0,14	0,15	0,15	0,20
17	J2949630	1,01	1,07	1,07	1,02	1,12	0,81	0,59	0,56	0,46	0,29	0,44	0,32	0,34	0,34
18	J2969282	1,39	1,20	1,20	1,19	1,29	1,23	1,14	1,21	1,01	1,09	1,10	1,08	1,07	1,11
19	J2969805	1,13	1,13	1,03	1,12	1,20	0,98	0,79	0,79	0,67	0,54	0,43	0,39	0,50	0,30

Table 34. Capacitance of capacitor C21 during the HTOL test

Figure 22 illustrates a few of the capacitors that leaked during the test. These photos are provided for information only and do not systematically correspond to a failure.

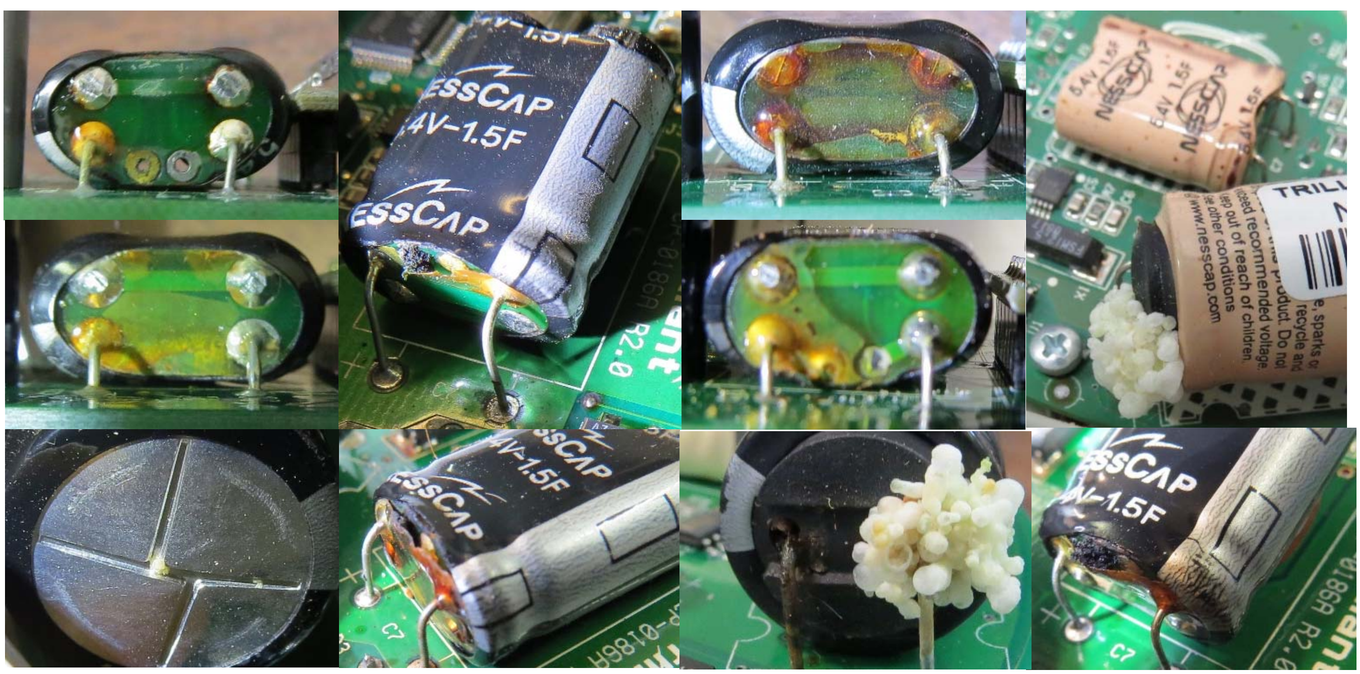


Figure 22. Capacitors failures

7.1.2 Power failure

During the test, only two meters suffered a power transformer failure. The first, meter J2074857, is a GEN1 Focus with a FALCO transformer. The second, meter J3745300, is a GEN3 Focus with a Zettler Magnetics transformer. In the GEN3 meter, a problem on the metrology board caused the load to increase (6 VA instead of 2.3-2.5 VA), which caused the transformer to fail. This failure will not be considered since it was caused by another component. Unfortunately, an accurate Weibull distribution cannot be produced from a single failure. This failure will therefore not be analyzed in Section 8.

Figure 23. FALCO transformer from J2074857

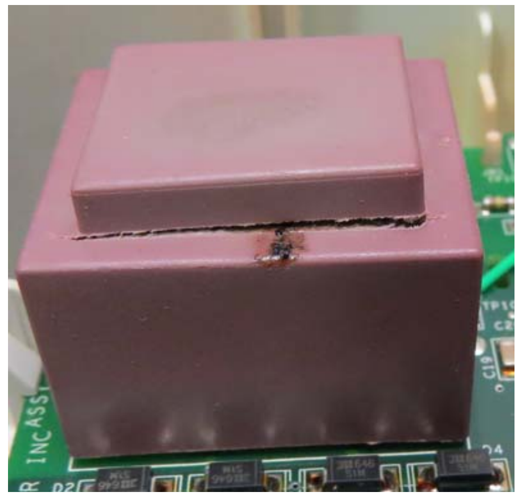


Figure 24. Zettler Magnetics transformer from J3745300

7.1.3 LCD failure

In two cases out of 19 (GEN1), the LCD had failures related to the disappearance of LCD segments. Unfortunately, an accurate Weibull distribution cannot be produced from just two failures. This failure will therefore not be analyzed in Section 8.

Figure 25. Missing segments on meter J2573239

Figure 26. Missing segments on meter J2038889

7.2 Thermal cycles

Thermal cycle testing started on May 28, 2020, and concluded on July 9, 2020. The test subjected meters to 717 80-minute thermal cycles from -40 to +85°C.Each week, the test was stopped to test whether the meters were still functioning normally. Accuracy testing showed that the meters were still within their accuracy classes after the test.

Figure 27. Meters 1 to 15 before the test

Figures 27 and 28 show the meters before the start of testing.

Figure 28. Meters 16 to 30 before the test

Figure 29 graphs the temperatures measured inside the meters through a complete cycle on June 3, 2020, at 4:15 p.m. The meters at each corner (#1, #5 and #11) and in the middle (#8) of the testbed were equipped with thermocouples, which were glued to the Faraday cage of the communications boards. The curves show that thermal equilibrium was reached in every cycle.

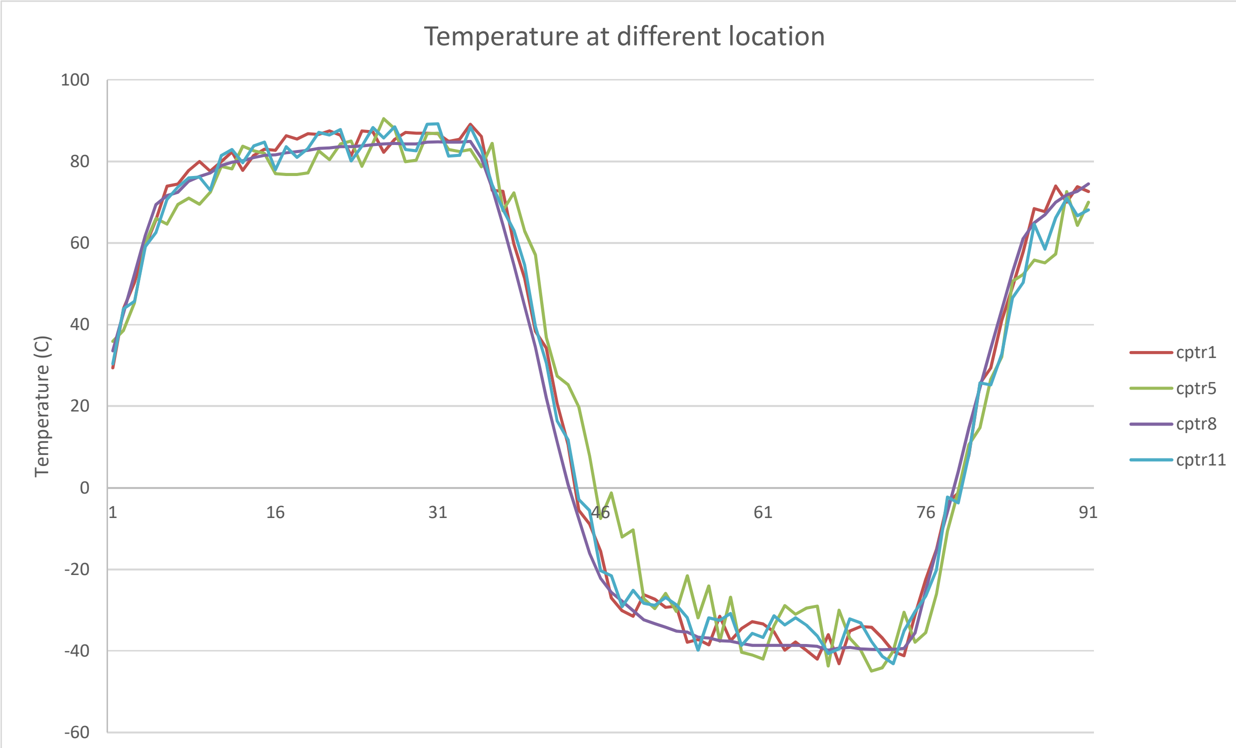


Figure 29. Temperature measured inside meters 1, 5, 8 and 11

Table 35 lists the failures observed during the test. Sections 7.2.1 to 7.2.3 review each observed failure type.

	Failures logged			
meter	failure time d	failure	root cause of failur	GEN
J2573411	128	Comm	C21	GEN1
J2965534	577	Comm	unknown	GEN1
J3362351	524	Comm	J1 issue	GEN3
J2965534	524	XFO	open primary windin	GEN1
J2970501	98	XFO	open primary windin	GEN1
J3322671	218	XFO	open primary windin	GEN3
J2192387	358	LCD	black spot	GEN1
J2218302	728	LCD	black spot	GEN1
J2545300	458	LCD	black spot	GEN1
J2965534	583,5	LCD	black spot	GEN1

Table 35. Log of failures during thermal cycle testing

There were not enough occurrences of the failures observed during this test to estimate the failures and produce a Weibull distribution.

7.2.1 Communication failure

Of the 19 GEN1 meters tested, two experienced communications problems. The communication problem could be traced to the capacitor C21 in one of the two cases. The other is of unknown origin.

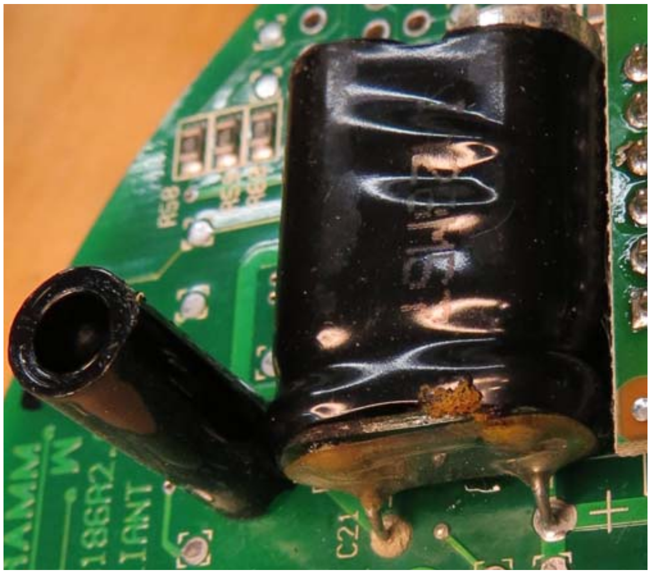


Figure 30. Condition of C21 on meter #10 – J2573411

Of the 11 GEN3 meters tested, only one experienced communications problems. The only observed failure was caused by a broken solder joint on connector J1.

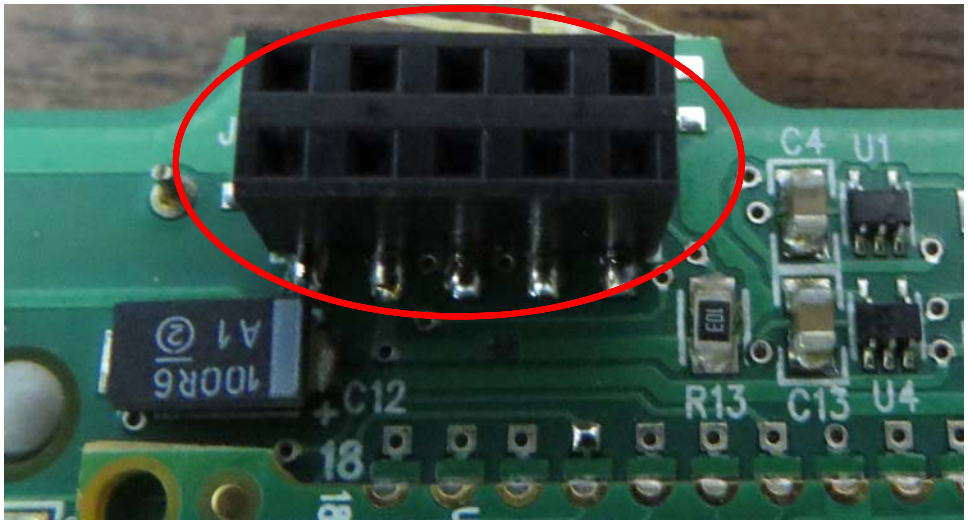


Figure 31. Cracked solder on connector J1

In reference to Section 3.3.2 on the failures caused by connector J1, it is important to note that of the 11 GEN3 meters tested, only one was an older generation model without the tripod to for mechanical stress relief. The other ten were from the new generation. **<u>The only meter that failed at connector J1 was the unit without the manufacturer's design revision.</u>**

7.2.2 Power failure

Figures 32, 33 and 34 show the meters that suffered a transformer failure. In all cases, the defective transformer had an open primary winding and was made by FALCO.

Figure 32. XFO failure on meter #19 – 2970501

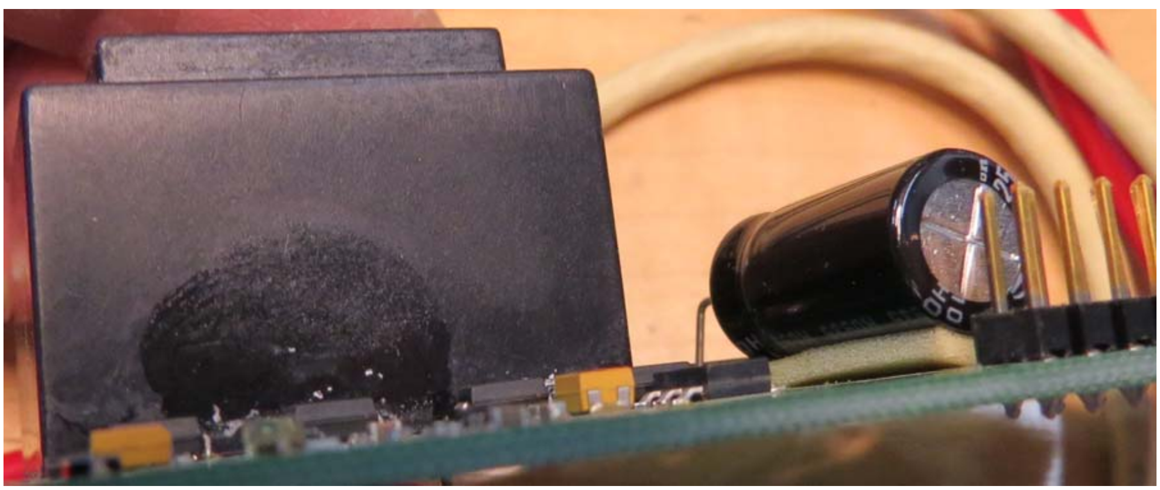


Figure 33. XFO failure on meter #20 – J3322671

Figure 34. XFO failure on meter #17 – J2965534

7.2.3 LCD

In four cases out of 19 (GEN1), the LCD had failures related to the appearance of black spots on the LCD. Unfortunately, an accurate Weibull distribution cannot be produced from just four failures.

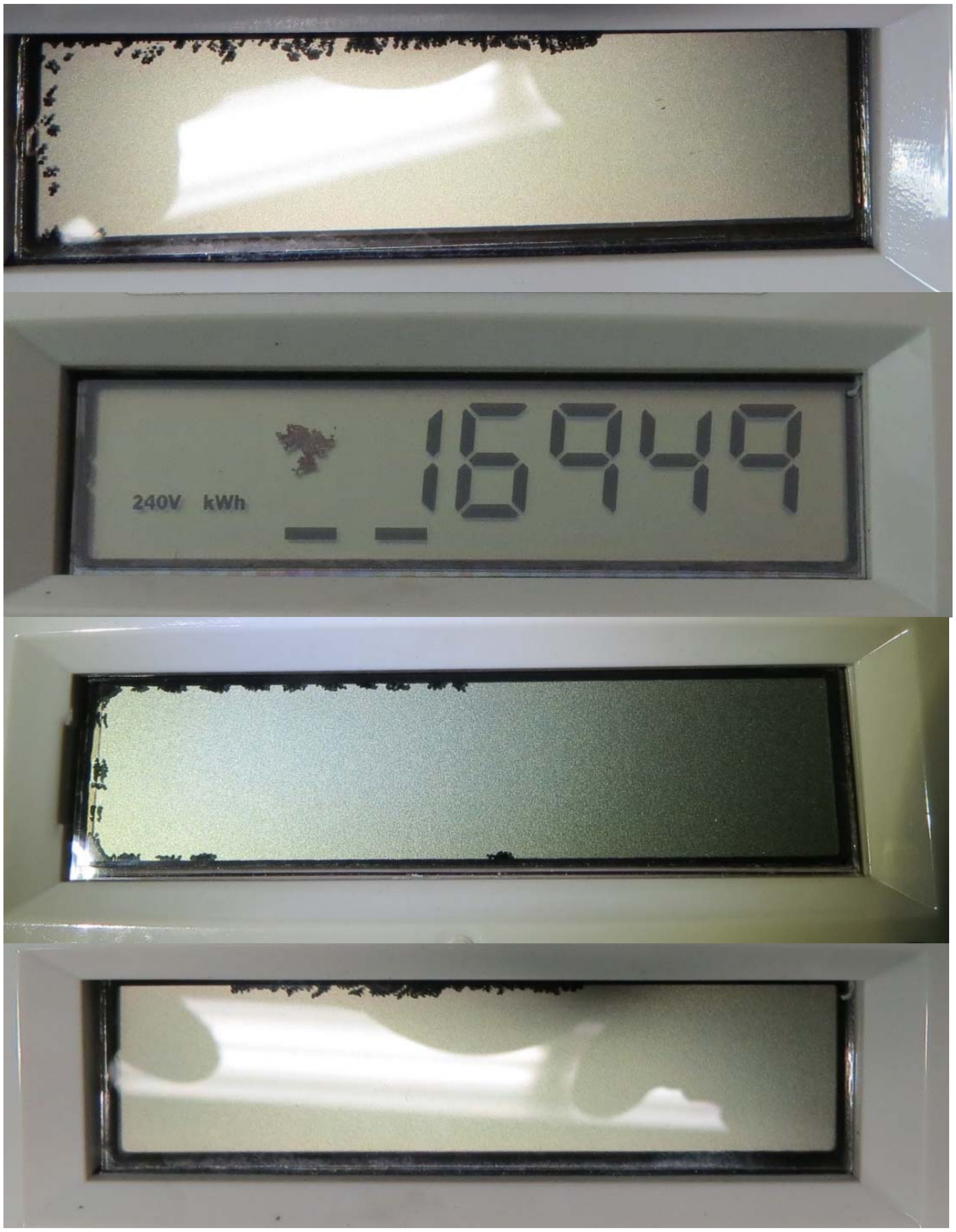


Figure 35. Spots observed on LCDs

7.3 Temperature and humidity

Damp heat testing started on March 9, 2020, but had to be paused due to the closure of the laboratory and Hydro-Québec's offices from March 24 to May 12, 2020. Testing resumed on May 13 and concluded on May 26, 2020. Each week, the test was stopped to test whether the meters were still functioning normally. In all, the equipment was exposed to damp heat at 85°C and 85% RH for 632 hours. Figure 36 shows the equipment before the test. Figures 37 and 38 show the equipment after the test.

Figure 36. Meter testbed in environmental chamber for damp heat testing

Figure 37. Meters 1 to 15 after the test

Figure 38. Meters 16 to 30 after the test

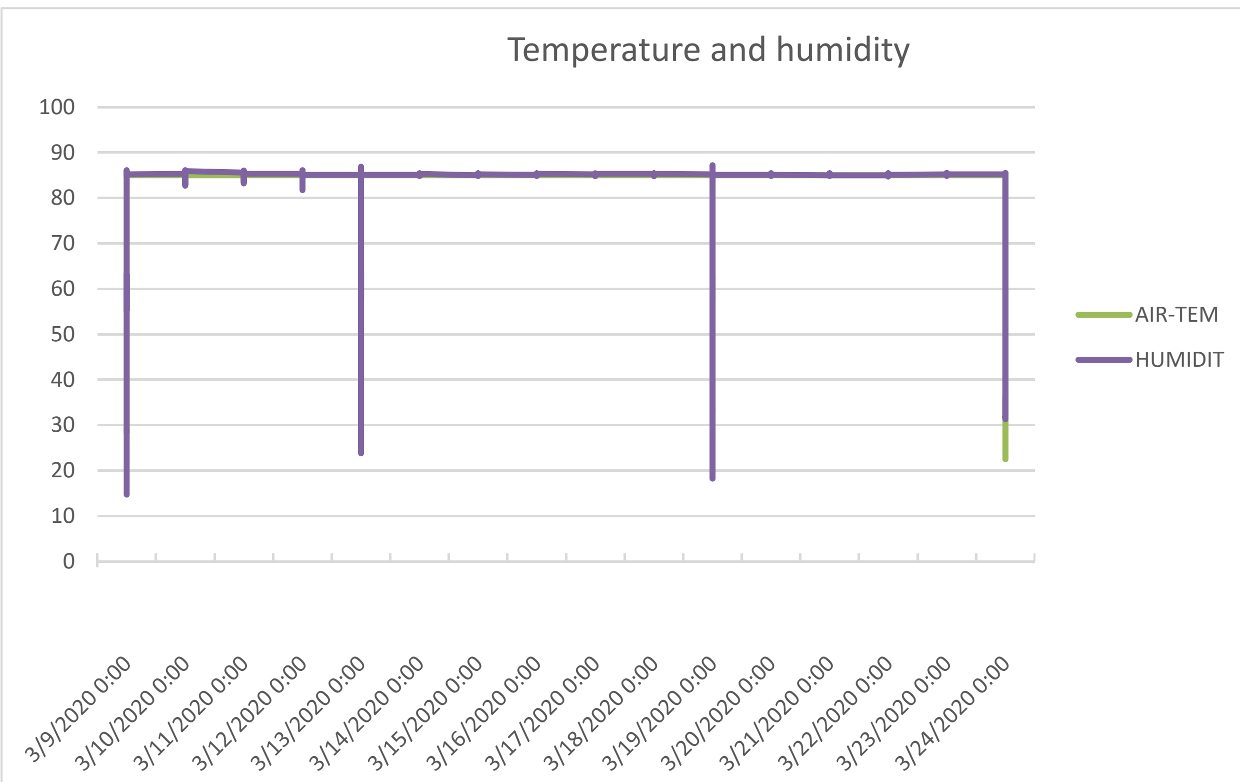


Figure 39. Temperature and humidity from March 9 to March 24, 2020

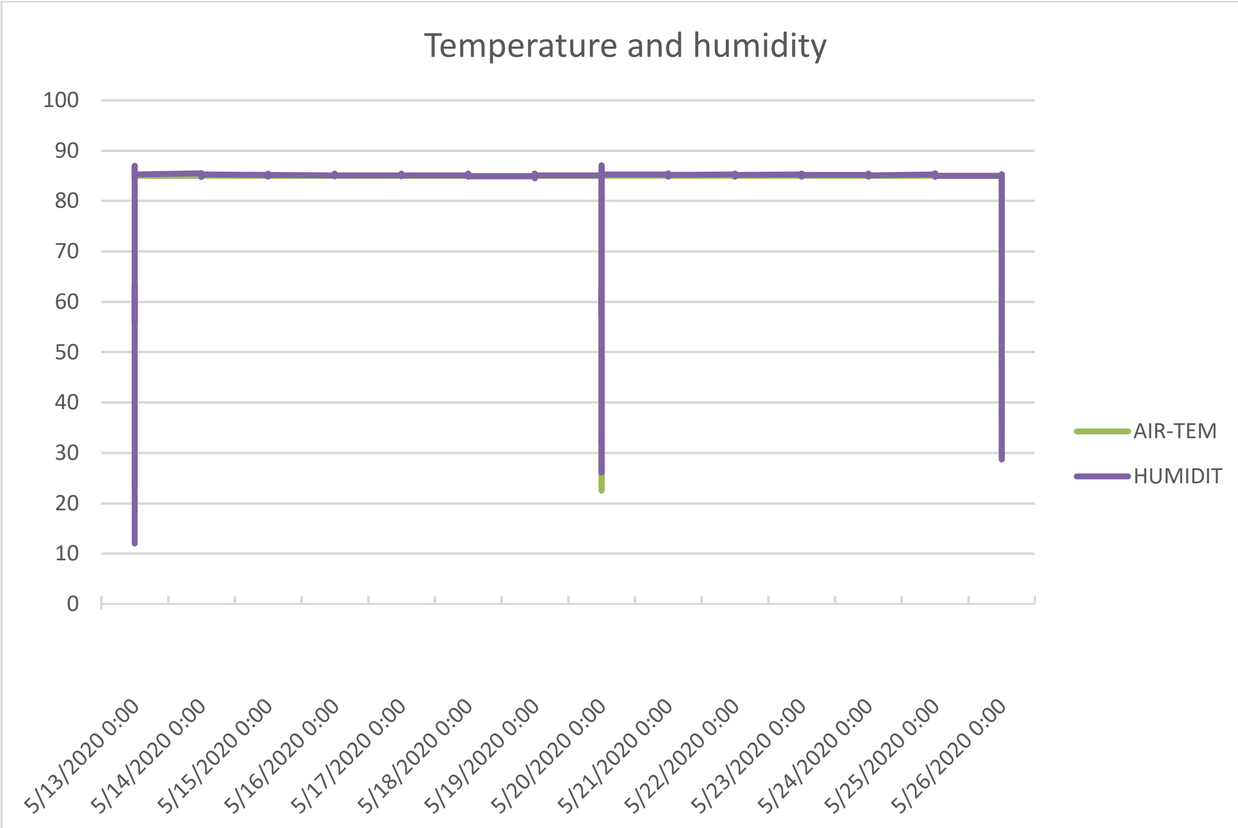


Figure 40. Temperature and humidity from May 13 to May 26, 2020

Figures 39 and 40 show the temperature and humidity in the environmental chamber during the test. The data was measured with a thermocouple mounted in the chamber. The valleys seen in the curves correspond to when the test was paused to perform functionality testing, about once a week.

Table 36 lists the failures observed during the test. Sections 7.3.1 to 7.3.5 review each observed failure type.

Failures logged at 85C with RH = 85%				
mete	failure time detectio	failure classificatio	root cause of failu	GEN
J2220748	60	Comm	C21 defect	Gen1
J2050162	84	Comm	CAP ok	Gen1
J3686949	93	Comm	J1 issue	Gen3
J3781647	199	XFO	XFO dead	Gen3
J2050162	229	LCD	dark LCD	Gen1
J2076164	229	LCD	dark LCD	Gen1
J2176865	229	LCD	dark LCD	Gen1
J2627943	229	LCD	dark LCD	Gen1
J2627943	317	Comm	C21 defect	Gen1
J2220748	340	LCD	dark LCD	Gen1
J2180811	340	LCD	dark LCD	Gen1
J2239994	340	LCD	dark LCD	Gen1
J2261741	340	LCD	dark LCD	Gen1
J2573558	340	LCD	dark LCD	Gen1
J2597250	340	LCD	dark LCD	Gen1
J2695237	340	LCD	dark LCD	Gen1
J2200102	491	LCD	dark LCD	Gen1
J2905935	491	LCD	dark LCD	Gen1
J2965870	491	LCD	missing segment	Gen1
J3366877	491	LCD	dark LCD	Gen3
J2597250	525	Comm	C21 defect	Gen1
J2552045	632	Comm	C21 defect	Gen1
J2552045	491	LCD	dark LCD	Gen1
J2881406	627	LCD	dark LCD	Gen1
J2890621	627	LCD	dark LCD	Gen1
J2905935	632	Comm	C21 defect	Gen1
J2965870	627	LCD	dark LCD	Gen1
J2969318	627	LCD	dark LCD	Gen1
J2970555	627	LCD	dark LCD	Gen1
J2970555	627	LCD	missing segment	Gen1

Table 36. Failures logged during damp heat test

7.3.1 Communication problem

7.3.1.1 GEN1—Capacitors

Of the 19 meters tested, six stopped communicating during the test. In all cases, the communication problem could be linked to the advanced degradation of the C21 capacitors. The photos below document some of the observations.

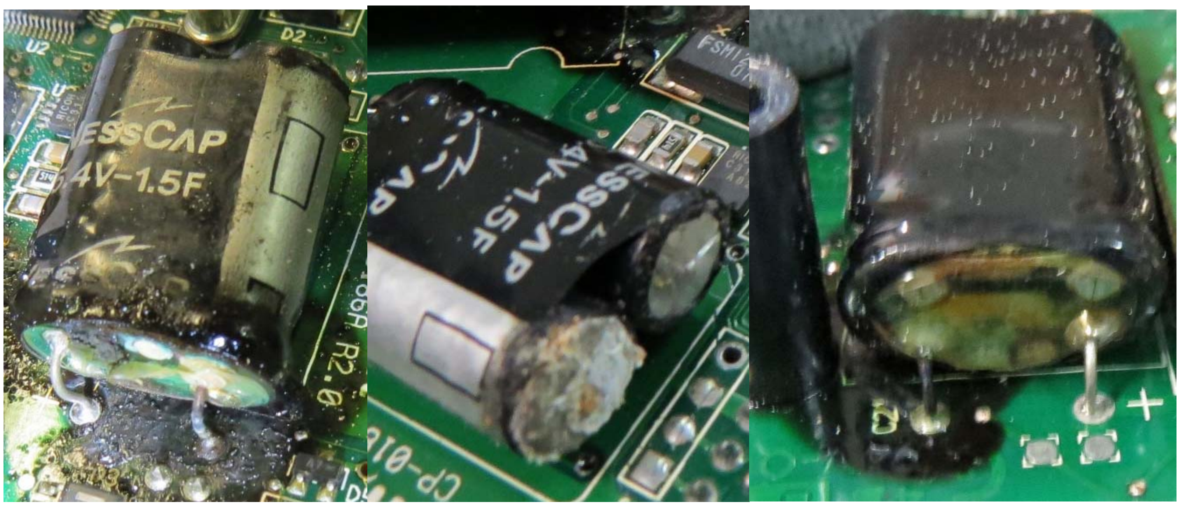


Figure 41. C7 in J2076164, C7 in J2200102 and C21 in J2200748

		Capacity (F)					
		2020-03-09	2020-03-13	2020-03-19	2020-03-24	2020-05-20	2020-05-26
1	J2050162	1,23	0,86	0,54	0,24	0,51	0,40
2	J2076164	1,23	1,07	0,90	0,56	0,53	0,30
3	J2176865	1,41	1,08	0,91	0,72	0,61	0,49
4	J2180811	1,31	0,92	0,71	0,83	0,71	0,67
5	J2200102	1,25	1,17	1,08	1,16	1,04	1,01
6	J2220748	1,22	0,01	0,12	0,12	0,15	0,15
7	J2239994	1,20	0,86	0,61	0,59	0,63	0,46
8	J2261741	1,45	1,31	1,18	1,25	0,57	0,30
9	J2552045	1,23	0,98	0,67	0,68	0,50	0,35
10	J2573558	1,33	1,27	1,22	1,29	0,91	0,55
11	J2597250	1,24	1,06	0,99	1,04	0,19	0,17
12	J2627943	1,35	1,23	0,91	0,58	0,15	0,15
13	J2695237	1,31	1,17	1,17	1,21	0,97	0,97
14	J2881406	1,33	1,17	1,09	1,12	0,51	0,29
15	J2890621	1,26	1,08	1,07	1,20	0,51	0,40
16	J2905935	1,25	1,08	0,64	0,35	0,48	0,42
17	J2965870	1,34	1,23	1,09	1,25	0,46	0,21
18	J2969318	1,40	1,19	1,06	1,11	0,72	0,36
19	J2970555	1,33	1,03	0,70	0,78	0,66	0,47

Table 37. Capacitance of capacitor C21 and C35

While communication problems were only observed in six meters, it is noteworthy that in 17 of the 19 meters, capacitor C21 was at end-of-life. According to the technical specifications published by the manufacturer of the capacitors, NessCap, end-of-life is when capacitance has dropped by 30% and series resistance by 50% of their rated values.

Table 37 shows the capacitance values measured at different times during testing. Cells with red text indicate the meter had stopped communicating. Cells highlighted in yellow show the capacitors that had reached the end-of-life criterion (<0.95 F).

7.3.1.2 GEN3—J1 issue

Of the 11 GEN3 meters tested, only one experienced a communication problem caused by cracked solder on connector J1.

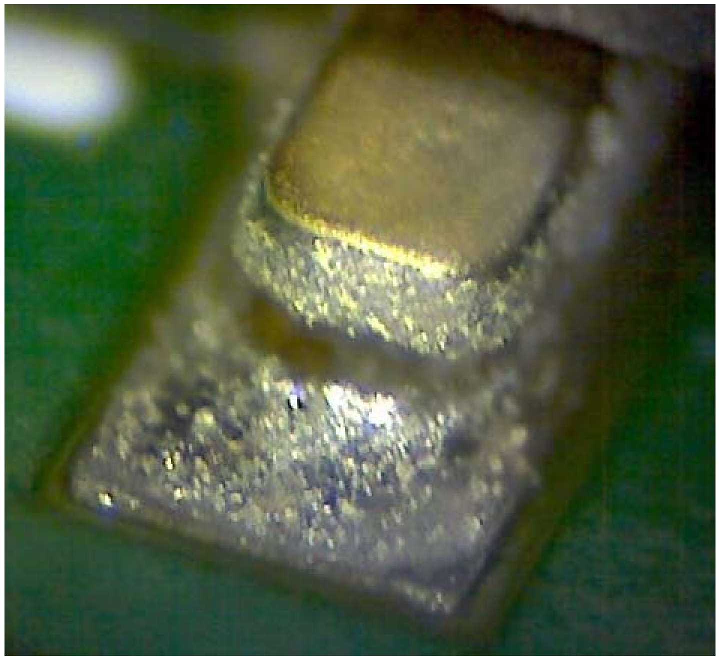


Figure 42. Cracked solder on connector J1

7.3.2 Power problem

Only one meter had a transformer problem: meter #27, J3781647, Focus GEN3. The faulty transformer was made by Zettler Magnetics. Previous observations had shown no failures connected with this manufacturer. Since there was only one failure of this type, it is impossible to extrapolate on the remaining service life in this failure mode.

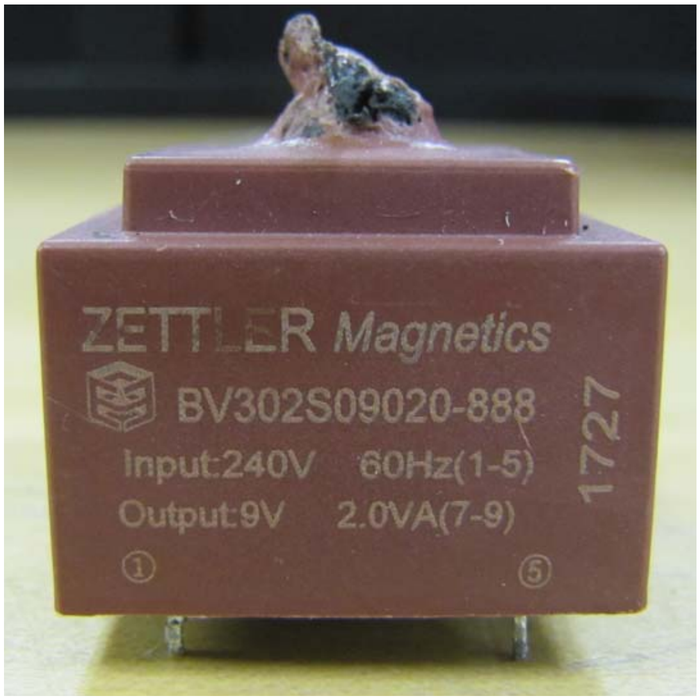


Figure 43. Failed Zettler transformer

7.3.3 LCD

7.3.3.1 Screen darkening

The LCDs on all GEN1 meters became darker, as shown in Figure 44. In comparison, the screens on GEN3 meters remained legible under the same conditions. This failure was unexpected, since Hydro One had never observed it in the field. It is possible that the test conditions exceeded the operating conditions of the LCDs. It should be noted that the life constraints were selected based on the technical specifications published by the meter manufacturer. Therefore, the test parameters did not exceed the equipment's operating conditions.

Figure 44. LCDs in GEN 1 meters

Based on our observations, the darkening was mainly caused by the degradation of the polarizing film on the screen, which even detached in some cases, as shown in Figure 45.

Figure 45. Detached and darkened top polarizing filter

Figure 46. LCDs in GEN3 meters

	Contrast					
	2020-03-09	2020-03-13	2020-03-19	2020-03-24	2020-05-20	2020-05-26
J2050162	17,5%	14,0%	2,7%	1,5%	0,6%	0,2%
J2076164	18,1%	13,0%	2,6%	0,9%	0,3%	0,3%
J2176865	18,1%	16,3%	2,3%	0,9%	0,5%	0,5%
J2180811	19,1%	18,5%	18,4%	1,4%	0,6%	0,8%
J2200102	18,5%	18,5%	18,3%	17,6%	0,1%	1,3%
J2220748	17,9%	17,5%	16,6%	0,9%	0,7%	0,8%
J2239994	0,1%	18,6%	17,6%	1,6%	0,9%	3,2%
J2261741	18,8%	18,3%	18,0%	0,9%	0,9%	0,9%
J2552045	17,5%	18,1%	17,0%	17,5%	6,6%	1,1%
J2573558	17,5%	17,8%	16,2%	2,4%	0,6%	0,5%
J2597250	16,4%	15,5%	5,1%	1,5%	0,3%	0,3%
J2627943	17,0%	15,6%	2,1%	0,4%	0,4%	0,8%
J2695237	16,2%	15,6%	4,2%	1,3%	0,3%	2,3%
J2881406	16,8%	16,7%	16,5%	16,0%	4,5%	2,0%
J2890621	17,3%	17,1%	17,5%	17,4%	17,5%	2,7%
J2905935	16,3%	16,2%	16,3%	16,0%	2,4%	1,5%
J2965870	17,0%	16,8%	16,6%	15,9%	9,7%	1,3%
J2969318	16,2%	16,5%	16,3%	16,4%	16,9%	1,4%
J2970555	15,3%	15,4%	16,1%	15,6%	15,5%	2,0%
J3325552	18,7%	17,7%	17,3%	17,2%	16,9%	3,6%
J3366877	17,3%	17,0%	17,8%	4,6%	0,6%	0,9%
J3420986	15,6%	16,2%	16,1%	15,5%	12,7%	5,5%
J3516091	17,0%	17,1%	17,2%	17,1%	16,6%	13,9%
J3616484	15,6%	16,8%	16,3%	15,4%	15,7%	14,0%
J3686949	15,7%	16,5%	15,4%	15,7%	16,7%	15,8%
J3742833	15,7%	15,9%	16,4%	16,3%	16,5%	17,5%
J3781647	15,8%	17,0%	17,0%	15,9%	16,1%	10,1%
J3805040	14,9%	15,6%	15,6%	15,4%	15,7%	15,7%
J3825926	15,4%	16,3%	16,6%	15,9%	15,9%	13,8%
J3825942	14,9%	15,9%	16,1%	15,6%	16,5%	15,4%

Table 38. LCD contrast during damp heat testing

Table 38 shows contrast measurements taken with the colorimeter. As discussed in Section 5.6.1, the minimum contrast for the LCD to be considered legible is 2.5%. Cells highlighted in red show readings under that threshold.

7.3.3.2 Missing segment

In addition to problems of darkening screens on GEN1 meters, two meters had LCD segments disappear. We observed this problem on two of the 19 GEN1 meters tested. We should note, however, that the darkening of GEN1 screens could have hidden disappearing segments. Consequently, we have some reservations about this result.

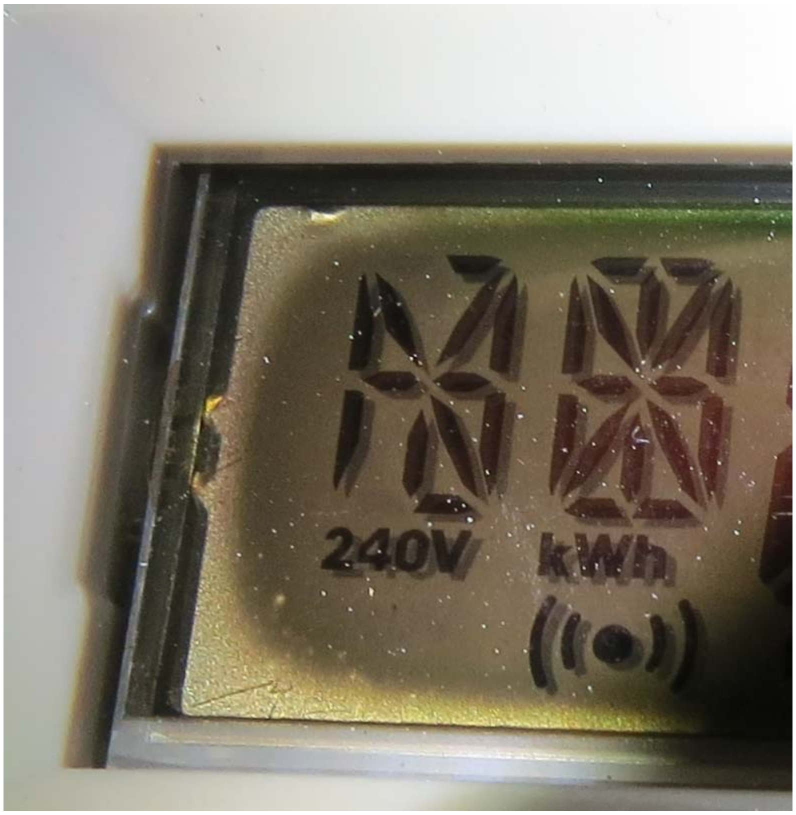


Figure 47. Meter J2970555 with missing segments

Figure 48. Meter J2965870 with missing segments

8 Weibull distributions

Parameters were calculated using the equations from IEC 62059-31-1 Section 6.3. The explanations below and the equations are taken from that standard.

To obtain a linear representation, the Weibull reliability function must first be transformed into linear form. From the reliability function:

$$F(t) = 1 - e^{-\left(\frac{t}{\eta}\right)^{\beta}}$$

We obtain:

$$y = A + Bx$$

With:

$$y = ln\{-\ln(1 - F(t))\}$$
$$A = -\beta \ln(\eta)$$
$$B = \beta$$
$$x = \ln(t)$$

This equation shows that the reliability function should be linear if it is plotted on Weibull probability paper, with which the unreliability is plotted on a log-log scale in relation to t. To facilitate reading the distributions, the preferred representation in this report is a log scale on the time axis and a non-log scale on the y axis.

8.1 Input data to be used

When analyzing life data from an accelerated reliability test, it is necessary to include data on the items that have failed, but also data on the items that have not failed. Data on items that have not failed are referred to as censored data (see IEC 60300-3-5, 8.3).

When the times to failure of all the items under test are observed, the data are said to be complete. In that case, the data logged during the test are all the times to failure of the items. If, however, items remain non-failed at the end of the test, then the observations are said to be censored: when the test is terminated after a time t, then for those items that have not failed the data are said to be time censored.

For some checks carried out once a week during test stoppages, the time to failure must be adjusted, as specified in IEC 62059-31-1 Section 6.3.1.

The following equation is used:

$$(n \text{ x } IT) - (p\, x \cdot IT/(p+1)),$$
$$(n\, x \cdot IT) - ((p-1) \cdot IT/(p+1)),$$
$$\ldots(n\, x \cdot IT) - (2 \cdot IT/(p+1)),\ (n \cdot IT) - (IT/(p+1)).$$

n is the nth interval of time

p is the number of failure detected (not suspended)

IT is the interval of time between each observations

8.2 Ranking of the time to failure

Since no equipment was censored before the end of the test, ranking did not have to be adjusted. See IEC 62059-31-1 Section 6.3.2 for more information on the equations to use to adjust ranking.

8.3 Reliability/unreliability estimates

The next step is to estimate the unreliability corresponding to each time to failure by calculating the corresponding median rank.

The Median Rank noted U50i (unreliability at the ith failure with a confidence level of 50 %) is the true probability of failure F(ti) or unreliability estimate at the ith failure on a sample of N items with a confidence level of 50 %. In other words, U50i is the estimate of the cumulative fraction of items that will fail at time TTFi, where TTFi is the time to failure of the ith failure.

This value is obtained by solving the cumulative binomial distribution for X:

$$CL = \sum_{j=i}^{N} C_j^N X^j (1 - X)^{N-j}$$

Where *CL* is the confidence level (0 < *CL* < 1), *N* is the sample size, and *j* is the order number (or adjusted rank).For median rank, *CL* = 0.5. In other words, *CL* = 0.5 means that half the population makes more (or less) than the median rank.

Rank tables are available in Annex D of 62059-31-1, also the function BETA.INV in excel calculates the same values. The following tables were used.

N= 19

	5%	50%	95%
1	0,0027	0,0358	0,1459
2	0,0190	0,0868	0,2264
3	0,0445	0,1383	0,2958
4	0,0753	0,1899	0,3594
5	0,1099	0,2415	0,4191
6	0,1475	0,2932	0,4758
7	0,1875	0,3449	0,5300
8	0,2297	0,3966	0,5819
9	0,2739	0,4483	0,6319
10	0,3201	0,5000	0,6799
11	0,3681	0,5517	0,7261
12	0,4181	0,6034	0,7703
13	0,4700	0,6551	0,8125
14	0,5242	0,7068	0,8525
15	0,5809	0,7585	0,8901
16	0,6406	0,8101	0,9247
17	0,7042	0,8617	0,9555
18	0,7736	0,9132	0,9810
19	0,8541	0,9642	0,9973

N= 11

	5%	50%	95%
1	0,0047	0,0611	0,2384
2	0,0333	0,1480	0,3644
3	0,0788	0,2358	0,4701
4	0,1351	0,3238	0,5644
5	0,1996	0,4119	0,6502
6	0,2712	0,5000	0,7288
7	0,3498	0,5881	0,8004
8	0,4356	0,6762	0,8649
9	0,5299	0,7642	0,9212
10	0,6356	0,8520	0,9667
11	0,7616	0,9389	0,9953

Table 39. Reliability estimate for sample size N=19 and N=11

8.4 Calculation of parameters

Once times to failure have been ranked, and reliability/unreliability has been estimated for each time to failure, all data are ready to construct the graphical representation and to calculate the parameters of the distribution.

Parameters *A* and *B* of the equation $y = A + Bx$ can be estimated by performing a least squares/rank regression on *yi* and *xi* data, where:

$$x_i = \ln(TTFi)$$

$$y_i = \ln(-\ln(1 - F(TTFi)))$$

According to the least squares/rank regression principle, which minimizes the vertical distance between the data points and the straight line fitted to the data, the best fitting straight line to these data is the straight line $y = A + Bx$ such that *F* is minimum, where

$$F = \sum_{i=1}^{p} (A + Bx_i - y_i)^2$$

and *p* is the number of items which failed during the test.

By solving the equations $\frac{dF}{dA} = 0$ and $\frac{dF}{dB} = 0$, we obtain:

Estimation of B:

$$B = \frac{\sum_{i=1}^{p} x_i y_i - \frac{\sum_{i=1}^{N} x_i \sum_{i=1}^{N} y_i}{p}}{\sum_{i=1}^{p} x_i^2 - \frac{\left(\sum_{i=1}^{p} x_i\right)^2}{p}}$$

Estimation of A:

$$A = \frac{\sum_{i=1}^{p} y_i}{p} - B\frac{\sum_{i=1}^{p} x_i}{p}$$

Estimation of the coefficient of determination R^2

$$R^2 = \frac{\left(\sum_{i=1}^{p} x_i y_i - \frac{\sum_{i=1}^{p} x_i \sum_{i=1}^{p} y_i}{p}\right)^2}{\left(\sum_{i=1}^{p} x_i^2 - \frac{\left(\sum_{i=1}^{p} x_i\right)^2}{p}\right)\left(\sum_{i=1}^{p} y_i^2 - \frac{\left(\sum_{i=1}^{p} y_i\right)^2}{p}\right)}$$

R^2 gives an indication on the quality of the rank regression.

The goodness of fit test consists in verifying that R^2 is higher or equal to the acceptance threshold, AccThr.

According to 62059-31-1, the acceptance threshold depends on the number of failures detected (p). For a two-parameter distribution:

$$AccThr = (1 - e^{-\left(\frac{p}{0.399}\right)^{0.177}})^2$$

p	AccThr
4	0,80226973
5	0,81861607
6	0,83145599
7	0,84193414
8	0,85072228
9	0,85824669
10	0,86479394
11	0,87056539
12	0,87570763
13	0,88033044
14	0,88451805
15	0,88833637
16	0,8918379
17	0,89506507
18	0,89805263
19	0,90082936

Table 40. Acceptance threshold by number of failures

The coefficient of determination must therefore be found to exceed the AccThr threshold for each curve.

8.5 Results

8.5.1 HTOL

8.5.1.1 Communication

Figure 49 shows the Weibull distribution for the communication failures observed during the HTOL test. The green curve represents the observed data, and the blue (U50%), red (U5%) and purple (U95%) curves represent the reliability curves with confidence levels of 50%, 5% and 95%, respectively.

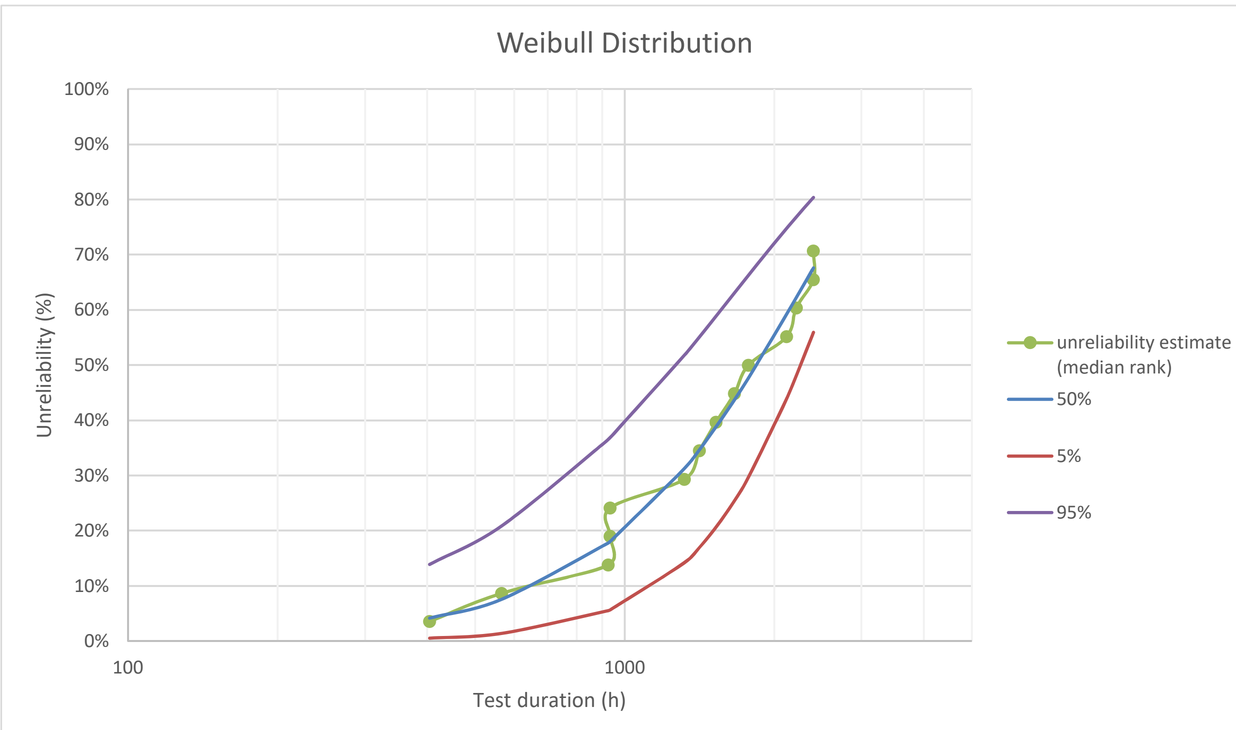


Figure 49. Weibull curves for communication failure in HTOL

The data used to produce Figure 49 are shown in Tables 41, 42 and 43.

The coefficients of determination of the three curves respect the AccThr criterion of 0.8845 for p=14.

Rank	failure time	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) (50%)
1	405	405	19	4%	6,004	-3,311	4,18%
2	565	565	18	9%	6,337	-2,399	7,58%
3	927	927	17	14%	6,832	-1,905	17,80%
4	935	935	16	19%	6,841	-1,558	18,06%
5	935	935	15	24%	6,841	-1,286	18,06%
6	1319	1319	14	29%	7,185	-1,058	31,28%
7	1415	1415	13	34%	7,255	-0,860	34,74%
8	1527	1527	12	40%	7,331	-0,683	38,80%
9	1663	1663	11	45%	7,416	-0,520	43,70%
10	1775	1775	10	50%	7,482	-0,367	47,67%
11	2119	2119	9	55%	7,659	-0,220	59,23%
12	2215	2215	8	60%	7,703	-0,078	62,22%
13	2399	2399	7	66%	7,783	0,062	67,61%
14	2399	2399	6	71%	7,783	0,204	67,61%
15	suspended	suspended					
16	suspended	suspended					
17	suspended	suspended					
18	suspended	suspended					
19	suspended	suspended					

N	19
p	14
B	1,840
A	-14,200
R2	0,980

50%	
Gamma	0
Beta	1,840
Eta	2247,621

Table 41. Communication failure in HTOL – Weibull distribution with confidence level of 50%

Rank	failure time corrected	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) 5%
1	405	405	19	0%	6,004	-5,915	0,56%
2	565	565	18	2%	6,337	-3,952	1,41%
3	927	927	17	4%	6,832	-3,090	5,54%
4	935	935	16	8%	6,841	-2,547	5,67%
5	935	935	15	11%	6,841	-2,150	5,67%
6	1319	1319	14	15%	7,185	-1,835	14,21%
7	1415	1415	13	19%	7,255	-1,572	17,02%
8	1527	1527	12	23%	7,331	-1,343	20,63%
9	1663	1663	11	27%	7,416	-1,139	25,43%
10	1775	1775	10	32%	7,482	-0,952	29,69%
11	2119	2119	9	37%	7,659	-0,779	43,94%
12	2215	2215	8	42%	7,703	-0,614	48,07%
13	2399	2399	7	47%	7,783	-0,454	55,94%
14	2399	2399	6	52%	7,783	-0,297	55,94%
15	suspended	suspended					
16	suspended	suspended					
17	suspended	suspended					
18	suspended	suspended					
19	suspended	suspended					

N	19
p	14
B	2,803
A	-22,016
R2	0,954

5%	
Gamma	0
Beta	2,803
Eta	2575,543

Table 42. Communication failure in HTOL – Weibull distribution with confidence level of 5%

Rank	failure time corrected	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) 95%
1	405	405	19	15%	6,004	-1,847	13,90%
2	565	565	18	23%	6,337	-1,360	20,86%
3	927	927	17	30%	6,832	-1,048	36,54%
4	935	935	16	36%	6,841	-0,809	36,87%
5	935	935	15	42%	6,841	-0,610	36,87%
6	1319	1319	14	48%	7,185	-0,437	51,80%
7	1415	1415	13	53%	7,255	-0,281	55,15%
8	1527	1527	12	58%	7,331	-0,137	58,86%
9	1663	1663	11	63%	7,416	-0,001	63,06%
10	1775	1775	10	68%	7,482	0,130	66,28%
11	2119	2119	9	73%	7,659	0,258	74,81%
12	2215	2215	8	77%	7,703	0,386	76,85%
13	2399	2399	7	81%	7,783	0,515	80,37%
14	2399	2399	6	85%	7,783	0,649	80,37%
15	suspended	suspended					
16	suspended	suspended					
17	suspended	suspended					
18	suspended	suspended					
19	suspended	suspended					

N	19
p	14
B	1,342
A	-9,954
R2	0,978

95%	
Gamma	0
Beta	1,342
Eta	1668,015

Table 43. Communication failure in HTOL – Weibull distribution with confidence level of 95%

8.5.1.2 Capacitors

Figure 50 shows the Weibull distribution for the capacitor failures observed during the HTOL test. The green curve represents the observed data, and the blue (U50%), red (U5%) and purple (U95%) curves represent the reliability curves with confidence levels of 50%, 5% and 95%, respectively.

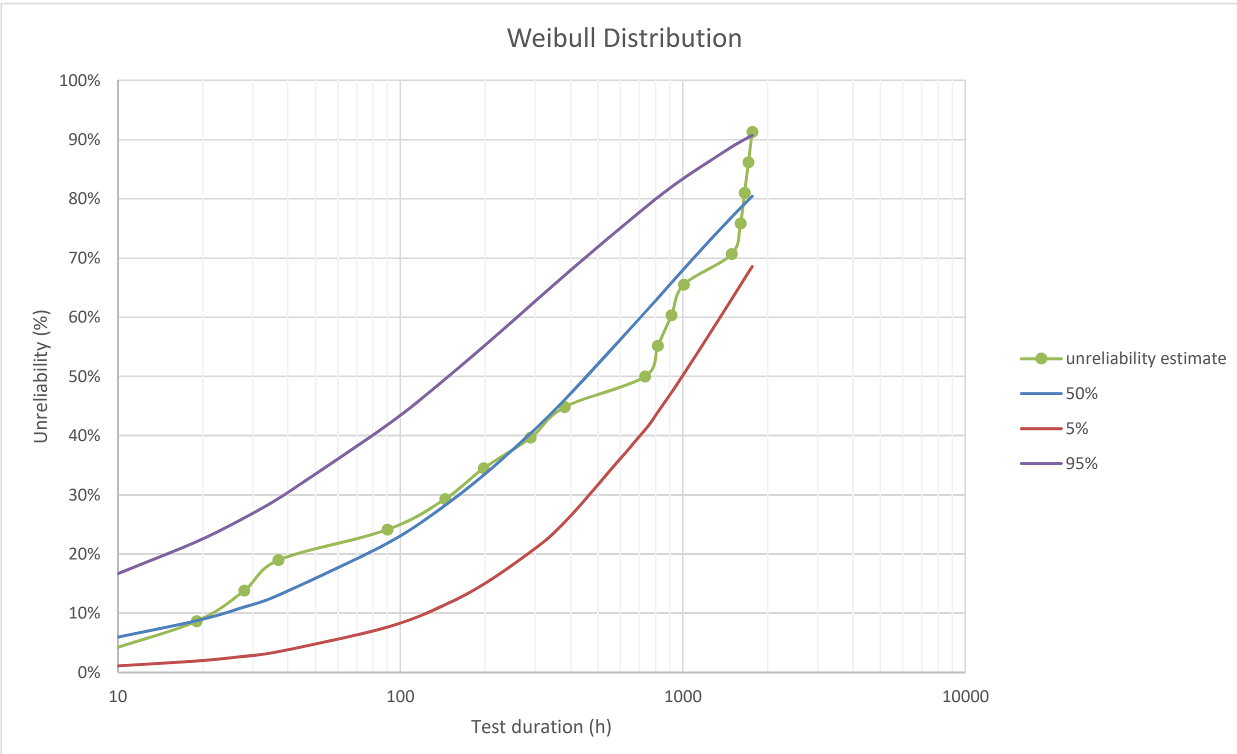


Figure 50. Weibull curves for capacitor failures in HTOL

The data used to produce Figure 50 are shown in Tables 44, 45 and 46.

The coefficients of determination of the three curves respect the AccThr criterion of 0.8981 for p=18.

Rank	failure time	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) (50%)
1	37	9	19	4%	2,197	-3,311	5,5%
2	37	19	18	9%	2,944	-2,399	8,8%
3	37	28	17	14%	3,332	-1,905	11,1%
4	37	37	16	19%	3,611	-1,558	13,1%
5	197	90	15	24%	4,500	-1,286	21,8%
6	197	144	14	29%	4,970	-1,058	28,3%
7	197	197	13	34%	5,283	-0,860	33,3%
8	381	289	12	40%	5,666	-0,683	40,4%
9	381	381	11	45%	5,943	-0,520	46,0%
10	815	734	10	50%	6,599	-0,367	60,8%
11	815	815	9	55%	6,703	-0,220	63,2%
12	1007	911	8	60%	6,815	-0,078	65,8%
13	1007	1007	7	66%	6,915	0,062	68,2%
14	1487	1487	6	71%	7,305	0,204	76,9%
15	1599	1599	5	76%	7,377	0,351	78,5%
16	1759	1652	4	81%	7,410	0,508	79,2%
17	1759	1706	3	86%	7,442	0,682	79,8%
18	1759	1759	2	91%	7,473	0,894	80,5%
19	suspended		1	96%			

N	19
p	18
B	0,636
A	-4,262
R2	0,960

50%	
Gamma	0
Beta	0,636
Eta	814,052

Table 44. Capacitor failure in HTOL – Weibull distribution with confidence level of 50%

Rank	failure time corrected	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) 5%
1	37	9	19	0%	2,197	-5,915	1,0%
2	37	19	18	2%	2,944	-3,952	2,0%
3	37	28	17	4%	3,332	-3,090	2,8%
4	37	37	16	8%	3,611	-2,547	3,5%
5	197	90	15	11%	4,500	-2,150	7,7%
6	197	144	14	15%	4,970	-1,835	11,5%
7	197	197	13	19%	5,283	-1,572	14,9%
8	381	289	12	23%	5,666	-1,343	20,4%
9	381	381	11	27%	5,943	-1,139	25,4%
10	815	734	10	32%	6,599	-0,952	41,0%
11	815	815	9	37%	6,703	-0,779	44,0%
12	1007	911	8	42%	6,815	-0,614	47,3%
13	1007	1007	7	47%	6,915	-0,454	50,4%
14	1487	1487	6	52%	7,305	-0,297	63,0%
15	1599	1599	5	58%	7,377	-0,140	65,4%
16	1759	1652	4	64%	7,410	0,023	66,5%
17	1759	1706	3	70%	7,442	0,197	67,6%
18	1759	1759	2	77%	7,473	0,396	68,6%
19	suspended	suspended	1	85%			

N	19
p	18
B	0,899
A	-6,575
R2	0,927

5%	
Gamma	0
Beta	0,899
Eta	1494,654

Table 45. Capacitor failure in HTOL – Weibull distribution with confidence level of 5%

Rank	failure time corrected	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) 95%
1	37	9	19	15%	2,197	-1,847	15,8%
2	37	19	18	23%	2,944	-1,360	22,1%
3	37	28	17	30%	3,332	-1,048	26,1%
4	37	37	16	36%	3,611	-0,809	29,4%
5	197	90	15	42%	4,500	-0,610	41,8%
6	197	144	14	48%	4,970	-0,437	49,6%
7	197	197	13	53%	5,283	-0,281	55,1%
8	381	289	12	58%	5,666	-0,137	62,0%
9	381	381	11	63%	5,943	-0,001	67,1%
10	815	734	10	68%	6,599	0,130	78,6%
11	815	815	9	73%	6,703	0,258	80,3%
12	1007	911	8	77%	6,815	0,386	82,0%
13	1007	1007	7	81%	6,915	0,515	83,5%
14	1487	1487	6	85%	7,305	0,649	88,8%
15	1599	1599	5	89%	7,377	0,792	89,7%
16	1759	1652	4	92%	7,410	0,950	90,0%
17	1759	1706	3	96%	7,442	1,136	90,4%
18	1759	1759	2	98%	7,473	1,377	90,7%
19	suspended	suspended	1	100%			

N	19
p	18
B	0,498
A	-2,852
R2	0,950

95%	
Gamma	0
Beta	0,498
Eta	308,300

Table 46. Capacitor failure in HTOL – Weibull distribution with confidence level of 95%

8.5.2 Thermal cycles

The thermal cycle test did not produce enough failures to generate Weibull curves.

8.5.3 Damp heat

Figure 51 shows the Weibull distribution for the liquid crystal display failures observed during the damp heat test. The green curve represents the observed data. The blue (U50%), red (U5%) and purple (U95%) curves represent the reliability curves with confidence levels of 50%, 5% and 95%, respectively.

8.5.3.1 LCD failure

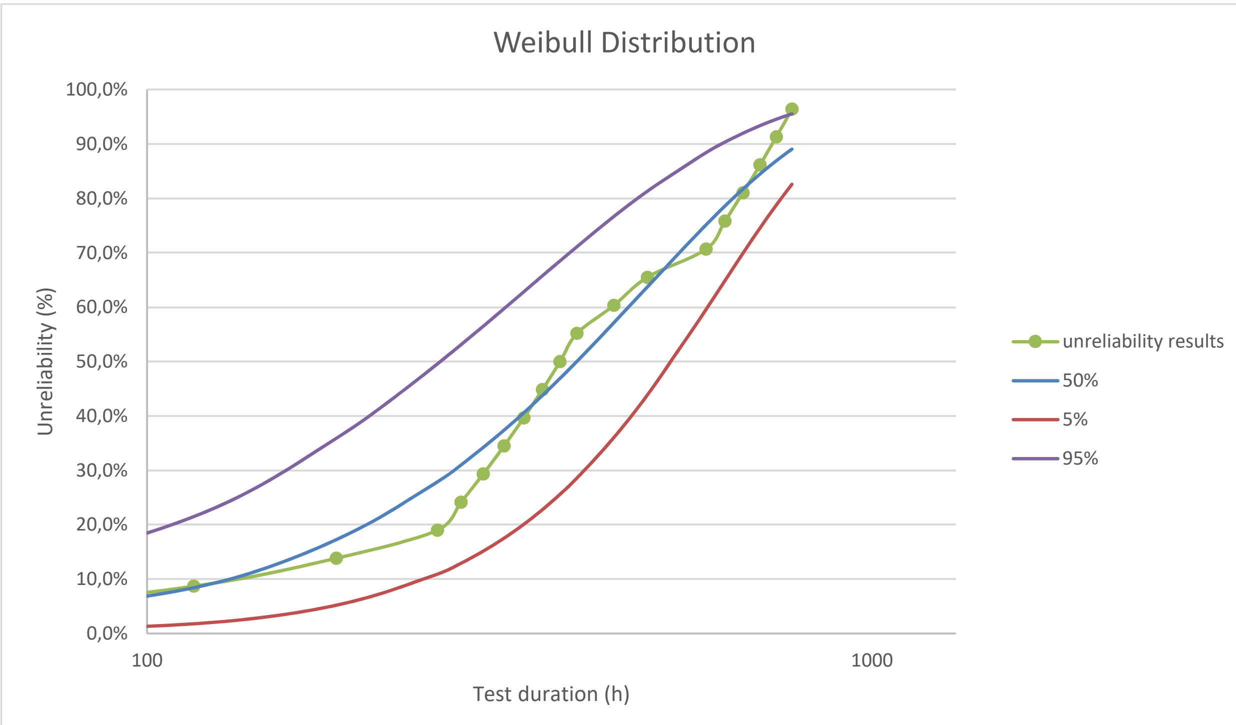


Figure 51. Weibull curves for LCD failure in damp heat

The data used to produce Figure 51 are shown in Tables 47, 48 and 49.

The coefficients of determination of the three curves respect the AccThr criterion of 0.9001 for p=19.

RANK	failure time	reverse rank	unreliability results	xi	yi	f(t) 50%
1	57	19	3,6%	4,045	-3,311	2,3%
2	114	18	8,7%	4,738	-2,399	8,4%
3	171	17	13,8%	5,144	-1,905	17,2%
4	229	16	19,0%	5,432	-1,558	27,9%
5	244	15	24,2%	5,499	-1,286	31,0%
6	260	14	29,3%	5,562	-1,058	34,2%
7	276	13	34,5%	5,621	-0,860	37,4%
8	292	12	39,7%	5,677	-0,683	40,6%
9	308	11	44,8%	5,731	-0,520	43,8%
10	324	10	50,0%	5,781	-0,367	46,9%
11	340	9	55,2%	5,829	-0,220	50,0%
12	378	8	60,3%	5,934	-0,078	57,1%
13	416	7	65,5%	6,029	0,062	63,8%
14	491	6	70,7%	6,196	0,204	75,2%
15	518	5	75,8%	6,250	0,351	78,6%
16	545	4	81,0%	6,302	0,508	81,7%
17	573	3	86,2%	6,350	0,682	84,5%
18	600	2	91,3%	6,397	0,894	86,9%
19	627	1	96,4%	6,441	1,203	89,1%

p	19
B	1,896
A	-11,4
R2	0,966

50%	
Gamma	0
Beta	1,896
Eta	412,3

Table 47. LCD failure in damp heat – Weibull distribution with confidence level of 50%

RANK	failure time	reverse rank	unreliability estimate	xi	yi	f(t) 5%
1	57	19	0%	4,045	-5,915	0,3%
2	114	18	2%	4,738	-3,952	1,8%
3	171	17	4%	5,144	-3,090	5,2%
4	229	16	8%	5,432	-2,547	10,9%
5	244	15	11%	5,499	-2,150	12,9%
6	260	14	15%	5,562	-1,835	15,1%
7	276	13	19%	5,621	-1,572	17,5%
8	292	12	23%	5,677	-1,343	20,1%
9	308	11	27%	5,731	-1,139	22,8%
10	324	10	32%	5,781	-0,952	25,6%
11	340	9	37%	5,829	-0,779	28,6%
12	378	8	42%	5,934	-0,614	36,0%
13	416	7	47%	6,029	-0,454	43,9%
14	491	6	52%	6,196	-0,297	59,6%
15	518	5	58%	6,250	-0,140	64,9%
16	545	4	64%	6,302	0,023	69,9%
17	573	3	70%	6,350	0,197	74,6%
18	600	2	77%	6,397	0,396	78,8%
19	627	1	85%	6,441	0,655	82,6%

p	19
B	2,693
A	-16,8
R2	0,987

5%	
Gamma	0
Beta	2,693
Eta	509,4

Table 48. LCD failure in damp heat – Weibull distribution with confidence level of 5%

RANK	failure time	reverse rank	unreliability estimate	xi	yi	f(t) 95%
1	57	19	15%	4,045	-1,847	8%
2	114	18	23%	4,738	-1,360	21%
3	171	17	30%	5,144	-1,048	36%
4	229	16	36%	5,432	-0,809	50%
5	244	15	42%	5,499	-0,610	53%
6	260	14	48%	5,562	-0,437	57%
7	276	13	53%	5,621	-0,281	60%
8	292	12	58%	5,677	-0,137	63%
9	308	11	63%	5,731	-0,001	66%
10	324	10	68%	5,781	0,130	69%
11	340	9	73%	5,829	0,258	71%
12	378	8	77%	5,934	0,386	77%
13	416	7	81%	6,029	0,515	81%
14	491	6	85%	6,196	0,649	88%
15	518	5	89%	6,250	0,792	90%
16	545	4	92%	6,302	0,950	92%
17	573	3	96%	6,350	1,136	93%
18	600	2	98%	6,397	1,377	95%
19	627	1	100%	6,441	1,778	96%

p	19
B	1,501
A	-8,53
R2	0,915

5%	
Gamma	0
Beta	1,501
Eta	294,2
R2	0,965

Table 49. LCD failure in damp heat – Weibull distribution with confidence level of 95%

8.5.3.2 Capacitors

Figure 52 shows the Weibull distribution for the capacitor failures observed during the damp heat test. The green curve represents the observed data. The blue (U50%), red (U5%) and purple (U95%) curves represent the reliability curves with confidence levels of 50%, 5% and 95%, respectively.

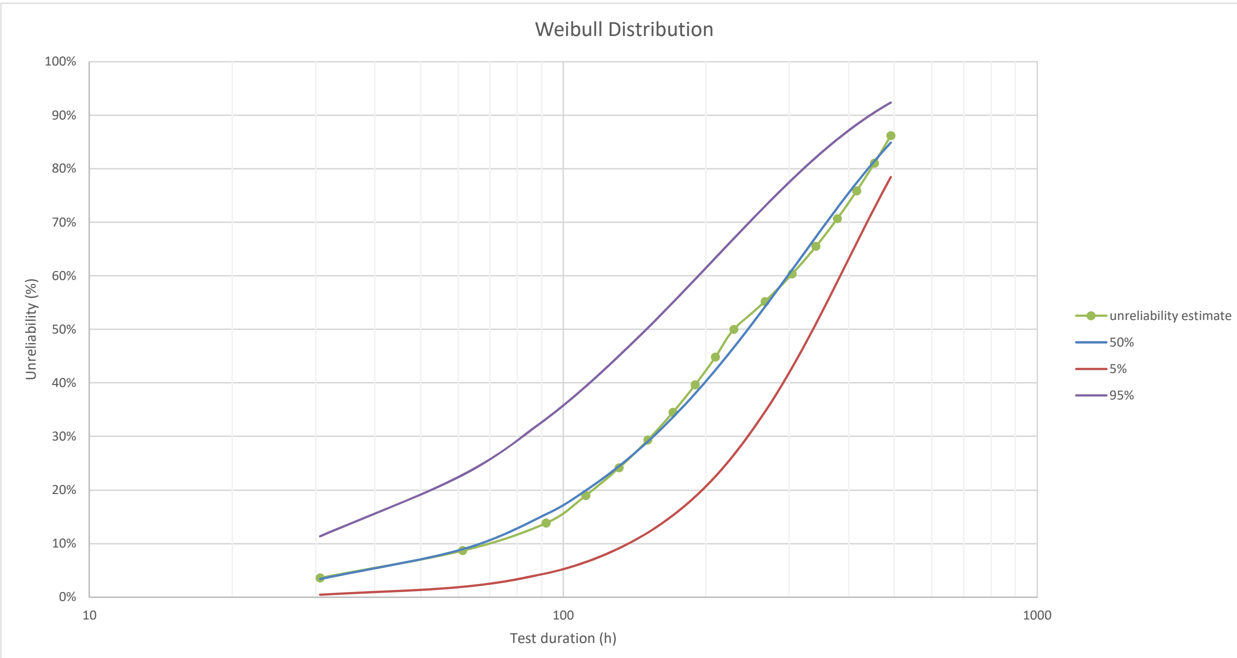


Figure 52. Weibull curves for capacitor failures in Damp Heat

The data used to produce Figure 52 are shown in Tables 50, 51 and 52.

The coefficients of determination of the three curves respect the AccThr criterion of 0.8951 for p=17.

Rank	failure time	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) (50%)
1	92	31	19	4%	3,423	-3,311	3,4%
2	92	61	18	9%	4,116	-2,399	8,9%
3	92	92	17	14%	4,522	-1,905	15,5%
4	84	112	16	19%	4,715	-1,558	19,9%
5	236	131	15	24%	4,876	-1,286	24,5%
6	236	151	14	29%	5,015	-1,058	29,0%
7	236	170	13	34%	5,137	-0,860	33,6%
8	236	190	12	40%	5,246	-0,683	38,0%
9	236	209	11	45%	5,344	-0,520	42,4%
10	236	229	10	50%	5,434	-0,367	46,6%
11	516	266	9	55%	5,585	-0,220	54,2%
12	516	304	8	60%	5,717	-0,078	61,1%
13	516	341	7	66%	5,833	0,062	67,3%
14	516	379	6	71%	5,937	0,204	72,7%
15	516	416	5	76%	6,031	0,351	77,4%
16	516	454	4	81%	6,117	0,508	81,4%
17	516	491	3	86%	6,196	0,682	84,9%
18	suspended	600	2	91%			
19	suspended	700	1	96%			

N	19
p	17
B	1,444
A	-8,313
R2	0,997

50%	
Gamma	0
Beta	1,444
Eta	316,179

Table 50. Capacitor failure in damp heat – Weibull distribution with confidence level of 50%

Rank	failure time	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) 5%
1	92	31	19	0%	3,423	-5,915	0,4%
2	92	61	18	2%	4,116	-3,952	1,9%
3	92	92	17	4%	4,522	-3,090	4,4%
4	84	112	16	8%	4,715	-2,547	6,6%
5	236	131	15	11%	4,876	-2,150	9,1%
6	236	151	14	15%	5,015	-1,835	12,0%
7	236	170	13	19%	5,137	-1,572	15,3%
8	236	190	12	23%	5,246	-1,343	18,8%
9	236	209	11	27%	5,344	-1,139	22,6%
10	236	229	10	32%	5,434	-0,952	26,6%
11	516	266	9	37%	5,585	-0,779	34,6%
12	516	304	8	42%	5,717	-0,614	42,8%
13	516	341	7	47%	5,833	-0,454	51,0%
14	516	379	6	52%	5,937	-0,297	58,9%
15	516	416	5	58%	6,031	-0,140	66,2%
16	516	454	4	64%	6,117	0,023	72,7%
17	516	491	3	70%	6,196	0,197	78,4%
18	suspended	600	2	77%			
19	suspended	700	1	85%			

N	19
p	17
B	2,102
A	-12,599
R2	0,981

5%	
Gamma	0
Beta	2,102
Eta	400,561

Table 51. Capacitor failure in damp heat – Weibull distribution with confidence level of 5%

Rank	failure time	adjusted failure time	reverse rank	unreliability estimate	xi	yi	f(t) 95%
1	92	31	19	15%	3,423	-1,847	11,4%
2	92	61	18	23%	4,116	-1,360	22,8%
3	92	92	17	30%	4,522	-1,048	33,3%
4	84	112	16	36%	4,715	-0,809	39,4%
5	236	131	15	42%	4,876	-0,610	45,1%
6	236	151	14	48%	5,015	-0,437	50,2%
7	236	170	13	53%	5,137	-0,281	55,0%
8	236	190	12	58%	5,246	-0,137	59,4%
9	236	209	11	63%	5,344	-0,001	63,3%
10	236	229	10	68%	5,434	0,130	67,0%
11	516	266	9	73%	5,585	0,258	73,0%
12	516	304	8	77%	5,717	0,386	78,0%
13	516	341	7	81%	5,833	0,515	82,1%
14	516	379	6	85%	5,937	0,649	85,5%
15	516	416	5	89%	6,031	0,792	88,2%
16	516	454	4	92%	6,117	0,950	90,5%
17	516	491	3	96%	6,196	1,136	92,3%
18	suspended	600	2	98%			
19	suspended	700	1	100%			

N	19
p	17
B	1,103
A	-5,894
R2	0,984

95%	
Gamma	0
Beta	1,103
Eta	208,727

Table 52. Capacitor failure in damp heat – Weibull distribution with confidence level of 95%

9 Conclusion

As part of the preliminary analysis, prior to the ALT, multiple meters in the sampled lots were already showing signs of electrolyte leaks in the area surrounding the capacitors. The accelerated life tests that were performed by Hydro-Quebec has shown clear indication of rapid degradation of those capacitors. For example at the end of HTOL test, 18 out of 19 C21 capacitors (GEN1) had reached their end of life based on manufacturer specifications. As capacitor failure become worse, it eventually leads to communication failure. Of the 19 GEN1 meters tested in HTOL, 14 stopped communicating. In all cases, the communication problem could be linked to the capacitors.

This study has provided acceleration factor and testing time to failure which are the two requirements to calculate expected remaining life.

Also something very important to note is that during all testing, meters remained within their accuracy class, and at no time were metering errors observed.

During all tests, Gen3 meters have performed better than GEN1 and no significant failures were noted for GEN3. We only make an exception for the Gen3 meters without the tripod which is more prone to suffering from the J1 issue. Only one sample of that variation of the GEN3 meters was tested and failed.

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AMI Benchmarking !

Prepared for: !

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December 16, 2020

Contents

Executive Summary ..... 3 !
1 Introduction ..... 4 !
1.1 Study Objectives ..... 4 !
1.2 Overview of Approach ..... 4 !
1.3 Content of Report ..... 4 !
2 Benchmarking Process ..... 5 !
2.1 Overview ..... 6 !
2.2 Information Collected ..... 7 !
2.3 Comparator Group Selection ..... 7 !
2.4 Normalizing Factors ..... 9 !
3 Benchmarking Observations ..... 9 !
3.1 Service Territory ..... 9 !
3.2 AMI Infrastructure ..... 10 !
3.3 AMI Replacements ..... 14 !
3.3.1 Meter Installation and Expected Service Life ..... 14 !
3.3.2 AMI Meter Replacement Rates ..... 16 !
3.3.3 Meter Technologies ..... 18 !
3.3.4 Labour Resources ..... 19 !
3.4 AMI Costs ..... 20 !

Executive Summary

The consortium of Guidehouse Canada Ltd. (Guidehouse) and First Quartile Consulting (1QC or First Quartile) has conducted a benchmarking study for Hydro One Networks Inc. (Hydro One or HONI) regarding Advanced Meter Infrastructure (AMI) meter replacement practices and costs.

This report provides an overview of the approach taken by Guidehouse and 1QC (including the processes of selecting and recruiting utilities to participate in the study, assembling appropriate performance metrics, and gathering / analysing the data) and results of the study, which provide insights into both the costs incurred by Hydro One and the practices used for the execution of AMI meter replacements. Primary findings from the study are highlighted below.

- Hydro One's service territory is the least dense as compared with the comparator group and includes a significant proportion of rural and remote areas that may be difficult or take longer to access.
- Hydro One and the majority of comparators have either completed or are in the process of completing the deployment of their AMI infrastructure, which consists of fixed 2-way RF meters that are read remotely, not manually.
- Hydro One currently uses smart meter functions similar to the comparators; Hydro One's future use cases also align with functions which comparators are seeking in their next generation AMI deployments.
- Hydro One has a greater percentage of AMI meters that were installed 10 or more years ago than the majority of comparators.
- As one of the early adopters of AMI meters, HONI is among 44% of respondents who have an expected service life of 15 years (some of these utilities were also early adopters of AMI), which represents the mode of the group;
- Hydro One's meter replacement rates over the past 5 years are below the mean. This is primarily a result of Hydro One performing individual replacements of older failed meters versus some comparator utilities performing mass new meter replacements. Hydro One is expecting to have the highest replacement rate in comparison to the others over the next five years -- this is attributable to a planned mass replacement program.
- Hydro One's labour resource type used to fix/replace meters aligns with most comparators, however the labour resource type used for communications equipment work differs from that of comparators due to its required use of bucket trucks for meter communication equipment that is mounted on poles.
- Hydro One's meter acquisition costs are higher than the mean of the comparator group, which contains a mixture of mass deployment and individual meter replacements - Hydro One's costs reflect individual replacements and do not include economies of scale that come with mass replacement programs
- Hydro One's meter installation labour costs are higher than the mean of the comparator group because Hydro One's current costs reflect individual replacements rather than mass replacements, and because of the large, mostly low-density nature of its service territory.

1 Introduction

1.1 Study Objectives

This study provides a comparative analysis of Hydro One's practices and unit costs for AMI meter replacement against a group of North American comparator utilities. In brief, the study was designed to:

- Quantify and evaluate Hydro One's unit replacement costs for AMI infrastructure;
- Benchmark those costs relative to a comparator group of utility organizations; and
- Evaluate Hydro One's related practices to provide a normalized assessment of the nature of Hydro One's AMI infrastructure relative to comparators.

1.2 Overview of Approach

In order to conduct the study, Guidehouse and First Quartile identified a representative group of comparator utilities and the relevant business and operational demographics that would be appropriate for comparisons.

This work leveraged the existing annual Transmission and Distribution benchmarking program conducted by First Quartile, with its underlying database of cost and demographic information, as well as additional activities that included reaching out to utilities that were not a part of that annual program.

The direct work of the study involved gathering the required demographic and operating data from Hydro One and the comparator utilities, and then normalizing that data to enable fair comparisons. Steps included in the study included the development of a series of graphs of relevant metrics, and then analysis of the various graphs and tables to draw conclusions about the results. To encourage participation, utilities who contributed data for the study were provided a copy of the charts and graphs, without the subsequent analysis.

1.3 Content of Report

The report is organized in the following sections:

Section 2: Benchmarking Process, which describes the benchmarking process used for comparator selection, data gathering, normalizing factors used, and analysis conducted.

Section 3: Benchmarking Observations, which summarizes the findings related to the overall demographics, replacement rates, and costs of AMI meter replacement.

2 Benchmarking Process

A benchmarking process is a way of comparing operating practices and results across a group of organizations. Formally, it is a means of gathering and analyzing data in a structured and standardized manner, suitable to evaluate business or operations performance and to uncover opportunities for improvement. Benchmarking provides an outputs-based assessment based on an understanding of the context of comparable organizations and operations. This understanding is important to enable normalization of findings in such a way that data, trends and findings can be understood and can lead to insights.

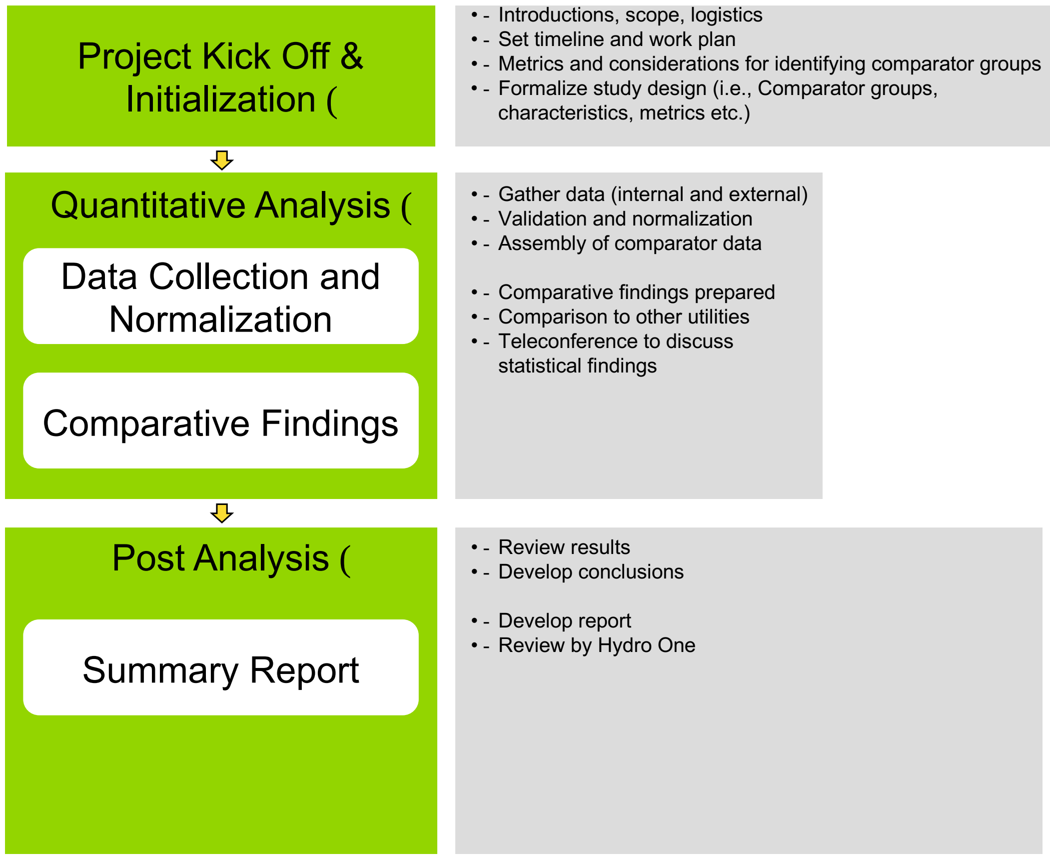
For this project, benchmarking was conducted to obtain information from comparator companies with sufficient details and transparency to understand the practices of those comparator companies. There are 4 sub-sections within this section:

- **Overview** – a brief overview of the primary steps in the benchmarking process
- **Information collected** – the data gathered for the comparisons, both from Hydro One and the comparator group
- **Comparator group selection** – Descriptions of the Canadian and U.S. utilities included in the study
- **Normalizing factors** considered – currency, AMI meter technology, AMI ! communications technology, territory density, utility size are factors reviewed for normalizing utility data for comparisons !

2.1 Overview

The study was structured to provide a replicable analysis that would give an accurate representation of Hydro One's AMI meter replacement costs and practices in comparison to other comparator utilities in a consistent manner. The major steps in the process are shown in Figure 1 below:

Figure 1 -- Project Approach



- **Project Kickoff and Initialization** – This stage was designed to determine the characteristics of an appropriate comparator group, the demographic data, and the metrics for making the comparisons.
- **Quantitative Analysis**
  - Data Collection and Normalization – This stage was designed to gather data through a detailed questionnaire directly completed by participating utilities. This step also involved the collection of additional information through industry research followed by normalization and data validation.
  - Comparative Findings – This stage involved creating a comparative summary with charts and graphs comparing results.
- **Post Analysis** – This stage was designed to review the results, draw out relevant observations about Hydro One's demographics, performance, and practices, and assemble them into a summary report.

2.2 Information Collected

To provide the appropriate basis for comparisons of costs and practices, the project team gathered three types of information from each of the comparator companies, as shown in Figure 2 below. Demographics were used in analyzing the results, and for assuring that there was an appropriate comparator group. Operational practice information helped in understanding replacement rates and approaches for replacing meters. Cost information was used for the final cost comparisons. Most of the data was from 2019YE, although in the case of meter replacement volumes, data was provided going both back and forward for 5 years.

Figure 2 -- Information gathered from Hydro One and the comparator group

Demographic Information

- Number of total meters in service
- Number of AMI meters in service
- Installation time period for AMI meters (years installed)
- Service territory density
- Meter technology and features
- Communications technology in use

Practice Information

- Expected Service Life for AMI meters
- Meters replaced in the past 5 years
- Plans for replacement over the next 5 years
- Experience with meter failures
- Staffing approaches for meter replacements

Cost Performance Data

- Labour costs for AMI meter replacement
- Meter acquisition costs
- Components included in the costs for meter replacement

2.3 Comparator Group Selection

In any benchmarking study, the goal is to assemble a comparator group for comparison that is representative of the industry, and specifically relevant to the subject under study. To achieve a broad panel of comparators, Guidehouse and First Quartile defined characteristics for evaluating and selecting comparators who would be appropriate for the analysis, including size (e.g. number of customers and meters), use of AMI meters, vintage of meters, territory density, etc.

The next step in comparator selection involved recruiting utilities to participate. This started with the utilities already involved in the annual First Quartile benchmarking study, which were expanded through approaching a number of other Canadian and U.S. utilities who met the basic demographic criteria listed above. In all, 44 utilities were either approached and invited to participate or were reviewed through desktop research.

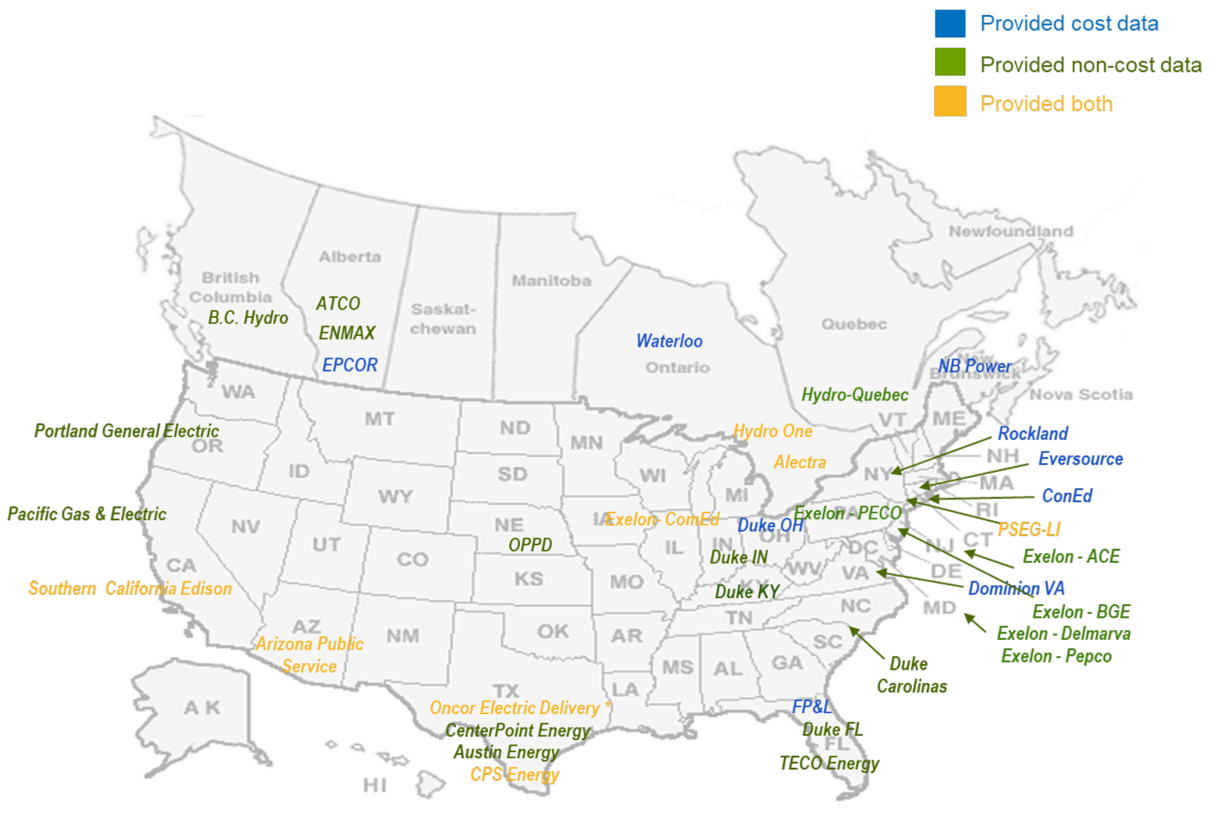
Substantial efforts were devoted to data collection, both in terms of finding utilities willing to share information about their AMI installations, and in finding ones able to provide the needed information, regardless of willingness. In the course of the study, 4 different efforts were made to gather information about potential comparator companies and their AMI meters, through a core (relatively detailed) survey, a supplemental survey, a simplified cost survey, and desktop research effort.

Data was collected from a total of 36 utilities (including Hydro One) for at least some portion of the required data. This included 9 Canadian utilities and 27 U.S. utilities. There was a mix of cost and non-cost data provided, including a few companies who provided one and not the other. The companies that chose not to participate cited various reasons for not participating:

- Lack of sufficient data
- Insufficient resources
- Competing priorities
- Inability to share proprietary data of vendors

Figure 3 below shows the utilities represented in the comparison panel. As can be seen, there is a mix of U.S. and Canadian utilities, mostly large utilities, with a few smaller ones. They all met the primary criterion that they are using AMI meters on a fairly broad scale. Beyond that, the panel is representative of the broader industry from the standpoint of experiencing various weather patterns, having both low-density and higher-density portions of service territory (although Hydro One has the lowest customer density among all comparators), and having both similar and different regulatory circumstances from Hydro One.

Figure 3 – Utilities in the Comparison Panel



In aggregate, the comparator group provides a fair representation of the portion of the North American utility industry utilizing AMI meter technology, so that Hydro One's results can be understood in the context of the industry.

2.4 Normalizing Factors

Normalization for this study was kept as simple as necessary. The initial step was to convert all costs to the same currency, in this case Canadian dollars.[1] Then the factors investigated included the AMI meter technology and communications technology. Almost all the utilities had very similar technologies in use, so no adjustments were needed. In the end, the costs were normalized on a per-meter basis (i.e. cost per meter) without other adjustments.

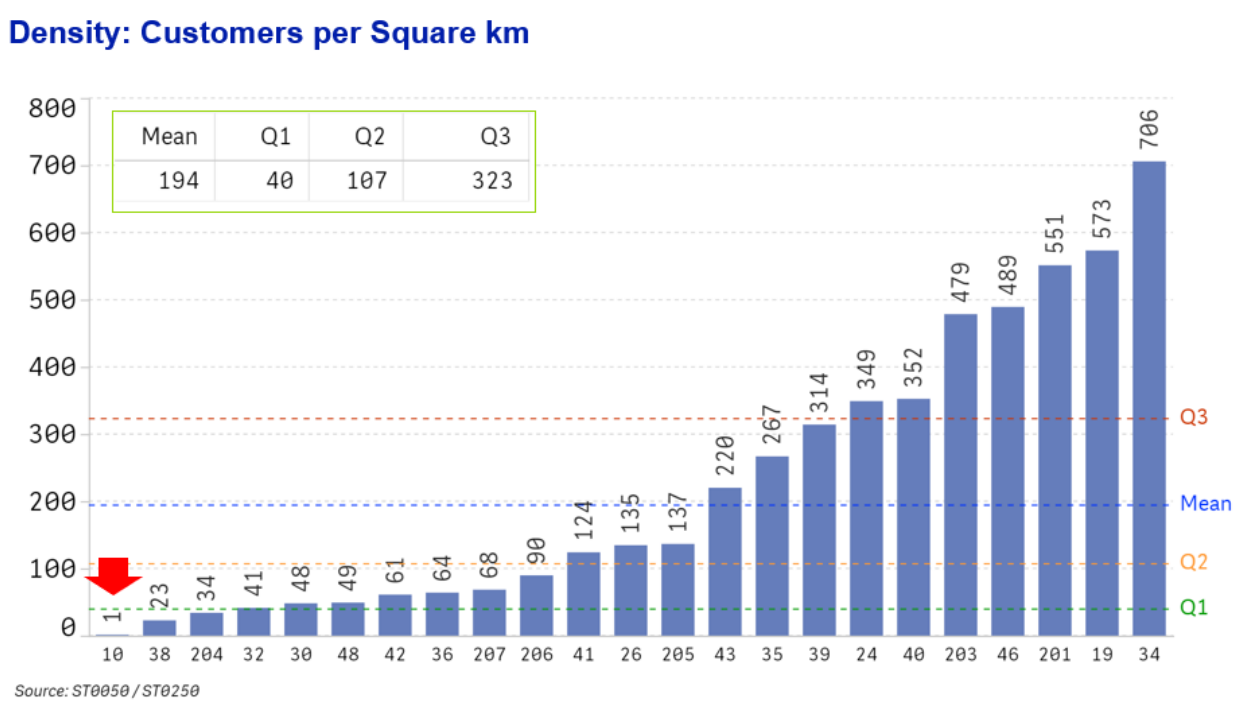
3 Benchmarking Observations

This section of the report summarizes the primary findings of the study, in the form of a series of observations. These are broken into four sub-sections: (1) service territory (2) AMI infrastructure, (3) AMI replacements, and (4) AMI costs. In the figures in this section, Hydro One is highlighted with a red arrow on the charts ( ).

3.1 Service Territory

HONI's service territory is the least densely populated as compared with comparators and includes a significant proportion of rural and remote locations that may be difficult or take longer to access. Figure 4 shows the relative density of the comparator panel.

Figure 4: Customer Density



• [1] Exchange rate used is 1.3269 CAD to USD. Source: U.S. Federal Reserve January 2, 2020. https://www.federalreserve.gov/releases/g5a/current/

3.2 AMI Infrastructure

Hydro One and the majority of comparators have fully-installed advanced metering infrastructure. 70% of the surveyed group indicated they have “complete, fully installed advanced metering (2-way communications)”. The remaining comparators have either partially completed installation, are in the pilot phase or selected “other” – typically indicating pre-development of AMI. Figure 5 shows the responses to the questions about the status of AMI metering in place.

Figure 5 – Current Status of Smart Metering/AMI Technology

ST0300| What is the current status of smart metering/AMI technology at your company?

	10	19	24	25	26	28	30	31	32	33	34	35	36	
Complete, fully-installed advanced metering (2-way communications)	◆	-	◆	◆	◆	-	-	◆	◆	◆	◆	-	◆	◆
Partial completion of full implementation for smart meters		◆	-	-	-	-	-	-	-	-	-	◆	-	-
Planning pilot/test implementation	-	-	-	-	-	◆	◆	-	-	-	-	-	-	-

Source: ST0300

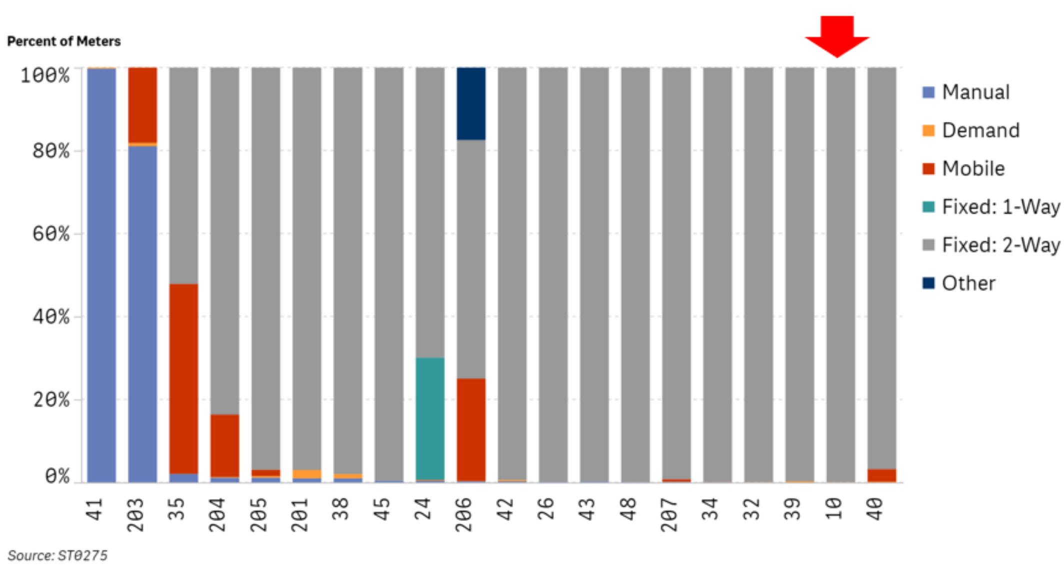
ST0300| What is the current status of smart metering/AMI technology at your company?

	39	40	41	42	43	45	48	201	203	204	205	206	207
Complete, fully-installed advanced metering (2-way communications)	◆	◆	-	◆	◆	◆	◆	◆	-	-	◆	-	◆
Partial completion of full implementation for smart meters	-	-	-	-	-	-	-	-	-	◆	-	◆	-
Currently in pilot/test implementation	-	-	-	-	-	-	-	-	◆	-	-	-	-
Other	-	-	◆	-	-	-	-	-	-	-	-	-	-

Source: ST0300

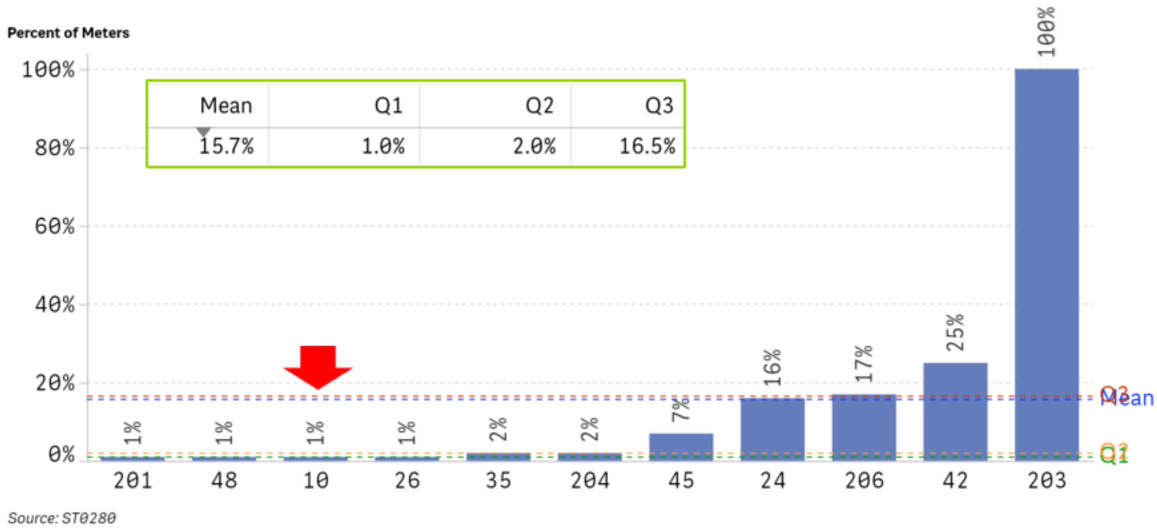
HONI’s meters consist almost 100% of fixed 2-way meters, which aligns with the finding that fixed 2-way meters make up the majority of installed meters for 88% of surveyed participants. Figure 6 shows the meter types in use for the comparison panel.

Figure 6 – Percent of In-Use Meters by Type



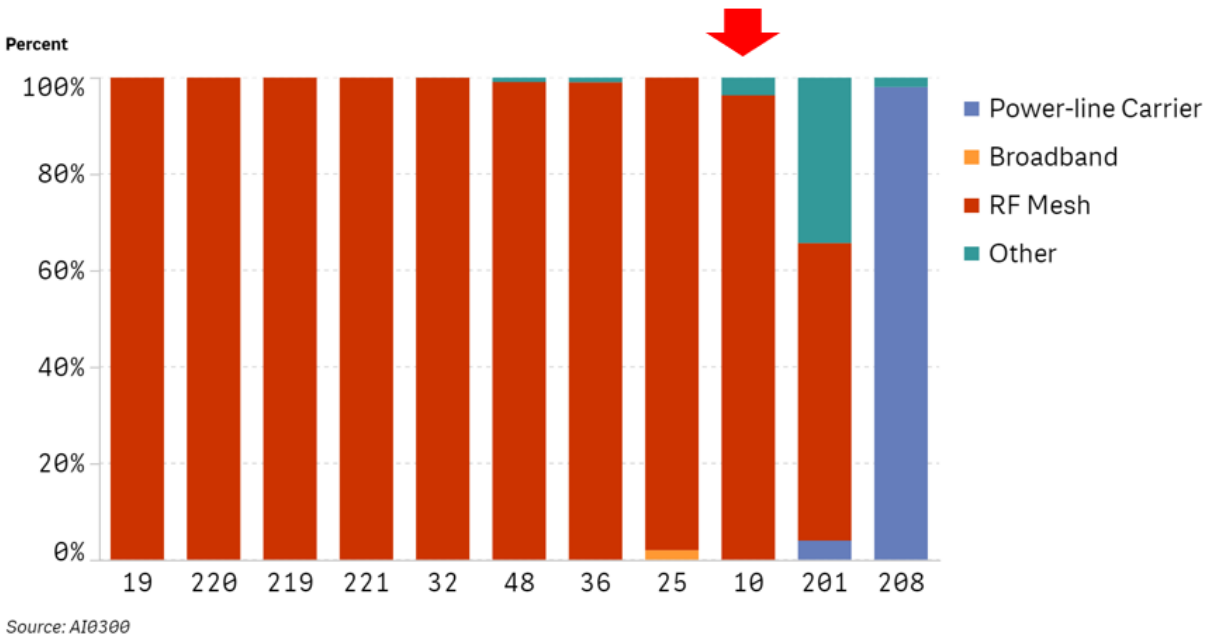
Approximately 1% of HONI's AMI meter reads are obtained manually, which is well below the mean of 15.7%; there are only a few comparators with a significant amount of AMI meters being read manually, with one at 100%. The mode of the comparator group for manual meter reads is 1%, which aligns with HONI; note that several of the comparators with high manual read rates also still have some manual meters, PLC meters or are transitioning to 2-way smart meters. Figure 7 illustrates the responses of the utilities regarding manual reading of AMI meters.

Figure 7
Percent of Currently Installed 1-Way or 2-Way AMI Meters Being Read Manually .



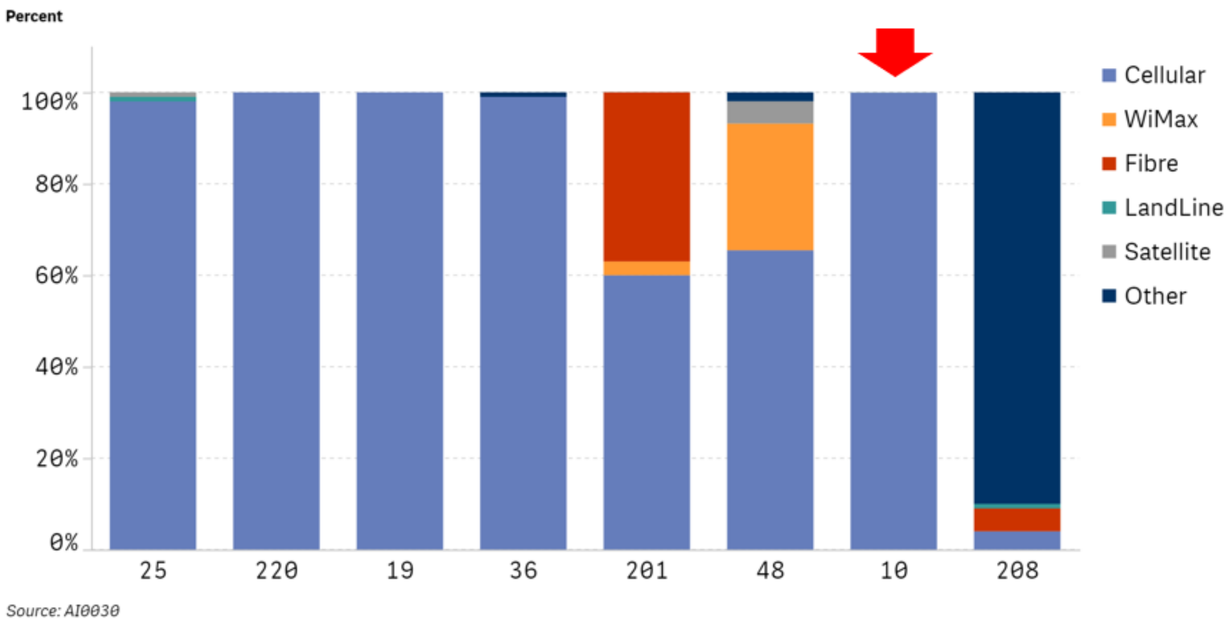
HONI's meters almost entirely use RF Mesh and cellular communication, aligning with the most common technologies used amongst the comparators. Beyond the basic meter, comparators identified that recently purchased meters have remote disconnection/reconnect capabilities, multiple registers that can capture data, and last gasp capability. Figure 8 shows the basic communication technology in use for the AMI meters.

Figure 8 – Percent of Meters Using Each Communication Technology



With respect to the technology in use for network take points, Hydro One is among 63% of respondent companies whose network takeout points are almost 100% cellular. Three comparators from the group of respondents use notable proportions of Fibre, WiMax and MPLS microwave. Figure 9 shows the types of communications technology used for the network takeout points.

Figure 9 – Percent of Overall Network Takeout Points Using Each Technology

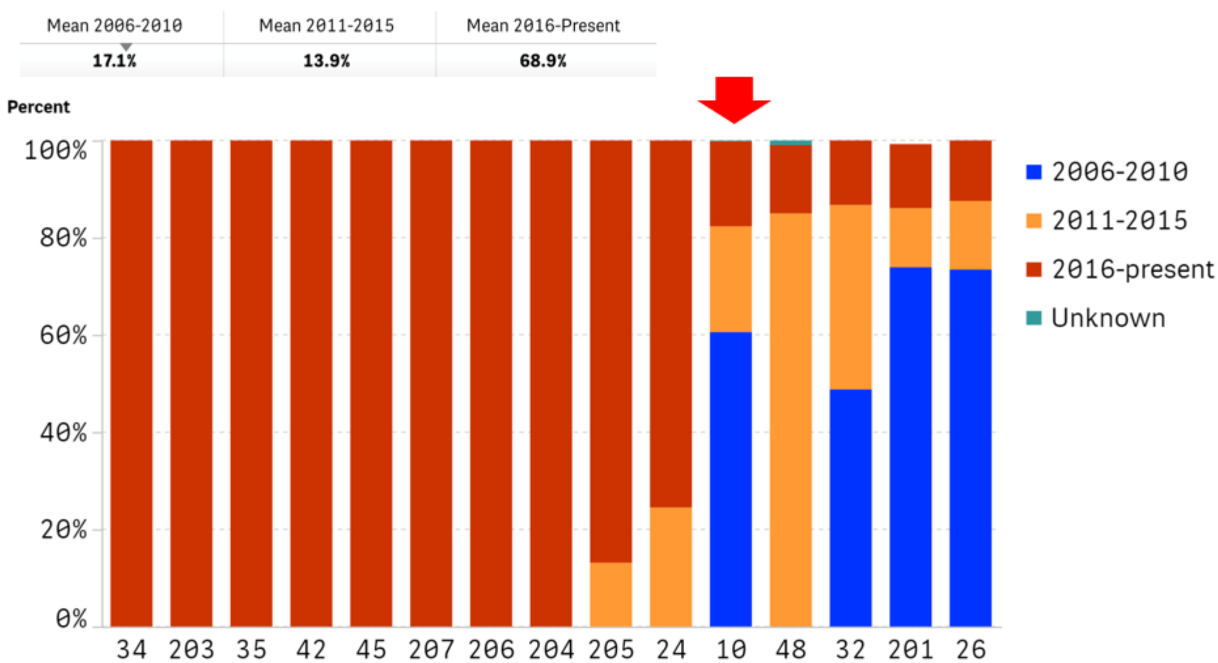


3.3 AMI Replacements

3.3.1 Meter Installation and Expected Service Life

Hydro One has a greater percentage of AMI meters that were installed 10 or more years ago than the majority of comparators. 61% of HONI's meters were installed in 2000-2010, while the comparator average for the same vintage was 30%. This indicates that HONI's AMI meters are older than the group. Since HONI's meters are first generation AMI meters, it is expected that HONI will need to replace its meters in the near future as meters reach end of life or become obsolete. Figure 10 shows details of when each company's AMI meters were installed.

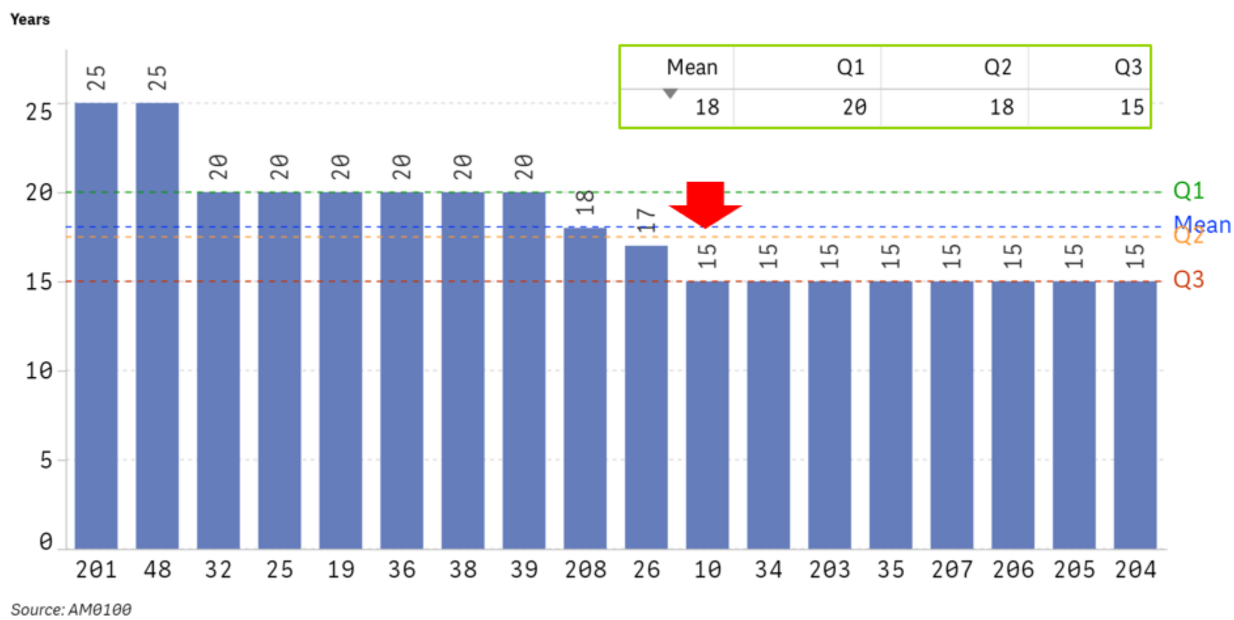
Figure 10
Percent of Current In-Service AMI Meters Installed by Time Period (Years of Installation) .



Source: ST1625

Hydro One has an expected AMI meter service life that is similar to the mode of the comparator group. As one of the early adopters of AMI meters, HONI is among 44% of respondents who have an expected service life of 15 years (some of these utilities were also early adopters of AMI), which represents the mode of the group; the mean expected service life of the entire group is 18 years. Figure 11 shows the expected service life of AMI meters for the respondents.

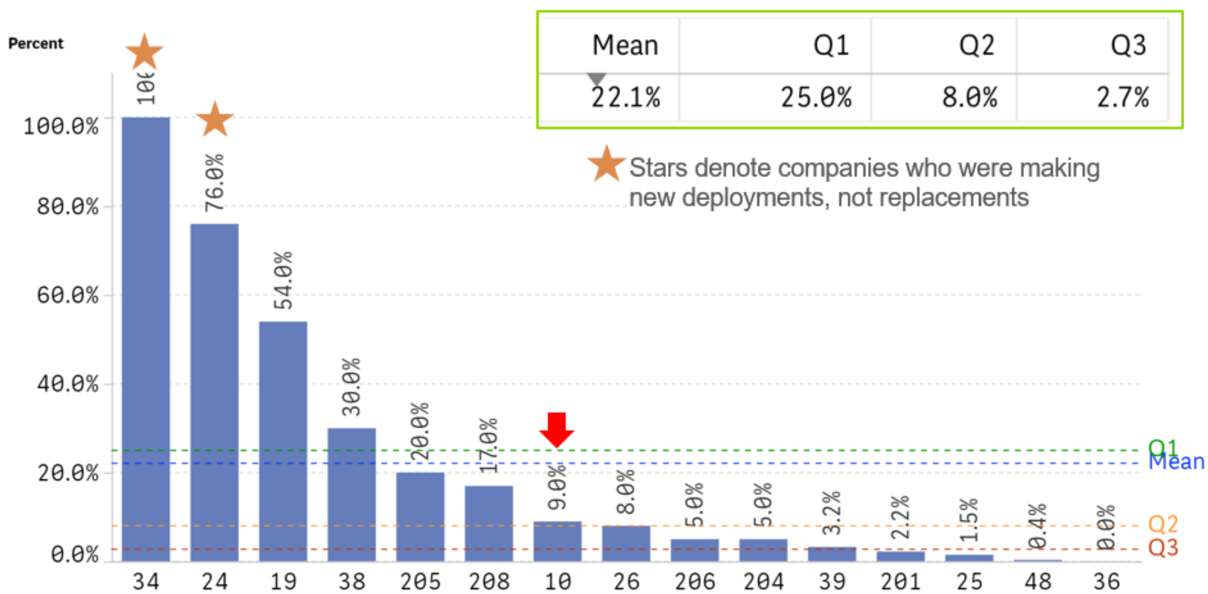
Figure 11 – Expected Service Life for AMI Meters



3.3.2 AMI Meter Replacement Rates

HONI's AMI meter replacement rate over the past 5 years (9%) is below the mean of the comparator group (22%) but slightly above the median (8%). Hydro One's replacements over the last 5 years were primarily due to failure of older meters within the system, which were deployed in the 2007-2010 time frame. The two comparator utilities with the highest replacement rates over the past 5 years responded that the majority of their in-service AMI meters were new deployments (i.e., not replacements) which were installed since 2016. In contrast, HONI over the past 5 years was in a different state of deployment which entailed replacing already installed first generation meters primarily due to failure. Figure 12 shows the recent replacements.

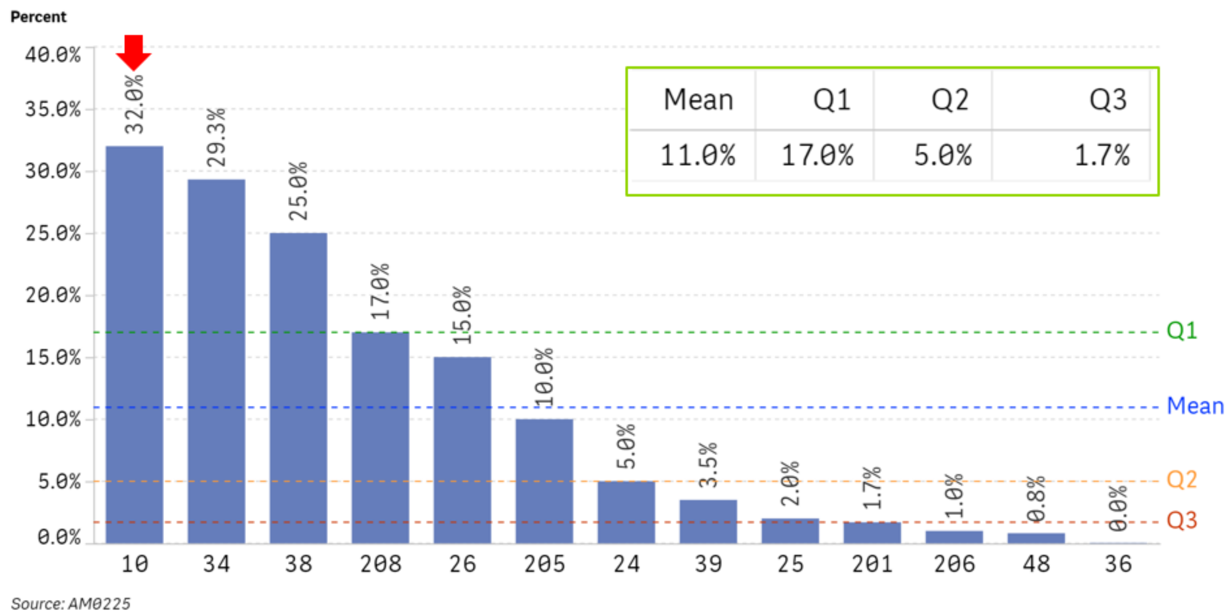
Figure 12 -- Percent of Existing AMI Meters Replaced in Last 5 Years



Source: AM0200

Given its planned mass deployment of next generation AMI meters (and not just replacements of failed meters), Hydro One is expected to have the highest replacement rate in the comparator group over the next 5 years (32% versus the comparator mean of 11%). With an AMI system that was deployed in the 2006-2010 time frame and based on older AMI technology, HONI is aiming to complete a mass replacement program, and expects to save on installation costs (compared to individual replacements) as a result of deploying on a mass scale.

Figure 13 -- Percent of Existing AMI Meters Planned to be Replaced in Next 5 Years



3.3.3 Meter Technologies

Hydro One currently uses smart meter functions similarly to the comparators; its future use cases also align with functions which others are seeking in their next generation AMI deployments. HONI either currently uses or plans to use the AMI meter capabilities for all the major categories as reported by the comparator group, including data analytics, system planning and theft identification as the top three uses for AMI system data. Comparators also identified numerous common capabilities to pursue for their next generation AMI deployments. HONI defined its use for the specific capabilities in the following way:

Capabilities that are currently used for a small portion of Hydro One's meters:

- Remote disconnect/re-connect !
- Voltage monitoring !

Capabilities that are not currently used by Hydro One but planned for all future meters: !

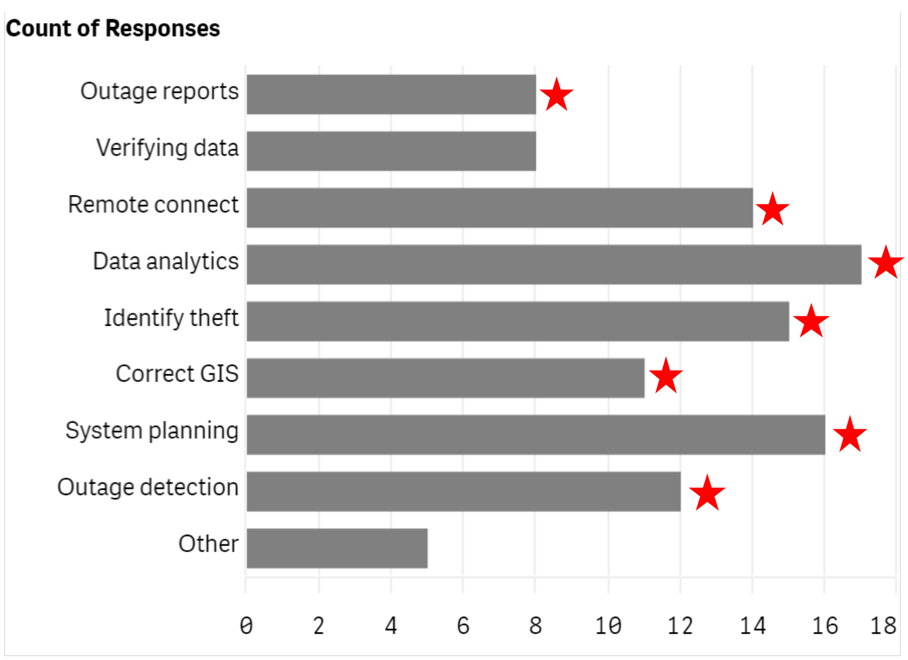
- Temperature monitoring / heat detection !
- Open standards (for future interoperability, allowing multi-vendor solutions) !
- Artificial intelligence at the meter (VS analytics at back office) !

Capability that is in current use for all Hydro One meters !

- Cyber security compliance

Figure 14 shows the number of responding companies who noted they are currently using specific capabilities. The red stars are the ones where Hydro One is using the capabilities.

Figure 14 – Present Uses for AMI System Data (Excluding Remote Meter Reading, Billing)



3.3.4 Labour Resources

HONI's labour resource type used to replace meters aligns with most of the comparator companies. While the job title for HONI's labour resource is "Meter Reader", the primary responsibilities are equivalent to those described under the title of "Field Service Worker" in the First Quartile benchmarking questionnaire. HONI has indicated that its meter readers are its lowest cost option. Similar to the comparator companies, HONI does not contract out labour for replacement of AMI meters; only one of the comparators indicated the use of contract work for AMI meter replacements. Figure 15 shows the resource types used for meter replacement work.

Figure 15
Type of Resources Conducting the Majority of the Residential Meter Replacement Work

	10	19	25	32	36	201	208
Field Service worker	-	♦	-	♦	♦	♦	♦
Trained technician/electrician	-	♦	♦	-	-	-	♦
Meter reader or equivalent	♦	-	-	-	-	-	-

	AI0120.100
208	3 job classes, i.) powerline technician (linemen) | ii.) field service rep (no lines training) | iii.) meter technicians | powerline technicians and field service reps do most of the AMI replacements, meter technicians are used for more complicated jobs (i.e. PLTs)

Hydro One's labour resource type used for communications equipment work differs from that of the comparators due to its required use of journey level line workers with bucket trucks for meter communication equipment that is primarily mounted at the top of distribution poles. In contrast, comparators are able to use meter technicians and/or communications technicians to service communications equipment that may be at a lower serviceable height level without the use of bucket trucks. Figure 16 provides the responses from the utilities.

Figure 16 -- Type of Resources Conducting the Majority of the Residential Network Communications Equipment Work .

	10	19	25	32	36	48	201	208
Communications technician	-	♦	♦	♦	-	-	-	-
Meter technician or similar	-	♦	-	-	♦	-	♦	-
Power line journey-level lineworker (with bucket)	♦	-	-	-	-	♦	-	-
Other	-	-	-	-	-	-	-	♦

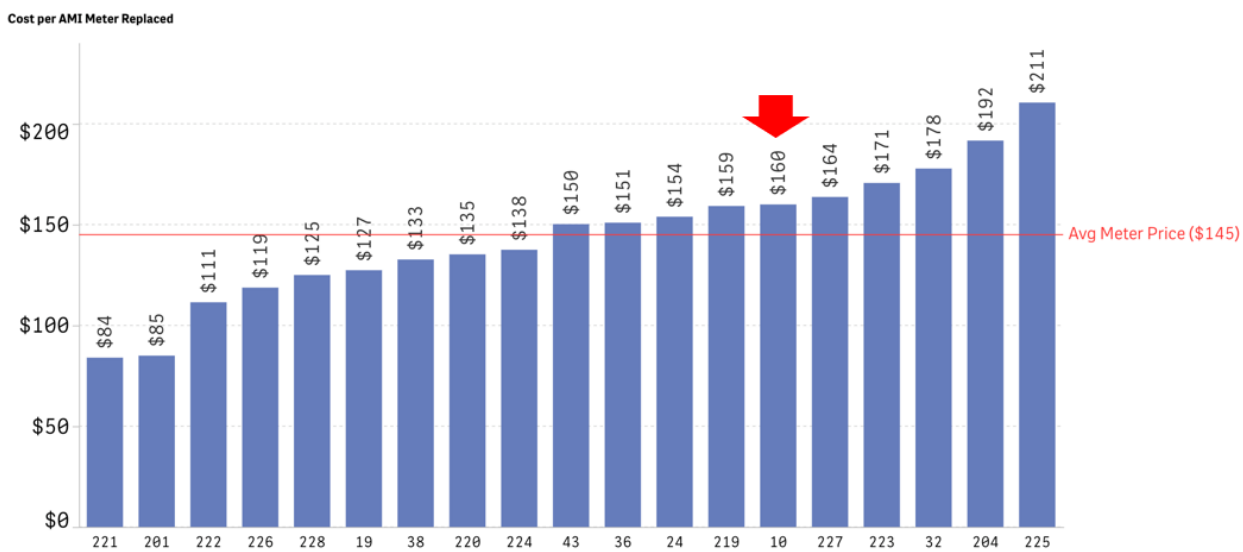
Source: AM0130

	AI0130.100
208	Powerline network, maintained by substation technicians... Microwave network maintained by telecom techs... still mostly in-house (99%) For radio frequency mesh networks, they have bucket trucks with linemen that help out

3.4 AMI Costs

Hydro One's average meter acquisition cost ($160) is 10% higher than the mean of the comparator group ($145). These acquisition costs reflect contracted prices for low volume individual meter replacements and do not incorporate scale economies that would be expected with bulk purchases. Some of the comparators that have recently completed major meter deployments have shown lower per meter purchase costs, indicating that bulk purchases lend themselves to lower purchase costs than Hydro One currently experiences with their low volume purchases. However, it should be noted that as more advanced meter features become available, the overall cost of meters may increase. Figure 17 shows the purchase costs for AMI meters replaced.

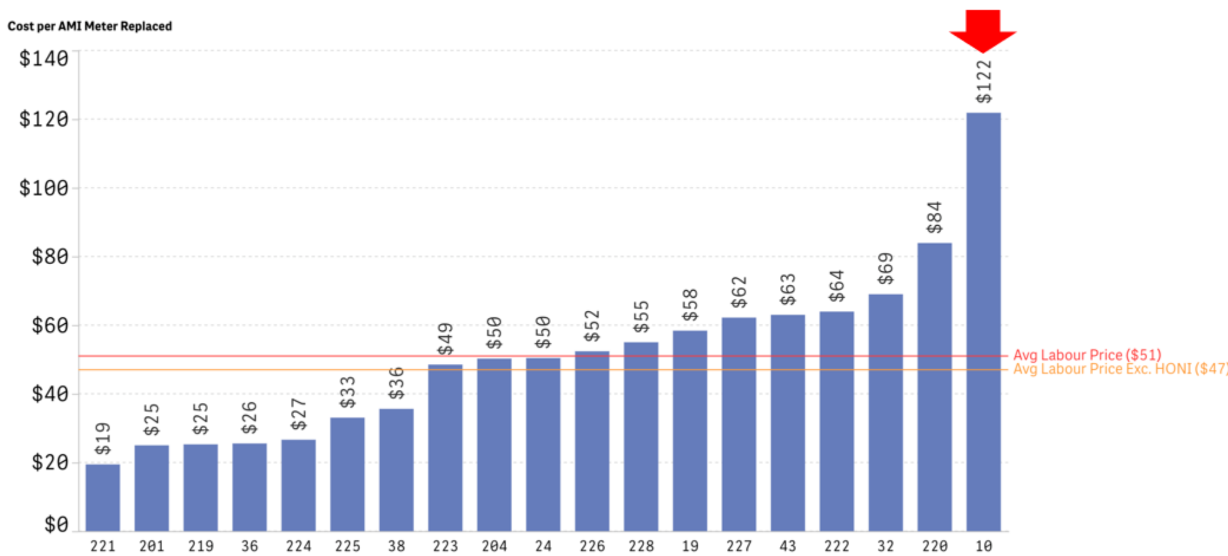
Figure 17 -- Meter Purchase Cost for AMI Meters Replaced



HONI's average labour cost per meter of $122 is higher than the comparator average of $51 ($47 excluding HONI labour cost), as shown in Figure 18 below. HONI's labour costs reflect the challenges related to its service territory, which covers more surface area than the average comparator and includes a significant proportion of rural and remote locations that can be difficult to access and require additional travel time to reach. As shown above in Figure 4, Section 3.1, HONI's territory is significantly less dense than the least dense comparator.

Data shown in the figure for HONI is for individual meter replacements; whereas the data shown for the comparators represents a mix of individual meter replacements and mass deployments. Relative to individual replacements, mass deployments have a cost advantage as utility companies can replace a large batch of meters at the same time – this is especially important to utilities with large service territories similar to that of Hydro One.

Figure 18 – Labour Cost for AMI Meters Replaced



Note: labour costs are shown without overheads !

Hydro One Billing & Call Centre Benchmarking: Final Report

imagine your future®

Project Competencies/Information Provided

ISG™ imagine your future®

Project Competencies

The Ontario Energy Board (OEB) has asked Hydro One Networks, Inc. (HONI) to provide an independent benchmark of its corporate support functions rate card in its EB-2016-0152 Decision.

- HONI seeks a provider with a proven record of accomplishment in delivering high-quality benchmark services:
  - For similar sized companies
  - That has a strong history of providing consulting services to Utilities
  - That can support benchmark findings in a regulatory hearing
  - With the scope to include Billing and Call Centre

Information Provided & Used

In addition to the Data Collection worksheets provided by ISG, HONI has provided additional information.

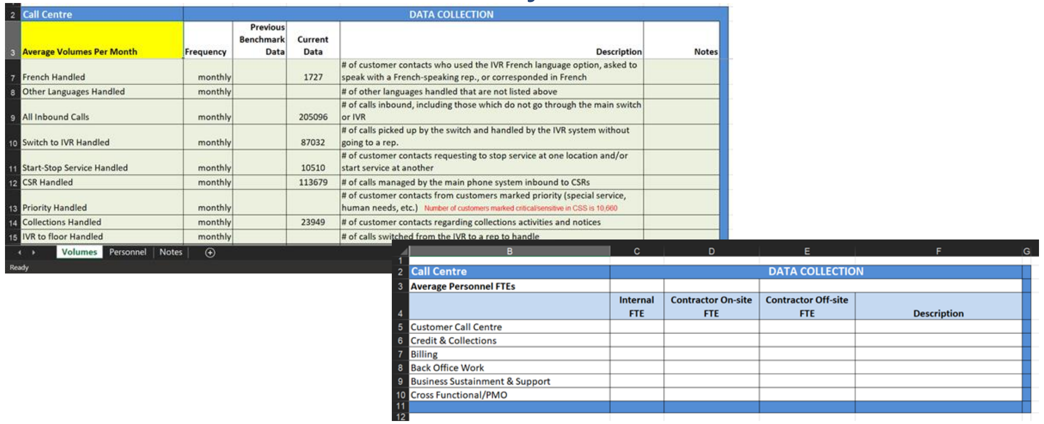
- Billing Data volumes, activities, quality, assets, and App Support
- Credit & Collections volumes, activities, and assets
- Call Centre volumes, activities, quality, assets, and miscellaneous additions (WFM and BCC)
- Security Deposits as of Jan 1, 2020
- Interviews with Hydro One
- Confidential FTE allocation and costing information with loadings

Benchmarking Approach

ISG Benchmarking Approach

ISG used a benchmarking approach that has been proven at previous benchmarks for Hydro One and is familiar to regulators.

Project Data



Call Centre	DATA COLLECTION				
Average Volumes Per Month	Frequency	Previous Benchmark Data	Current Data	Description	Notes
French Handled	monthly		1727	# of customer contacts who used the IVR French language option, asked to speak with a French-speaking rep., or corresponded in French	
Other Languages Handled	monthly			# of other languages handled that are not listed above	
All Inbound Calls	monthly		205096	# of calls inbound, including those which do not go through the main switch or IVR	
Switch to IVR Handled	monthly		87032	# of calls picked up by the switch and handled by the IVR system without going to a rep.	
Start-Stop Service Handled	monthly		10510	# of customer contacts requesting to stop service at one location and/or start service at another	
CSR Handled	monthly		113679	# of calls managed by the main phone system inbound to CSRs	
Priority Handled	monthly			# of customer contacts from customers marked priority (special service, human needs, etc.) Number of customers marked critical/sensitive in CSS is 10,660	
Collections Handled	monthly		23949	# of customer contacts regarding collections activities and notices	
IVR to floor Handled	monthly			# of calls switched from the IVR to a rep to handle	

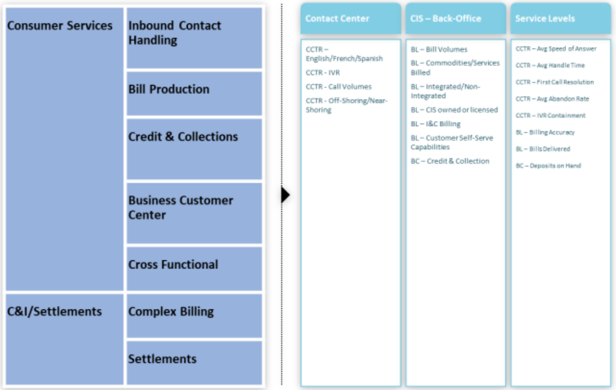
Volumes | Personnel | Notes

Call Centre	DATA COLLECTION			
Average Personnel FTEs				
	Internal FTE	Contractor On-site FTE	Contractor Off-site FTE	Description
Customer Call Centre				
Credit & Collections				
Billing				
Back Office Work				
Business Sustainment & Support				
Cross Functional/PMO				

Comprehensive picture of targeted scope

1 Mapping

ISG Services Framework



2 Comparison

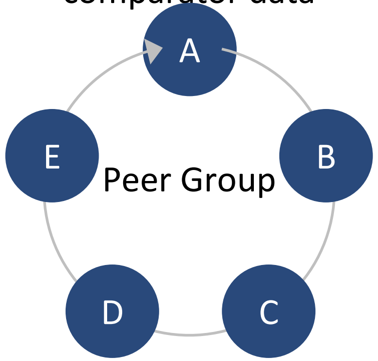
3 Analysis

ISG Database

Selection of comparable data in terms of:

- Service scope
- SLAs – where available
- Volumes
- Complexity
- Cost Model

Up-to-date comparator data



Results

- Market costs
- Service design and SLAs
- Cost trends, volume effects and/or other key drivers
- Improvements or efficiencies planned
- Regulatory and/or other unique business requirements or constraints

ISG Benchmarking Approach

ISG maps HONI's Call Centre and Billing services into a Utility Customer Services Industry Framework.

Consumer Services	**Inbound Contact Handling**
	Bill Production
	Credit & Collections
	Business Customer Centre
	Cross Functional
C&I/Settlements	**Complex Billing**
	Settlements

Contact Centre

- CCTR – English/French/Spanish
- CCTR - IVR
- CCTR - Call Volumes
- CCTR - Off-Shoring/Near-Shoring

CIS Back Office

- BL – Bill Volumes
- BL – Commodities/Services Billed
- BL – Integrated/Non-Integrated
- BL – CIS owned or licensed
- BL – I&C Billing
- BL – Customer Self-Serve Capabilities
- BC – Credit & Collection

Service Levels

- CCTR – Avg Speed of Answer
- CCTR – Avg Handle Time
- CCTR – First Call Resolution
- CCTR – Avg Abandon Rate
- CCTR – IVR Containment
- BL – Billing Accuracy
- BL – Bills Delivered
- BC – Deposits on Hand

Peer Group

ISG™ imagine your future®

ISG's Benchmarking Peer Groups

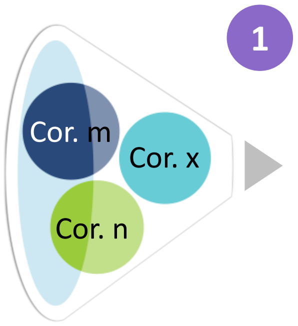
ISG's approach for selecting appropriate comparators withstands regulatory scrutiny.

Key selection criteria will be agreed with all parties at the start of the process.

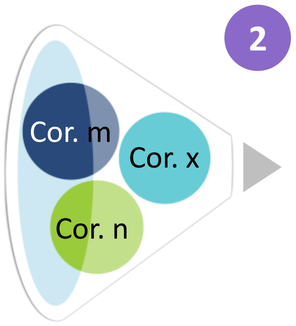
ISG then selects those reference group members that **best fit** to the services.

- ✓ ISG provides and aligns with client on a Peer Group
- ✓ Peer Group members consist of companies that share business and technology attributes
- ✓ Each group consists of at least 5-6 comparable North American utilities
- ✓ Data shown represents the mean performance of the group
- ✓ Separate Peer Groups may be selected for each corporate support function

ISG Cost Database



Peer Group Candidates	
Corporation 01	Corporation 41
…	…
Corporation 40	Corporation 80



Final Peer Group
Corporation 01
…
Corporation 6

1. Pre selection

ISG identified possible candidates from the ISG contractual and cost Databases based upon the agreed key selection criteria, e.g.,

- General service scope
- Geographic markets
- Currencies
- Data validity

2. Service Alignment

ISG selected the data **appropriate for the in-scope benchmarked services** according to the agreed ISG Service and Product Catalogue:

- Industry and Service spread / scope
- Service quality
- Service volumes
- Service complexity and technology

Peer Group

All utilities were chosen from the North American market and serve between 800,000 and 3.5 million customers.

Utility	Canada/US	Billing	Call Centre	Unionized	Electric/Gas	Non-Integrated/ Integrated
Hydro One	Canada	In-house	In-house	Yes	Electric	Non-Integrated
Utility A	US	Partial Off	In-house	No	Electric	Non-Integrated
Utility B	US	Partial On	In-house	Yes	Gas	Non-Integrated
Utility C	US	Partial Off	On	Yes	Electric	Integrated
Utility D	Canada	Partial Off	Near	No	Electric/Gas	Non-Integrated
Utility E	Canada	In-house	In-house	Yes	Electric	Integrated
Utility F	Canada	In-house	In-house	Yes	Electric	Non-Integrated
Utility G	Canada	In-house	On	No	Electric	Non-Integrated
Utility H	US	In-house	In-house	Yes	Electric	Non-Integrated
Utility I	Canada	In-house	In-house	Yes	Electric	Non-Integrated

Off = Offshore   Near = Nearshore   On = Onshore

Report Results

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Historical Trending

ISG benchmarked HONI in 2012 and 2019 and can provide the following historical context.

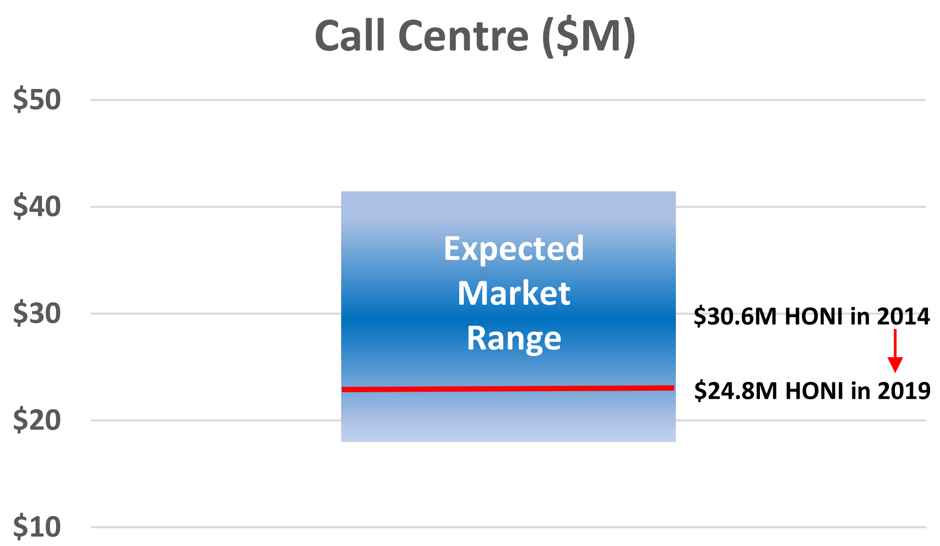
Metric	2012* monthly avg	2019** monthly avg	Comments
Inbound Calls	215k	160k	Digital Program efforts shift calls to other channels
Incoming Calls to Reps	115k	76k	Digital Channels and an increase in IVR containment
Non-Natural Language IVR Containment	45%	52%	Optimization of the existing Non-Natural Language IVR
Average Speed of Answer	37 seconds	31 seconds	Optimized workforce scheduling of CSRs
Average Abandon Rate	4.2%	3.0%	Optimization of the IVR and increased containment
Total Bills Sent	1,233,000	1,288,901	In line with normal customer growth
Number of Complex Bills	7,700	3,178	New SAP implementation (what the new system can calculate)
Broken Pay Arrangements	2,845	1,285	Optimized Credit/Collections policy (will increase due to COVID19 impacts)
Deposits on Hand	$38.8m	$7m	Optimized Credit/Collections policy

* Service Provider delivered Call Centre and Billing Services in an outsourced model in 2012

** HONI provided Call Centre and Billing Services in-house in 2019 (after re-patriation of the services)

Call Centre

Call Centre cost for Hydro One and the Low, High and Average for the Peer Group.

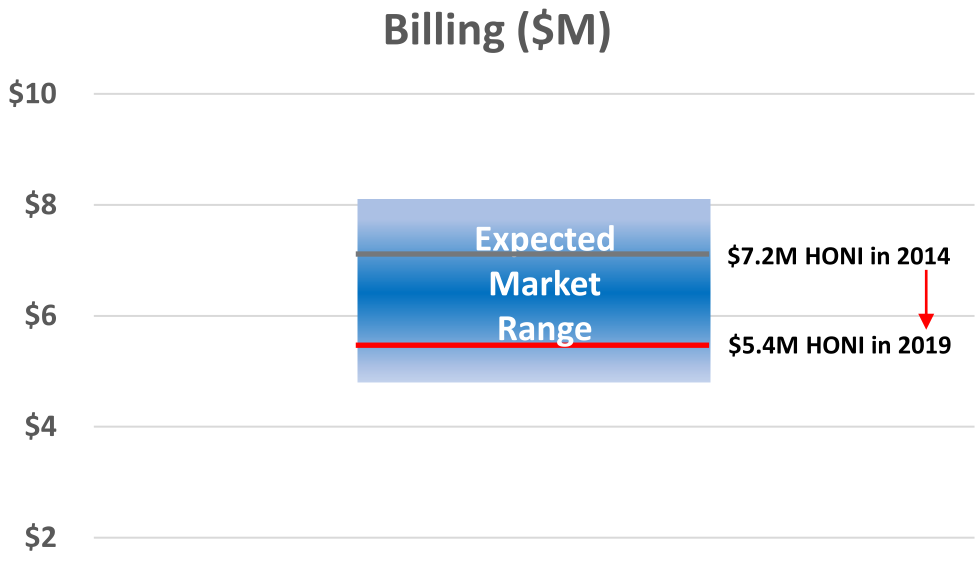


- Call Centre cost at Hydro One is below the market average.
- The market ranges from $18M to $41.4M with an average cost of $26.3M.

Business Area	Key Sizing Metric	Hydro One	Peer Group Average
Call Centre	CSRs	242	271
	IVR Handled	52%	38.4%
	Average Handle Time	366 seconds	404 seconds
	Number of Customers	1,400,000	1,579,645

Billing

Billing cost for Hydro One and the Low, High and Average for the Peer Group.

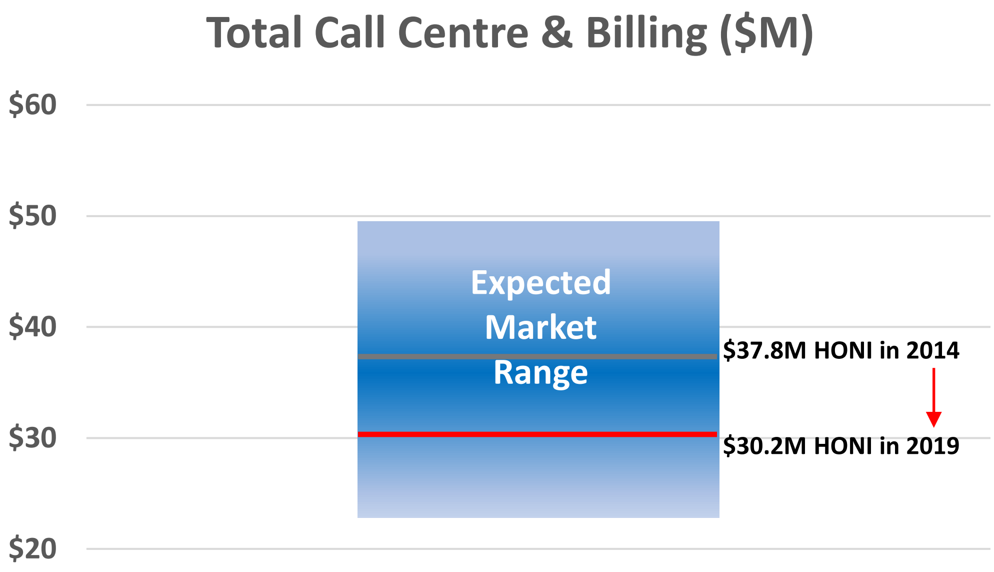


- Billing cost at Hydro One is towards the lower end of the market range.
- The market ranges from $4.8M to $8.1M with an average cost of $7.1M.

Business Area	Key Sizing Metric	Hydro One	Peer Group Average
Billing	Billing FTEs	58.73	77.4
	Bills Produced	1,288,901	1,450,720
	Number of Customers	1,400,000	1,579,645

Total Call Centre & Billing

Total Call Centre & Billing cost for Hydro One and the Low, High and Average for the Peer Group.



- Total Call Centre and Billing spend at Hydro One is 9% below the market average.
- The market ranges from $22.8M to $49.5M with an average cost of $33.4M.
- HONI has reduced costs approximately 20% since repatriating services while meeting the OEB's Customer Focus (Service Quality and Customer Satisfaction) Metrics on the Consolidated Scorecard of Electricity Distributors.

Standard Adjustments

The table below shows the adjustments that ISG applied/considered to both Lines of Business to normalize industry costs.

Business Area	Adjustment Type	Adjustment Component	Adjustment
Call Centre & Billing	Currency Exchange	2019 USD to CAD conversion for 4 US based comparators	1.3269
	COLA/CPI	Cost of Living Adjustment/Consumer Price Index	N/A since all costs were 2019 actuals
	Unionization	Unionization factor for 3 non-unionized comparators	38.6%
	Localization	Localization factor for work performed in the GTA	N/A since work is performed in Markham and London

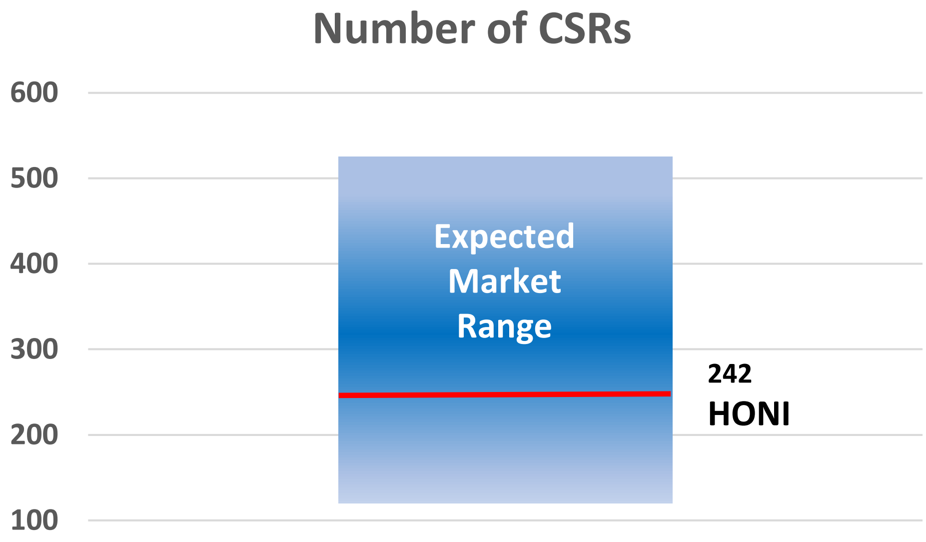
Business Area Specific Adjustments

The table below shows the adjustments that were made for the various adjustment types to each Business Area.

Business Area	Adjustment Type	Adjustment Component	Average Adjustment
Call Centre	Service Level	% of calls answered in 30 seconds adjusted for 3 comparators	3.89%
	Complexity	On-shore/In-house requirement adjusted for 3 comparators	12.2%
Billing	Complexity	On-shore/In-house requirement adjusted for 4 comparators	5.6%

Customer Service Reps (CSRs)

Number of CSRs for Hydro One and the Low, High and Average for the Peer Group.



- Number of CSRs at Hydro One is below the peer group average.
- The market ranges from 125 to 525 with an average of 270.6 CSRs.

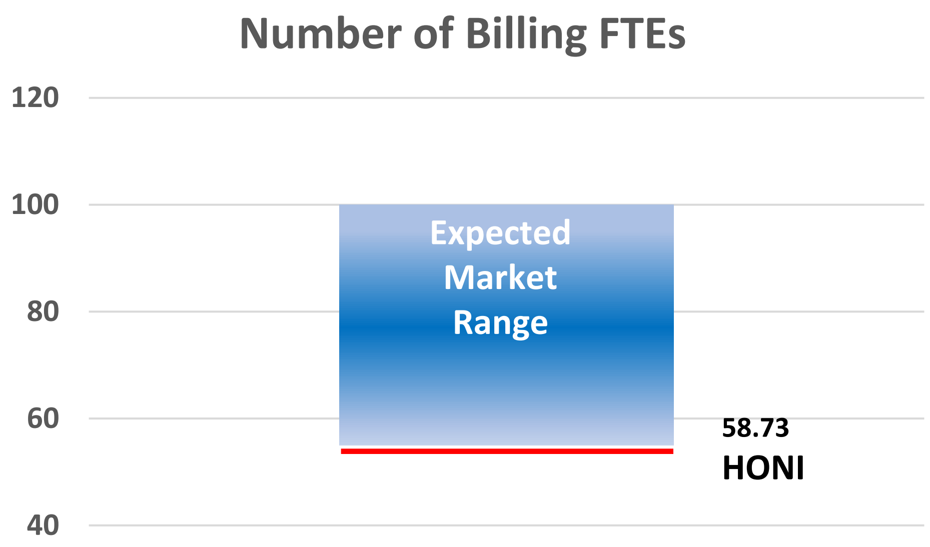
Cost per CSR

Cost per CSR for Hydro One and the Low, High and Average for the Peer Group.

- Cost per CSR at Hydro One is slightly below the peer group average.
- The market ranges from $80k to $120k with an average of $100k.

Number of Billing FTEs

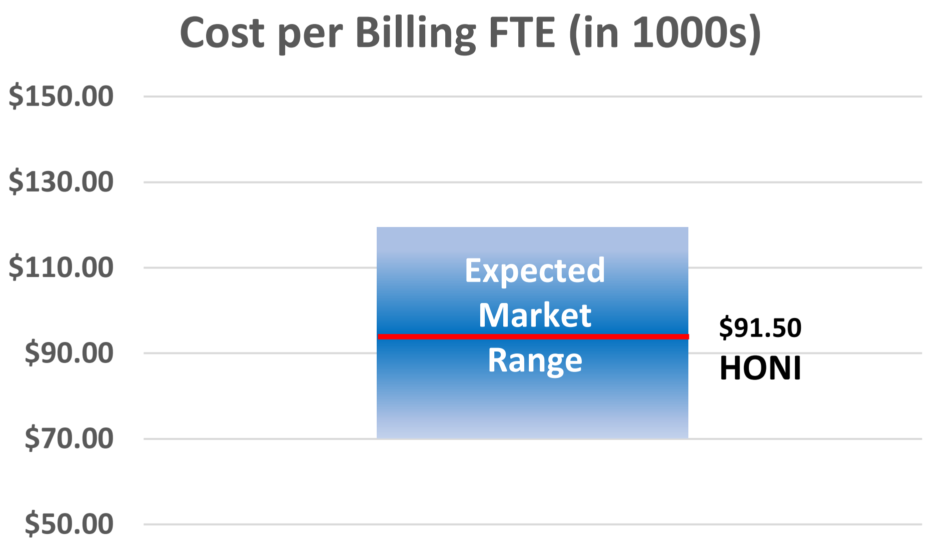
Number of Billing FTEs for Hydro One and the Low, High and Average for the Peer Group.



- Number of Billing FTEs at Hydro One is well below the peer group average.
- HONI is already using RPA in Billing Operations which contributes to its low FTE count.
- The market ranges from 60 to 100 FTEs with an average of 77.4 FTEs.

Cost per Billing FTE

Cost per Billing FTE for Hydro One and the Low, High and Average for the Peer Group.



- Cost per Billing FTE at Hydro One is similar to the peer group average.
- The market ranges from $70.1k to $119.5k with an average of $91.2k.

Potential Improvements

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Areas for Potential Improvement – Speech Assessment

- Of the 11 utilities benchmarked
  - 7 of the 11 are using NLU Speech
  - 4 of the 11 are using Directed Speech
  - 7 of the 11 utilities recognize 5% - 15% increase in containment by deploying NLU Speech

- Each additional 1% of IVR Containment can result in a Benefit (Savings) of $330,000 - $400,000 per year (calculated from three U.S. utilities and converted to Canadian dollars)

- Estimated Capital investment ranges from $10m - $15m for NLU Speech

* Utility A, B, and K were part of the Benchmark Peer Group that ranged from 10% - 52% with Hydro One matching the high of 52%

** The other utilities come from ISG Research and not necessarily the Hydro One Peer Group

Company	Modality	Containment
Hydro One	DTMF	52%
Utility A*	NLU Speech	46%
Utility B*	NLU Speech	40%
Utility C	NLU Speech	50%
Utility D	NLU Speech	62%
Utility E	NLU Speech	68%
Utility F	NLU Speech	51%
Utility G	NLU Speech	61%
Utility H	Directed Speech	70%
Utility I	Directed Speech	65%
Utility J	Directed Speech	50%
Utility K*	Directed Speech	46%

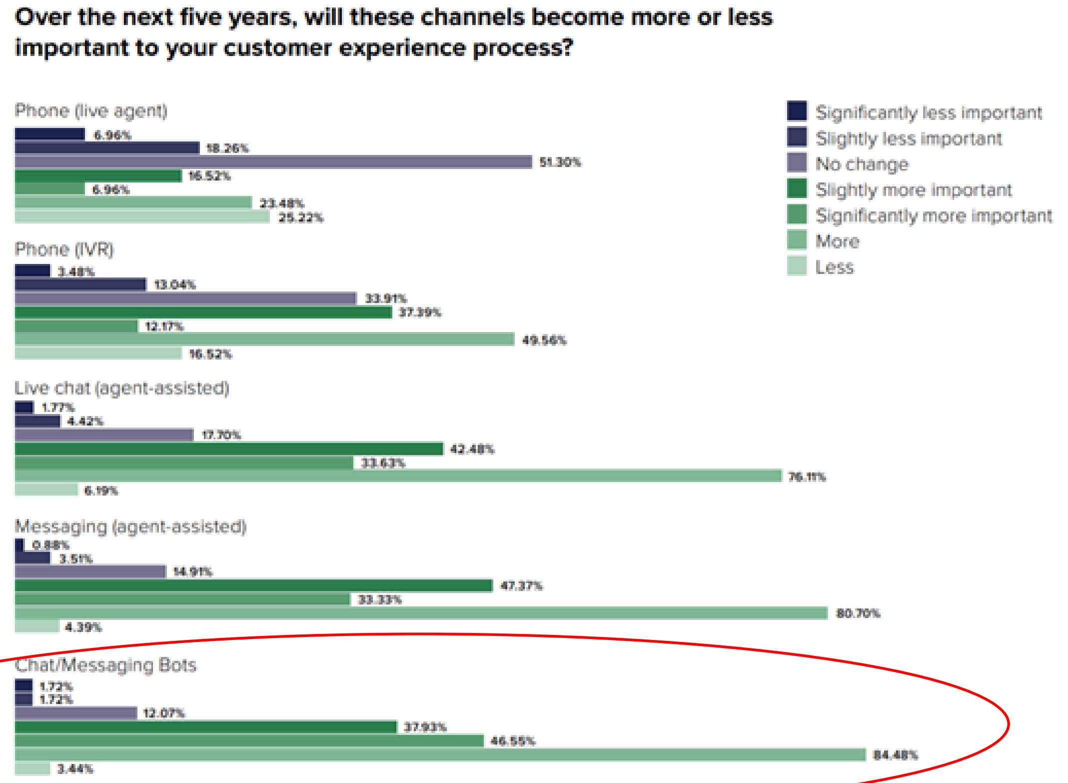
Source: ISG Research

Areas for Potential Improvement – Chat/Chat Bots

Many utilities today are optimizing the IVR with Natural Language and adding additional digital technologies to the Call Centre such as Chat and Chat Bot Technology to reduce live agent call handling.

- Hydro One should entertain a chat & chat bot pilot project in the Call Centre
- Each additional 1% of call reduction as a result of Chat & Chat Bot Technology can result in a Benefit (Savings) of $330,000 - $400,000 per year*
- Recent results at utilities demonstrate a call reduction of 1% - 5% when using chat & chat bot technology*
- Estimated Capital investment ranges from $2.5m - $6m*

* ISG experience with other North American utilities and not necessarily Hydro One



Source: CCW Contact Center 2025: A Roadmap

Areas for Potential Improvements – Robotic Process Automation (RPA)

- Hydro One should entertain an RPA pilot in the Call Centre for customer authentication (Billing is already using it) for automating repetitive business processes

- A reduction in work of 10% due to a pilot project can result in a Benefit (Savings) of $450,000 - $600,000 per year*

- Estimated Capital investment ranges from $1m - $2m*

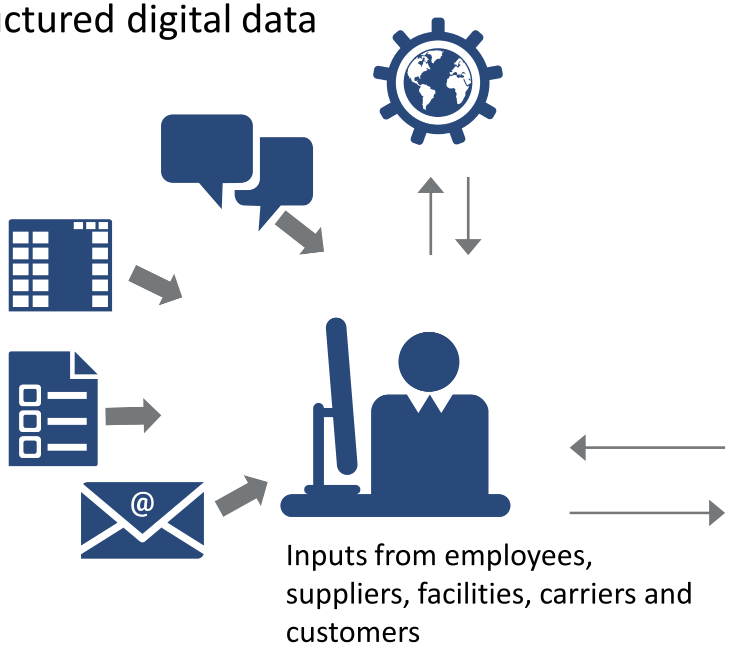
Target processes

Repetitive, routine tasks with

High manual effort (large number of FTEs) and/or…

Benefits that could be derived from enhanced speed, accuracy and availability

- Data aggregation and comparison
- Rules-based decisions, no subjectivity
- Structured digital data



* ISG experience with other North American utilities and not necessarily Hydro One

Areas for Potential Improvements – Voice Biometrics

Many other industries are having success with voice biometrics authenticating customers calling in to the Call Centre.

- Hydro One should entertain a voice biometric option in the Call Centre to reduce time associated with customer authentication

- Other industries (banking, finance, and healthcare) are experiencing a 50 second reduction in AHT by using voice biometrics to authenticate an inbound customer call

- Assuming a conservative 50% of inbound calls using voice biometrics, total Call Centre costs could be reduced by up to 5%, or $1.5m per year*

- Estimated Capital investment ranges from $3m - $5m*

* ISG experience with other North American companies and not necessarily Hydro One – few utilities are doing this today but are beginning to explore it

Appendix – Additional Materials

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Executive Summary

HONI has improved overall costs since re-patriating services from Inergi.

Business Area	2019 HONI Cost	2019 Ontario	2019 Canada	2019 Market Avg
Call Centre	$24.8m	$25.0m	$24.6m	$26.3m
Billing	$5.4m	$6.2	$6.2	$7.1m
Total	$30.2m	$31.2m	$30.8m	$33.4m

Business Area	2019 Market Low	2019 Market High	2019 Market Avg	HONI
Call Centre	$18.0m	$41.4m	$26.3	$24.8m
Billing	$4.8m	$8.1m	$7.1m	$5.4m

Business Area	2014 HONI Cost	2019 HONI Cost	2019 Market Avg
Call Centre		$24.8m	$26.3m
Billing		$5.4m	$7.1m
Total	$37.8m*	$30.2m**	$33.4m

* Outsourced Service Provider costs (Call Centre and Billing were not broken out)
** HONI provided costs (after re-patriation of the Call Centre and Billing services)

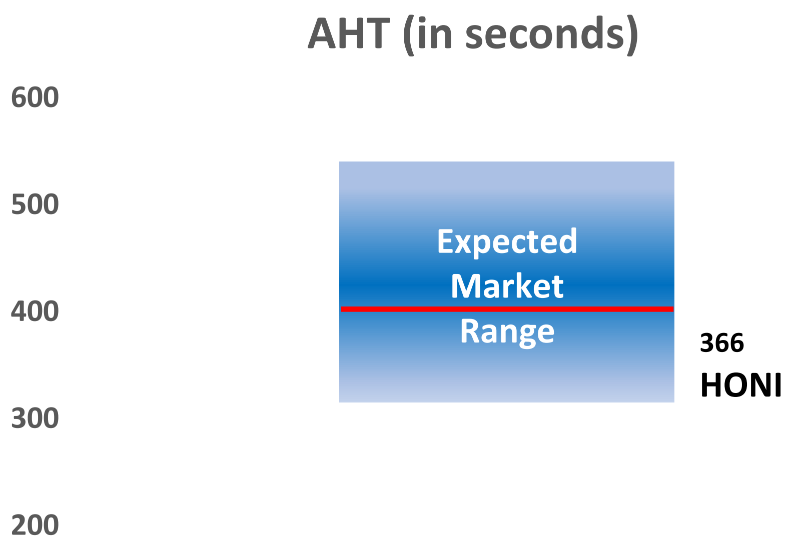
Standard Adjustments

ISG applied some standard adjustments to both Lines of Business to normalize industry costs. Those adjustments are documented below.

- Currency exchange rates – Currency exchange rates applies to personnel costs
  - Since all comparators were North American, currency conversion only applied for U.S. to Canada, which was minimal for the time period in question
  - The adjustment for currency exchange (USD to CAD) in 2019, where applicable, was 1.3269
- Cost of Living Allowance (COLA) or the Consumer Price Index (CPI) – was not utilized since all costs (HONI and comparators) were in the 2019 time period
- Localization – Adjustments were not made to Canadian costs outside the GTA since the resources being benchmarked resided in Markham and London, Ontario
- Unionization – ISG has market data in sufficient quantity from comparators that used unionized operational labour to show that having unionized labour does affect market costs
  - Adjustments were applied to non-unionized comparator costs
  - ISG reviewed salary and benefit figures from companies conducting internal cost benchmarks. Based on values collected from those projects, and comparing overall compensation to those companies with unionized environments, ISG identified the delta as the percentage attributable to unionization
  - The average adjustment for unionization in the 2019 cost benchmark, where applicable, was 38.6%

Average Handle Time (AHT)

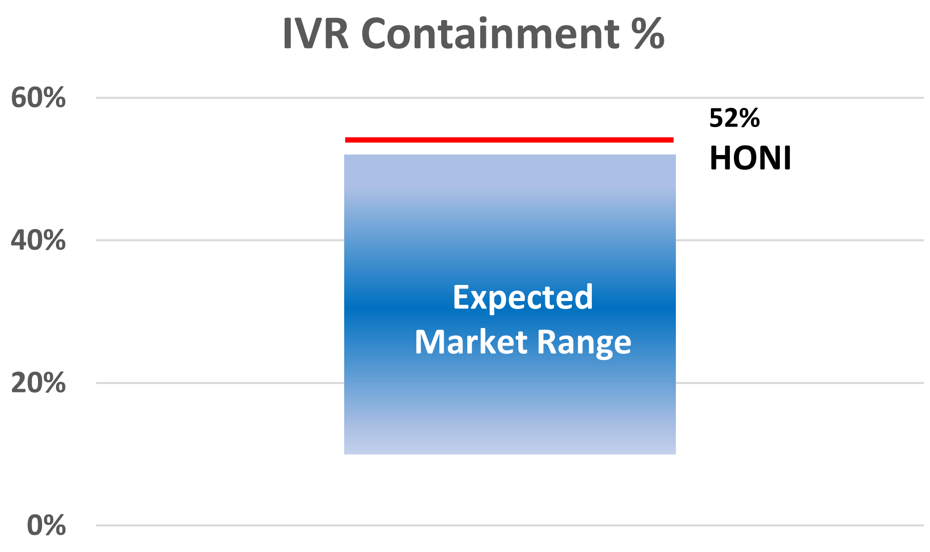
AHT for Hydro One and the Low, High and Average for the Peer Group.



- AHT for Hydro One is below the peer group average of 404 seconds.
- The market ranges from 315 to 540 seconds.

Percentage of IVR Containment

Percentage of IVR Containment for Hydro One and the Low, High and Average for the Peer Group.



- IVR Containment at Hydro One is same as the peer group high.
- The market ranges from 10%-52% with an average of 38.4%

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SMART METER EFFICIENCY REPORT

1.0 INTRODUCTION

Advanced Metering Infrastructure (AMI) refers to all of the components (smart meters, repeaters, regional collectors, Head End System (HES), and related software and firmware) to reliably obtain over-the-air meter readings for accurate customer billing. AMI can also provide a platform for improving customer service and increasing operational efficiency by leveraging data, functionality, and AMI communication networks. Hydro One began deployment of its Advanced Metering Infrastructure (AMI 1.0) in 2007 in accordance with the direction of the Province of Ontario. As set out in the OEB's Filing Requirements, this report documents capital and operating efficiencies that have been realized as a result of deployment and operationalization of its AMI system including both quantitative (where possible) and qualitative descriptions. These efficiencies were made possible by the capabilities of Hydro One's AMI 1.0 system which was implemented close to 15 years ago.

EFFICIENCIES

Theft of Power/Revenue Protection

Theft of power is a safety, operations and revenue issue. Electricity theft can occur in dangerous ways, posing safety risks to the general public, first responders, and Hydro One employees through the threat of fire and electrocution. Theft can also cause strain on the distribution infrastructure resulting in premature equipment failures. Importantly, power theft also puts upward pressure on electricity prices as legitimate customers bear the costs of electricity theft. Reducing electricity theft delivers tangible benefits through increased safety, revenue recovery, and future long-term revenue protection.

Prior to the introduction of AMI, identifying and confirming theft of power was overly time consuming, inefficient, and an expensive manual process. AMI has augmented and increased the efficiency and accuracy of the process through meter tamper detection functionality and making premise-level interval consumption data available for analysis.

While Hydro One cannot reasonably expect to eliminate all electricity theft, AMI has augmented the previous largely manual process. In 2020, through opportunities provided by Hydro One's AMI system (the ability to efficiently identify zero load, reverse flow, and theft) Hydro One identified 193 loss of revenue cases and was able to recover $502,000 through back billing. Significantly, these cases translate into a total of $ 942,000 of revenue protection going forward.

Outage Management

Prior to AMI, meters did not provide any customer outage information. Hydro One was not aware of outages until customers called to report an event. Due to the lack of outage information, field crews engaged in significant travel to identify the location and cause of an outage, increasing personal risk as well as delaying restoration times. During storms, outages are frequently at multiple locations and the risks are even higher due to the need to find the outage under adverse weather conditions.

With AMI, real-time outage notification is provided via "last gasp" functionality of the meters helping to pinpoint some outages more quickly and more specifically, reducing the amount of travel required to patrol the lines under adverse conditions and accelerating the restoration process. More reliable restoration notification through the ability to remotely "ping" meters also allows Hydro One to confirm the outage has been addressed instead of patrolling lines to look for secondary outage issues improving both efficiency and customer service. More specifically, the following outage and restorations efficiencies have been identified:

- **Fault Location** – Outage messages from AMI can be correlated to a common upstream device (e.g. transformer, switch, or recloser). This improves the accuracy of determining the fault location so that field crews can be dispatched closer to the actual fault, improving restoration time, and reducing field crew drive time.
- **Nested Outage** – While field crews are still in the area, dispatchers can confirm that customers have had power restored via AMI restoration messages and meter pings, and

if not, crews can be directed to restore nearby nested outages. This saves return trips to the same area, and improves restoration time.

- **Real Time Updates** – Dispatchers are provided with real time information to better manage a fast paced changing environment, especially in large scale storm scenarios.
- **Restoration Confirmation** – Dispatchers can use AMI restoration messages and meter pings to confirm that an outage has been restored, instead of phoning the customer. This improves customer experience by avoiding a disruptive phone call, and allows confirmation when the customer is not at home (e.g. work day, seasonal property), or asleep late at night. This also improves dispatcher efficiency, especially in larger outages where contacting thousands of customers is not feasible.
- **Outage Verification** – When a customer phones in an outage, the dispatcher can ping their meter to confirm if it is a utility side outage, or a customer side outage (e.g. breaker panel has tripped). This avoids costly trips for the utility to investigate a false positive scenario.

Proactive Power Restoration for Seasonal Customers and Associated Overtime Savings

Prior to the implementation of AMI, Hydro One had no visibility of power outages for unoccupied seasonal residences until reported by customers. Consequently, the traditional cottage opening (May long weekend) resulted in a number of after-hour trouble calls. With AMI, non-communicating seasonal meters can be identified in advance of the long weekend and power restored during normal business hours. This results in the efficient use of resources (avoidance of overtime) and enhanced customer service. As one example where savings were tracked after a storm event in April 2020, 36 cottages with non-communicating meters were visited ahead of the May long weekend and reconnected during normal business hours resulting in about $16,000 in overtime savings.

Reducing Trouble Calls Associated with Electrical Issues "Behind the Meter"

Prior to AMI, Hydro One responded to individual customer outage calls through customer visits, often determining the issues were not associated with the distribution system but rather with an issue with the customer's electrical system "behind the meter". With AMI, Hydro One is able to verify the power problem is behind the meter without dispatching a truck, reducing the number of single customer "truck rolls".

Improved Metering Accuracy and Meter Health Monitoring

Prior to smart metering, although meters operated within their tolerance ranges in accordance with Measurement Canada guidelines, old style electromechanical meters typically slowed down with age due to their moving parts. Slow or failed electromechanical meters may not have been detected until they were sample tested (an event which may not occur for several years). Customers with these slower meters did not pay for all of the energy they consumed and the revenue shortfall was socialized to all customers. Smart meters, unlike electromechanical meters, have no moving parts and are not prone to slowing down, and hence more efficient. Further, meter health monitoring through AMI provides daily statistics to identify defective meters. Ensuring the meter fleet is functioning properly not only protects revenue, but improves customer confidence that their meters are billing reliably and accurately.

Billing Efficiencies

Prior to smart metering, bills were issued based on scheduled manual meter reading, either monthly, bi-monthly, or quarterly. For some customers, bills were calculated as estimates based on historical usage and later trued up when an actual manual meter reading was taken. AMI has reduced the quantity of estimated bills which significantly reduces customer calls regarding this issue. AMI has also increased the efficiency and effectiveness of addressing high bill calls through access to accurate, timely, on-demand information on customer energy use.

AMI also allowed for a more flexible billing window to be introduced providing the ability to shift read dates within a tolerance to efficiently collect actual meter readings for billing where they would otherwise be estimated bills. The flexibilities enabled by the smart meter solution resulted in approximately $1.4 million in avoided 2020 costs that would have otherwise been incurred to meet customer needs for timely and accurate bills.

Improving the Efficiency of Customer Decision Making

Prior to smart metering, the customer's view to their electricity consumption was limited to aggregated monthly electricity usage at best. AMI has provided customers with new opportunities to efficiently monitor their electricity consumption at a significantly more disaggregated level. Hourly electricity consumption data is now made available to customers the day after it is consumed through a convenient internet web portal. The web portal, through built in tools, allows customers to efficiently monitor, analyze, and assess their use for better decision making. AMI has also allowed Hydro One to issue high bill alerts, customized to customer needs and preferences, to efficiently and automatically notify customers if they are trending to use 30 percent more electricity compared to the same period in the previous year. At the end of 2020 Hydro One had 88,000 customers signed up for the high bill alert service and sent out 156,000 "alerts" in 2020 giving customers advanced warning of a higher than normal bill thus allowing them to take appropriate action to adjust consumption to manage the end of the month bill or to properly plan from a budgetary perspective for a higher than normal bill amount.

Customer Service Efficiency

Prior to smart metering, high/low bill checks were performed manually based on monthly customer energy consumption. With smart metering, the clerical effort needed for checking for reasonable consumption is reduced and more effective given the availability of hourly consumption data. Further, the need to perform a "verification" manual reading is greatly reduced. In 2020 material variability in customer consumption resulted in 145,000 high/low bill check exceptions being created of which over 99% were worked without the need to roll a field truck to confirm the meter data accuracy.

Smart Meter Data Analytics

AMI 1.0 has provided the opportunity for additional data analytics for planning. Prior to AMI, meter data was limited to gross monthly customer consumption data. AMI has made available interval customer consumption data to Hydro One in close to real time. This data, within the limits of early generation AMI systems, has provided Hydro One improvements in system planning by utilizing AMI data to assess power system performance, loading patterns and accurate sizing of transformers.

SECTION 3.4 – DSP – CONNECTING DISTRIBUTED ENERGY RESOURCES

3.4.1 OVERVIEW

This schedule summarizes the Distributed Energy Resources (DER) connected to Hydro One's distribution system, and the capacity of the system to connect DER. It also provides information on historical and forecast renewable DER connections and capacity, as required by s. 5.3.4 of the Filing Requirements.

DERs refers to generation facilities including energy storage systems that connect to the distribution system and produce electricity to serve local areas. At the end of 2020, Hydro One had connected over 17,000 DERs for a total of 3,174 MW to its distribution system. The total DERs connected to Hydro One distribution system by type is given in Figure 1.

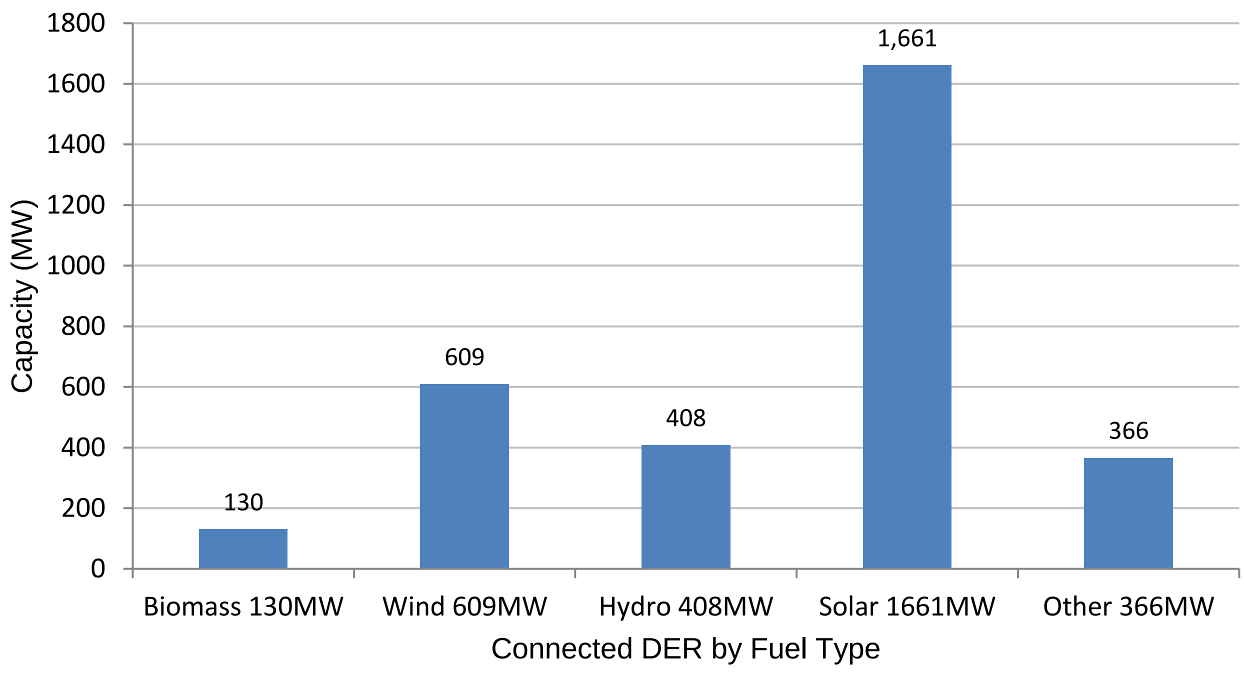

Figure 1: Total Connected Capacity of DER by Type

These DER projects were primarily solar, wind and hydro installations that range in size anywhere from a few kW to several MW. In recent years, Hydro One has seen an increase in the connection of Battery Energy Storage Systems (BESS). A BESS acts like a load while it is charging from the grid, and acts like a generator when it is discharging.

Hydro One's strategy for DER connections is to meet its distribution license requirements to connect generators that meet the principles set out in the DSC.

3.4.2 RENEWABLE APPLICATIONS

DER activity in Ontario has shifted from retail generators participating in historical IESO procurement programs to behind-the-meter (BTM) Load Displacement Generators participating in the IESO's Industrial Conservation Initiative (ICI) program and Ontario Net Metering program. Previously, the dominant source of renewable DER applications had been the Feed-in Tariff (FIT) program which was terminated in 2017. The Net Metering program is still limited to renewable DER, and remains active and regulated by Ontario Regulation 541/05 (O. Reg. 541/05).

Currently, the majority of applications received under the Net Metering program are less than 500 kW but Hydro One expects some large projects in the future as the cost of solar installations is continuously decreasing. Hydro One continues to apply the DSC rules related to Renewable projects by funding a portion of the expansion cost (up to $90,000/MW) and 100% of Renewable Enabling Improvement (REI) investments.

The IESO ICI program allows large distribution connected load customers to reduce their Global Adjustment cost by reducing their peak during the five Ontario peaks. The majority of these projects are non-renewable and range in size from 500 kW to 20 MW depending on size of the load facility. Since 2018, the DER applications received by Hydro One have been primarily combined heat and power/co-generation, natural gas, diesel and BESS. The cost for connecting these non-renewable energy projects to Hydro One distribution system is 100% recoverable from the DER customers.

3.4.3 CONNECTION FORECAST

Hydro One classifies DER into four categories for planning purposes:

1. Capacity Allocation Required (CA), this includes large DERs, mid-sized DERs and small embedded DERs that are not capacity allocation exempt;
2. Capacity Allocation Exempt (CAE);
3. Capacity Allocation Exempt generators that are Net-Metered (CAE-NM); and
4. Micro embedded (10 kW or less) – including Micro-FIT.

The vast majority of existing DERs are renewable and consist of small micro-FIT projects. These units possess a generation capacity of 10 kW or less per unit and comprise less than 10% of the capacity of the DER connections on the system. Hydro One connected 15,628 micro embedded projects with a total capacity of 140.1 MW of generation as of the end of 2020. Since 2010, Hydro One has connected over 1,498 DERs with generation capacity greater than 10 kW, with a combined capacity of approximately 2490 MW.[1] The majority of these DERs are renewable and have been connected under IESO programs.[2] Table 1 details the additions to the system in terms of quantity and capacity of DER projects from each of the four segments.

[1] The sum of CAR, CAE, and CAE-NM connections, as set out in Table 1.
[2] Relevant IESO programs are RESOP, FIT, LRP, HESOP, CHPSOP and HCI.

Table 1 - DER Projects Connected from 2010-2020 and Committed in 2021-2022

		Connected												Committed	
Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total	2021	2022
CAR	Projects	40	24	25	49	60	62	17	11	15	24	22	**349**	32	0
	Capacity (MW)	315.5	159.5	220.9	342.4	468.1	326.2	107.3	53.0	57.5	82.2	103.7	**2236.3**	108.9	0
CAE	Projects	1	75	141	102	142	182	111	81	75	81	42	**1033**	8	0
	Capacity (MW)	0.5	11.6	22.8	18.6	24.4	34.4	31.3	23.9	21.7	34.0	19.4	**242.5**	2.2	0
CAE Net Metered	Projects	1	0	2	1	1	6	8	13	25	39	17	**113**	31	0
	Capacity (MW)	0.1	0.0	0.2	0.2	0.0	0.3	0.5	1.2	2.3	3.5	2.2	**10.5**	3.8	0
Micro Embedded	Projects	2462	5389	2353	1489	617	584	701	958	759	178	138	**15628**	85	4
	Capacity (MW)	21.5	49.6	21.9	13.2	5.4	5.3	6.4	8.0	6.1	1.5	1.2	**140.1**	0.7	0.03
Total	Projects	2504	5488	2521	1641	820	834	837	1063	874	322	219	**17123**	156	4
	Capacity (MW)	337.6	220.7	265.9	374.5	497.9	366.2	145.4	86.1	87.5	121.1	126.5	**2629.4***	115.7	0.03

**Approximately 502 MW of DER were connected prior to 2010.*

The details of connected projects versus forecast provided for the period 2017-2020 in Hydro One's last rate application are provided in Table 2.

Table 2 - The difference in the Number of DER Forecast vs Actual Connected during 2017-2020

Project Category	Number of Projects		
	Connected	Forecast	Difference
CAR	72	24	(+) 48
CAE	324	730	(-) 406
CAE Net Metered	93	897	(-) 804
Micro Embedded	2,033	1,100	(+) 933

The reasons for variation in forecast versus the actual connected projects under various categories during the period 2017-2020 include the following:

- The increase in CAR projects is due to customers participating in the IESO ICI program in order to reduce their global adjustment cost. This program was expanded in 2017 to include smaller load customers, resulting in an increase in large DER connections.
- The IESO cancelled all FIT 2, 3, 4, and 5 contracts where it had not issued Notice to Proceed after the receipt of a directive from Ministry of Energy, Northern Development

and Mines (the Ministry) issued on July 13, 2018. 544 CAE FIT projects were withdrawn, primarily due to the cancellation of their contracts, resulting in much lower volume of connected projects than forecasted.

- Due to the end of the FIT program and a proposed amendment to Ontario Net Metering Regulation O. Reg. 541/05 by the Ministry in 2017, Hydro One was expecting a large number of CAE Net Metered applications starting 2018. Additionally in 2017 Hydro One received a very large number of pre-connection consultations for net metering projects from one developer with an expectation of additional requests. However, the additional requests were not made and the developer never proceeded with formal applications for these requests.
- MicroFIT project connections were trending lower in 2016, but unexpectedly rebounded in 2017 after the end of the FIT program was announced. Micro Embedded connections have dropped dramatically since the last microFIT projects were connected in about 2018. Present micro-embedded connections are almost exclusively participating in the net-metering program.

Currently, Hydro One is receiving a moderate number of DER applications under the IESO ICI program. These DER applications for the purpose of load displacement or “peak shaving” are non-renewable and connect behind the meter to reduce the customer’s global adjustment cost. The only active renewable energy program in place in the province of Ontario is the Net Metering program, which is regulated by O. Reg. 541/05. Based on these two programs, the number of projects forecast for 2021 to 2027 is shown in the Table 3.

Table 3 - Number of DER Forecast for 2021-2027

		Forecast Number						
Year		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Non Renewable Energy Projects	**> 10 kW**	20	15	15	15	15	15	15
	≤ 10 kW	5	5	5	5	5	5	5
Renewable Energy Projects	**> 10 kW**	50	50	50	50	50	50	50
	≤ 10 kW	150	150	150	150	150	150	150

The forecast of non-renewable energy projects consist of combined heat and power (CHP), energy storage systems, natural gas, diesel etc. connecting behind the meter for the purpose of load displacement / peak shaving. The majority of energy storage systems are lithium-ion batteries as their prices continue to drop. The majority of forecasted renewable energy projects would be solar and expected to connect under the Ontario Net Metering program.

Net-metering applications are expected to occur throughout Hydro One's service territory. Hydro One does not have any information that would suggest a specific geographic concentration of activity.

3.4.4 CAPACITY AND CONSTRAINTS

The Hydro One distribution system is primarily radial in design, with limited transfer capability in the supply to customers. The system was designed with a forward power flow direction with the supply coming from the transmission system flowing downstream to the distribution customers. Hydro One provides information on station capacity in order to provide potential DER customers with assistance in determining a suitable location for their DER projects. The available capacity is published on Hydro One's website as the Hydro One List of Station Capacity and is updated every month. Additionally, Hydro One has made available a calculator tool to enable customers to easily determine the remaining DER capacity at their location of interest. It is expected that the Hydro One distribution system will have ample ability to accommodate the forecasted DER levels at a provincial scale. There are regional constraints that will affect DER developers, as described below.

The amount of DER capacity available for connection to Hydro One's distribution system is constrained by thermal and short circuit limits. These constraints are due to a variety of engineering factors, including but not limited to:

- Equipment ratings
- Reverse power flow constraints
- Supply feeder current ratings
- Power Quality

- Remaining short circuit capacity at upstream stations
- Operability

There are a number of Hydro One distribution stations that do not have capacity to connect DER. There is also a significant number of Hydro One distribution stations which are restricted due to thermal constraints on the upstream transmission assets. The list of restricted Hydro One distribution stations and upstream TS is provided in Table 4.

Table 4 - The list of restricted DS and TS with type of restriction

Station Name	Type of Restriction
Calstock HVDS	Thermal
Chapleau HVDS	Thermal
Fauquier HVDS	Thermal
Laforest Road HVDS	Thermal
Smooth Rock Falls HVDS	Thermal
Barwick TS	Thermal
Chesterville TS	Thermal
Cobden TS	Thermal
Pembroke TS	Thermal
Wallace TS	Thermal
Morrisburg TS	Thermal
Kleinburg TS	Short Circuit
Lambton TS	Short Circuit
Norfolk TS	Short Circuit
Wanstead TS	Short Circuit
Cumberland HVDS	Short Circuit
Manotick HVDS	Short Circuit
Sharbot HVDS	Short Circuit

A local distributor embedded within Hydro One's distribution system that is seeking to connect a new DER to their distribution system would need to account for the same factors as a DER connecting directly to Hydro One's distribution system. The equipment ratings, the power flow and short circuit impacts on the embedded distributor's and Hydro One systems would need to be studied for each DER application. Upgrades may be necessary at both distribution and/or transmission stations to mitigate these factors.

3.4.5 REG INVESTMENTS

Hydro One's Renewable Energy Generation (REG) investments are related to enabling specific applications to connect REG to Hydro One's distribution system. The investments represent regulatory obligations for renewable enabling improvements and the renewable energy expansion cost cap.

In the past, the FIT program was the dominant source of opportunity for REG. Consultation with the IESO during the FIT program allowed Hydro One and IESO to validate the volume of expected REG in Hydro One territory. No FIT contracts were issued after 2017, and consultation with the IESO is no longer necessary to validate REG investments. REG investments today are largely a result of applications to the net-metering program.

Hydro One has not made any REG investments in the DSP for the sole purpose of creating future REG capacity. Because the major impacts of DER interconnections are extremely localized, it is very difficult to predict where a REG investment will be prudent. Hydro One participates in the IESO Regional Planning Process and therefore has an opportunity to coordinate any plans that might result in additional REG capacity. Hydro One coordinates REG investments with other LDCs when a DER requests a connection to a feeder which is shared between Hydro One and the other LDC.

DSP Section 3.4, Attachment 1 is a letter from Hydro One's Regional Planning Group to Hydro One's Distribution Asset Management which summarizes Hydro One's participation in the IESO regional planning activities.

The following attachment(s) are provided as part of this section:

- Attachment 1 - Hydro One Letter Summarizing Participation in IESO Regional Planning Activities

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May 17, 2021

Mr. Peter Faltaous
Director, Distribution Asset Management
Hydro One Distribution
Toronto

Subject: Regional Planning Status

As per your request, this Planning Status letter is provided to meet one of the requirements of your upcoming Rate Application to the Ontario Energy Board (OEB).

As you are aware, the province of Ontario is divided into 21 Regions for the purpose of Regional Planning (RP), a map of Ontario showing the 21 Regions and the list of Local Distribution Companies (LDCs) in each of the Region are attached as Appendix A and B respectively.

Hydro One Distribution (HOD) is an LDC in all regions across the province, except for North of Moosonee, and Hydro One Networks Inc. (Hydro One) is the lead transmitter for 20 of the regions. The table below provides list of all 21 regions.

Regional Planning Regions

Burlington to Nanticoke	Northwest Ontario	Chatham/Lambton/Sarnia
Greater Ottawa	Windsor-Essex	Greater Bruce/Huron
GTA East	East Lake Superior	Niagara
GTA North	London Area	North/East of Sudbury
GTA West	Peterborough to Kingston	Renfrew
KWCG	South Georgian Bay/Muskoka	St. Lawrence
Toronto	Sudbury/Algoma	North of Moosonee*

*This region is not within Hydro One's territory.

This letter confirms that the first cycle of RP has been completed for all 21 regions. The second cycle of regional planning is currently underway, with Needs Assessment ("NA") for fifteen (16) regions and Regional Infrastructure Plan ("RIP") for five (5) regions completed to date. Each region's current status and corresponding reports are published online and can be accessed through Hydro One's Regional Planning website[1]. The regional planning status for the individual regions is discussed in the appropriate section.

Please note that the Regional Planning didn't identify / address any Renewable Energy Generation (REG) specific investments mainly because such investments are more local in nature and are being address directly by the

[1] https://www.hydroone.com/about/corporate-information/regional-plans

LDCs as part of their Distribution Planning activities.

Burlington to Nanticoke

Burlington to Nanticoke Region comprises the municipalities of Burlington, Hamilton, Oakville, Brantford, and the Counties of Brant, Haldimand, and Norfolk. Within the context of regional planning, the region is divided into four sub-regions: Brant, Bronte, Greater Hamilton, and Caledonia-Norfolk sub-regions.

Since the previous regional planning cycle, the following projects have been completed and/or underway:

- Replacement of EOL Equipment at Bronte TS, Horning TS, Mohawk TS
- Bronte TS: 115 kV B7/B8 Transmission line capacity
- Brant Switching Station: 115 kV B12BL/ B13BL Transmission line capacity
- Cumberland TS: Power Factor Correction

None of the projects listed above are expected to have any cost allocation to HOD.

The second cycle of RIP was completed and published in October 2019 (Appendix C). Based on the assessment, there are several major infrastructure investments recommended by Hydro One in the near-term planning horizon. One of the projects at Dundas TS (as indicated below) has cost allocation to HOD. The projects include but not limited to following:

- Refurbishment of EOL Line sections
- Replacing EOL equipment
- Reconfiguring 2 DESNs to single DESN at Kenilworth TS and Elgin TS
- Reconfiguring 3 DESNs to 2 DESN at Gage TS
- Installation of Capacitor Banks at Norfolk TS

Dundas TS: Load Transfer – Dundas TS has two DESN units; one of the two units has loads in excess of its supply capacity while the other DESN has spare capacity to accommodate these excess loads. The recommended plan is for HOD to balance the load between the two Dundas TS DESNs. This requires HOD to transfer excess load from Dundas TS to Dundas TS #2 by utilizing two new additional breaker positions at an estimated cost of $2 million. It is estimated that HOD will have to invest approximately $9 million in distribution infrastructure to fully implement this plan. This project is currently planned to be completed by 2021.Hydro One Distribution will be required to make capital contribution for two new additional feeder breaker position at Dundas TS # 2 in accordance with Transmission System Code.

The mid and long-term needs in the region will be assessed in the next regional planning cycle. Some of the needs include:

- EOL Equipment (i.e. cables, switchgears etc.) at several stations in the region
- Norfolk area supply capacity
- EOL 230 kV auto-transformers and DESN transformers at Beach TS and Burlington TS, which will be assessed as part of the Middleport Bulk Study by the IESO in coordination with Hydro One

The above projects are expected to improve the overall reliability performance in the region.

None of the upcoming projects (in the mid and long-term) are expected to have any cost implication to HOD.

Greater Ottawa

Greater Ottawa Region covers the municipalities bordering the Ottawa River from Stewartville in the West to Hawkesbury in the East and North of Highway 43. For the purpose of regional planning, the region is divided into two sub-regions: Ottawa Area and Outer Ottawa.

The first cycle RIP for the Greater Ottawa Region was published in December 2015.

The second cycle Needs Assessment report was completed and published in June 2018. The second cycle IRRP by IESO was completed in March 2020. The Hydro One led RIP will be completed and the report to be published in Q1 2021 (Appendix C).

Based on the assessments, the major infrastructure needs and or investments recommended by Hydro One in the near and mid term planning for the two sub-regions are provided below:

- Replacementof EOL Equipment at Lincoln Heights TS, Longueuil TS, Riverdale TS, Albion TS, Russell TS, Bilberry Creek TS, Merivale TS
- Overbrook Station Capacity
- Transformation Capacity in South East Ottawa
- Build Hawkesbury MTS
- Install two new LV breakers at Bilberry Creek TS

None of the projects listed above are expected to have any cost implication to HOD.

The above projects are expected to improve the overall reliability performance in the region. The future system capacity need for Greater Ottawa will be studied during the next phases of regional planning.

GTA North

The GTA North Region is approximately bounded by the Regional Municipality of York, and also includes parts of the Cities of Toronto, Brampton, and Mississauga. For the purpose of regional planning, the region was divided into two sub-regions: York and Western sub-regions.

Since the previous regional planning cycle, the following projects have been completed with no expected cost allocation to HOD.

- Vaughan #4 MTS (completed in 2017)
- Holland breakers, disconnect switches and special protection scheme (completed in 2017)
- Parkway belt switches at Grainger Jct. (completed in 2018)

The second cycle RIP has been completed and the report was published by Hydro One in October 2020 (Appendix C). Based on the assessment, there are several major infrastructure investments recommended by Hydro One in the near and mid-term planning horizon intended to improve the overall reliability of the region. None of the projects below are expected to have any cost implication to HOD.

- Building new stations (i.e. Markham #5 MTS, Vaughan #5 MTS, Northern York Station) to meet transformation capacity

- Replacement of EOL replacement at Woodbridge TS
- Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS

None of the projects listed above are expected to have any cost implication to HOD
The above projects are expected to improve the overall reliability performance in the region. The future system needs for GTA North will be studied during the next phases of regional planning.

GTA West

The GTA West Region covers the Regional Municipalities of Halton and Peel, and comprises the municipalities of Brampton, South Caledon, Halton Hills, Mississauga, Milton, Oakville and parts of Burlington.

The second cycle of Regional Planning for the GTA West Region is currently underway. The Needs Assessment Report was completed and published in May 2019 (Appendix C). The IRRP is currently underway, and is expected to be completed by Q1 2021.

Based on the assessment, there are several major infrastructure investments recommended by Hydro One in the near, mid and long-term planning horizon with no cost implication to HOD. The projects include but not limited to following:

- Replacement of end of life component at several stations
- Building of Halton TS # 2 to address overloading at Halton TS (T3/T4) DESN based on latest load forecast

The following needs require further regional coordination in the next phase after the completion of NA:

- Overloading circuits,
- SupplySecurity & supply Restoration needs,
- EOL replacementof Palermo TS transformers T3/T4 and
- GTA West Transmission corridor

These projects are expected to improve the overall reliability performance in the region, however, none of these projects are expected to have any cost implication to HOD. The needs stated in the NA will be further discussed in the upcoming IRRP and RIP.

Kitchener-Waterloo-Cambridge-Guelph Region

The KWCG region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington Counties and the Townships of Wellesley, Woolwich, Wilmont and North Dumfries.

The following transmission projects were completed by Hydro One to address near-term supply needs that were recommended in the first cycle RIP (Appendix C) with no expected cost allocation to HOD:

- The Guelph Area Transmission Refurbishment Project (GATR), placed into service since Q4 2016.
- The switching facilities work at Galt Junction to improve supply reliability for the Cambridge-Kitchener 230 kV Sub-system, placed into service in Oct 2017.

The second cycle Needs Assessment phase was completed and the report was published in December 2018.The IRRP phase will be completed and the report to be published by IESO in Q1 2021. The second cycle RIP will be completed subsequently.

The Needs Assessment has identified new needs in the region. The near and mid-term needs mainly address the aging infrastructure:

- EOL Transformer replacement at Campbell TS, Hanlon TS, Cedar TS and Preston TS
- Circuit upgrade: 115 kV B5C/ B6C, D7F/D9F and 230 kV D6V/ D7V
- Detweiler TS -Auto T2 &T4

The above projects are expected to improve the overall reliability performance in the region and are not expected to have any cost implication to HOD for the projects listed above. The needs identified in the NA will be further discussed in the upcoming IRRP and RIP.

Toronto

The Toronto (formerly referred to as Metro Toronto) Region comprises the area within the municipal boundary of the City of Toronto. In the first regional planning cycle, the region was divided into two sub-regions: Central Toronto and Northern Toronto sub-regions. In the second Regional Planning cycle, the Toronto Region was assessed as a whole and no sub-regions were created.

Since the previous regional planning cycle, the following projects have been completed, none of which had any cost contribution to HOD:

- Midtown Transmission Reinforcement Project (completed in 2016)
- Clare R. Copeland 115 kV Switching Station and Copeland MTS (completed in 2019)
- Manby SPS Load Rejection (L/R) Scheme (completion in 2019)

The second cycle RIP was completed in March 2020 (Appendix C). Based on the assessment, the major infrastructure investments recommended by Hydro One in the near and mid-term planning horizon are listed below:

- Replace EOL equipment at Main TS, Manby TS, Bermondsey TS and John TS
- Refurbish EOL line sections (i.e. H1L/H3L/ H6LC/H8LC section, L9C/L12C section)
- Replace underground cables at Esplanade TS and Terauley TS
- Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS

The above projects are expected to improve the overall reliability performance in the region, however none of these projects are expected to have any cost implication to HOD. The future system needs for Toronto will be studied during the next phases of regional planning.

Windsor-Essex

The Windsor-Essex region includes the most southerly portion of Ontario, extending from Chatham southwest to Windsor. It consists of the City of Windsor, the Municipality of Leamington, the Town of Amherstberg, the Town of Essex, the Town of Kingsville, the Town of Lakeshore, the Town of LaSalle, the Town of Tecumseh, and the Township of Pelee, as well as the western portion of the Municipality of Chatham-Kent.

Since the previous regional planning cycle, the projects listed below have been completed and or underway. The project at Leamington TS (as indicated below) had cost allocation to HOD.

- Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017)
- Malden TS breakers replacement (I/S 2018): two 27.6 kV feeder breakers have been replaced.
- Supply to Essex County Transmission Reinforcement (I/S 2017): Build new 13 km double-circuit 230 kV transmission lines to Leamington area tapped to existing C21J/C22J circuits, and new 75/100/125 MVA Leamington TS and its distribution feeders.
- Reconfiguration of 230 kV and 115 kV circuits and 27.6 kV feeders at Keith TS to accommodate the construction of Gordie Howe International Bridge (I/S 2019)
- **Leamington TS expansion**: Build the second 75/100/125 MVA DESN at Leamington TS (I/S 2019)
- Kingsville TS transformers replacement (in progress, I/S 2022): Transformers T2 and T4 have been replaced with 50/83 MVA T6 in 2018. Transformers T1 and T3 replacement is underway.
- Keith TS autotransformers replacement (in progress, I/S 2023): 125 MVA autotransformers T11 and T12 will be replaced by 250 MVA units.
- Tilbury TS decommissioning (in progress, I/S 2024): Decommissioning of station due to end-of-life and transfer serviced load to Tilbury West DS supply.
- Keith TS transformer T1 decommissioning (expected I/S 2024).

HOD will pay capital contribution as per the TSC for the expansion work at Leamington TS.

The second cycle RIP was completed and the report was published by Hydro One in March 2020 (Appendix C). The major infrastructure investments recommended by Hydro One in the near-term planning horizon are:

- Replace Lauzon TS T5 & T6 transformers replacement with larger 75/125 MVA units
- Upgrading station capacity at Kent TS
- **Build new switching station at Leamington Junction (Lakeshore TS), and new DESN station (South Middle Road TS)**
- Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS

HOD will have cost allocation to complete the new DESNs at South Middle Road TS. Each of the two DESNs at South Middle Road TS will consist of 2 x 75/100/125 MVA, 230/27.6 – 27.6 kV power transformers, twelve LV feeder positions and 2 LV capacitor banks, plus required switchgear.

Hydro One has completed necessary engagement activities and Class Environmental Assessment work for the establishment of the two stations. Hydro One obtained EA approval for the stations with the submission of the final Environmental Study Report to the Ministry of the Environment, Conservation and Parks, in January 2020. Construction is planned to commence in Q3 2020 for both Lakeshore TS and the first of the two DESNs at South Middle Road TS, and both facilities are planned to be in service in Q2 2022. The second DESN at South Middle Road TS is planned to be in service in Q3 2025.

The above projects are expected to improve the overall reliability performance in the region. The future system need for Windsor-Essex region will be studied during the next phases of the regional planning.

GTA East

GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, and parts of Clarington and other parts of Durham Region.

Since the previous regional planning cycle, the following project have been completed:

- **Enfield TS**: 75/100/125 MVA transformation capacity in Oshawa-Clarington sub-region (Completed in 2019)

As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located adjacent to Clarington TS and will supply OPUC through four (4) feeders and Hydro One Dx through two (2) feeders. The station went in-service in March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS.

For the Enfield TS project, HOD was required to make capital contribution according to TSC.

The second cycle RIP was completed and report published in February 2020 (Appendix C). Based on the assessment, the major infrastructure investments recommended by Hydro One over near- and mid-term are as follows:

- Build Seaton MTS to increase capacity in Pickering-Ajay-Whitby Sub-region
- Replace 230 kV and 500 kV ABCB at Cherrywood TS
- Refurbish 44 kV DESN switchyard at Cherrywood TS
- Refurbishment work at Wilson TS

The above projects are expected to improve the overall reliability performance in the region, however none of the projects are expected to have any cost implication for HOD. The future system need for GTA East will be studied during the next phases of the regional planning.

Northwest Ontario

The Northwest Ontario region encompasses a large geographic area, stretching from the town of Marathon to the western and northern borders of the province, with diverse characteristics. This region is divided into four sub-regions for regional planning purposes: North of Dryden, Greenstone-Marathon, Thunder Bay and West of Thunder Bay.

Since the previous regional planning cycle, the following projects have been completed and/or underway, with no expected cost allocation to HOD:

- The new 230kV Watay connection between Pickle Lake Switching Station ("SS") and Dinorwic Junction ("Jct") will provide relief to the capacity constraint on E1C by 2021
- The forecasted load growth at Kenora MTS is anticipated to reach 23MW by year 2027, which is also near the station's 10-Day Limited Time Rating ("LTR").

The second cycle Needs Assessment was completed and the report was published in July 2020 (Appendix C). Scoping Assessment was triggered in October 2020, and it is anticipated for completion in Q1 2021. Based on the recent NA, new needs identified in the region include but not limited to:

- Aging Infrastructure at several station

- Lakehead TS Capacity Need
- Marathon TS Capacity Need
- **Sapawe DS** – This station is a 115/12.5kV distribution station owned by Hydro One Distribution. The station has a Winter Planned Loading Limit (PLL) of 4.30MW and a Summer PLL of 3.42MW (assuming 0.9 power factor), and its load growth is anticipated to reach these levels by year 2028 and 2026 respectively. Hydro One Distribution will take the lead to look into this need in co-ordination with Hydro One Transmission as part of the Distribution Planning.

There will be cost implications for HOD for the Sapawe DS project consistent with the requirements set in the TSC. The needs identified in the NA will be further discussed in the upcoming IRRP and RIP.

East Lake Superior (ELS)

The ELS Region includes all of Hydro One Sault Ste. Marie's 560km of high-voltage transmission lines as well as ties to the rest of the provincial grid at Wawa TS in the northwest and Mississagi TS in the northeast. The region also includes Hydro One's 115kV W2C circuit supplying the Town of Chapleau from Wawa TS. During the first cycle of regional planning (led by the former Great Lakes Power Transmission), only local needs were identified and they did not require further regional coordination.

Since the previous regional planning cycle, the following projects have been completed, underway and/or on hold:

- Transmission Supply Capacity of Hollingsworth TS / Anjigami TS Transformers
- Transmission Supply Capacity of No. 1 Algoma Circuit
- Transmission Supply Reliability at Echo River TS

The second cycle of Regional Planning was initiated by Hydro One in 2019, with the NA report published in June 2019 (Appendix C) and the IRRP is currently underway, and is expected to be completed in Q1 2021. Based on the Needs Assessment, following major infrastructure investments are recommended by Hydro One over the near- and mid-term:

- Overloading of 230/115 kV Autotransformers at Third Line TS – to be addressed in Scoping Assessments
- Load restoration need at Andrew TS, Batchawana TS and Goulais TS
- Replacement of Aging Infrastructures at several stations

None of these projects above are expected to have any cost implication to HOD.

The above projects are expected to improve the overall reliability performance in the region. The needs identified in the NA will be further discussed in the upcoming IRRP and RIP.

London Area

The London Area includes the Cities of Woodstock, London and St. Thomas as well as the Counties of Middlesex, Elgin and Oxford. The London Area region was divided into five sub-regions based on electrical supply boundaries for further regional planning purposes:

The RIP for the region was completed in August 2017. Based on the previous assessment the following needs were identified:

- Load Restoration for loss of M31W/M32W or loss of W36/W37
- Voltage Constraint at Tillsonburg TS
- Thermal constraint on line W8T
- **Delivery point performance at Tillsonburg TS: Aylmer-Tillsonburg Project**

The customer delivery points serving Tillsonburg Hydro and HONI distribution at Tillsonburg TS is not meeting CDPPS requirements with regards to frequency of interruptions. A number of options were explored to address the delivery point performance need. It was agreed that reversing the existing normal operating points at Cranberry Junction will be the most cost-effective option. Upon the completion of the Aylmer-Tillsonburg project, Tillsonburg TS will be normally supplied by W3T/W4T/T11T while Aylmer TS will remain normally supplied by W8T. This project is currently underway with expected in-service date of Q2 2022.

There will be cost allocation to HOD for the Aylmer-Tillsonburg project.

The second cycle NA was completed and report published in May 2020 (Appendix C). Based on the findings of the Needs Assessment, Hydro One recommends that load restoration need following the loss of W36 and W37 should be further assessed as part of Local Planning by Hydro One.

The future system need for London Area will be studied during the next phases of the regional planning.

Peterborough to Kingston

The Peterborough to Kingston Region includes the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, Frontenac County on the East and Lake Ontario on the South. The region includes Frontenac County, Hasting County, Northhumberland County, Peterborough County, and Prince Edward County and related municipalities.

Since the previous regional planning cycle:

- The load supplied by Gardiner TS DESN 1 T1/T2 exceeded its summer 10 day Limited Time Rating (LTR) of 125 MW. As recommended in the previous NA, Hydro One Distribution has completed the transfer of load from DESN 1 to lightly loaded DESN 2 with excess capacity resulting in a load relief for Gardiner TS DESN 1.

The second cycle of Needs Assessment was completed and report was published in February 2020 (Appendix C). The second cycle IRRP is currently underway with expected completion date of Q4 2021. The RIP will follow. Based on the assessment, the major infrastructure investments recommended by Hydro One over near- and mid-term are:

- Replacement of EOL equipment at Lennox TS, Port Hope TS, Havelock TS and Belleville TS
- Line/ Station capacity needs at Frontenac TS, Gardiner TS and Belleville TS

Frontenac TS Over loading need shall be managed by Hydro One Transmission by coordinating with Hydro One Distribution and Kingston Hydro to undertake distribution load transfers between Gardiner TS and Frontenac TS over the near term. There is no expected cost allocation to HOD for this project.

The needs identified in the NA will be further discussed in the upcoming RIP.

South Georgian Bay/Muskoka

The geographical area of the South Georgian Bay/Muskoka Region is the area roughly bordered by West Nippising on the North-West, the Algonquin Provincial Park on the Northeast, Scugog on the South, Erin on the South-West and Grey Highlands on the West.

The second cycle Needs Assessment of this region was completed and report was published in April 2020 (Appendix C). The Scoping Assessment is currently in progress with expected completion date of Q4 2020.

Based on the assessment, the major transmission and distribution infrastructure investments planned for the South Georgian Bay/Muskoka Region over the near and mid-term, as identified in the various phases of the regional planning process are:

- Replacement of 115-44kV transformers at Barrie TS, uprating 115kV circuits to 230kV, adding additional feeders to Barrie DESN
- Replacement of 230-44kV transformers and possible rebuild of low voltage switchyard at Minden TS
- Installation of sectionalizing motorized disconnect switches on circuits M6E/M7E (at Orillia TS)
- **Build new 44 kV sub-transmission line between Parry Sound TS and Muskoka TS**
- Replacement of 230/44 kV transformers at Parry Sound TS
- Replacement of dual windings 230-44/27.6kV transformers (T1 and T2) and associated low voltage equipment at Orangeville TS

Hydro One Distribution currently has a number of on-going maintenance and outage mitigation initiatives on the feeder lines (out of Parry Sound TS and Muskoka TS) to reduce frequent outages. Another option to mitigate outages on the 44 kV is to build new distribution lines from Bracebridge TS, and transfer some load over to Bracebridge TS. A cost-benefit/responsibility analysis will be considered by Hydro One Distribution, and other LDCs to improve reliability performance of the Parry Sound/Muskoka 44 kV sub-transmission system.

The above projects are expected to improve the overall reliability performance in the region. The needs identified in the NA will be further discussed in the upcoming RIP.

Sudbury/ Algoma

The Sudbury/Algoma region includes the municipalities of Greater Sudbury and Espanola and surrounding areas. There are municipal LDCs serving each of those municipalities and Hydro One Distribution serves the remainder of the Region. The area is supplied from transformer stations Clarabelle TS, Coniston TS, Elliot Lake TS, Larchwood TS, Manitoulin TS and Martindale TS.

Based on the previous assessment, the following the major transmission and distribution infrastructure investments planned for the Sudbury/ Algoma Region over the near and mid-term, as identified in the various phases of the regional planning process are:

- EOL equipment replacement at Coniston TS, Espanola TS (I/S 2016), Martindale TS
- Voltage Regulation at Manitoulin TS

The second cycle of Needs Assessment was completed in June 2020 (Appendix C). Based on the N/A, the following needs were observed:

- Manitoulin TS - The station transformer capacity is restricted by a setting of a series limiting component.

- Martindale TS – Address supply capacity need

None of the above needs/projects are expected to have any cost allocation to HOD. The needs identified in the NA will be further discussed in the upcoming IRRP and RIP.

Chatham/Lambton/Sarnia

The Chatham-Lambton-Sarnia region is located to the west of the Greater Toronto Area in southwestern Ontario. The region includes the municipalities of Lambton Shores and Chatham-Kent. It also includes the Townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick and the Villages of Oil Springs and Point Edward.

Hydro One developed and published a RIP in August 2017 (Appendix C). The next cycle of Regional Planning for this region is currently anticipated to commence in 2021.

The Study Team determined that no further regional coordination is required. However, several needs that are local in nature such as

- **Thermal overload of transformer T3 at Kent TS** - Based on the load forecast, there is sufficient transfer capability on the existing system to mitigate the potential transformer overload at Kent TS over the ten year study period from 2017 to 2026. Therefore Hydro One Distribution, Entegrus Inc. and Hydro One Transmission agreed that no further action is required at this time.

Therefore, there is no expected cost allocation to HOD at this point.

The future system need for Chatham/Lambton/Sarnia will be studied during the next phases of the regional planning.

Greater Bruce/ Huron

The Greater Bruce/Huron area is located to the west of the Kitchener-Waterloo region in southwestern Ontario. The region includes the municipalities of Arran–Elderslie, Brockton, Kincardine, Northern Bruce Peninsula and South Bruce. It also includes the township of Huron-Kinloss.

Hydro One completed the first cycle for the region and published the RIP report in August 2017 (Appendix C). The following Needs were identified:

- 115kV L7S Circuit – Capacity Increase
- Power Factor Review at Wingham TS and Bruce HWP B TS
- Poor Customer Delivery Point Performance Review at circuits 61M18, L7S and D10H
- **Step-down Transformation Capacity at Kincardine area**
- End-of-Life Assets at Wingham TS, Stratford TS, Seaforth TS and Hanover TS

The second cycle Needs Assessment report was published in May 2019 by Hydro One. This was followed by a Scoping Assessment report published by IESO in September 2019. The IRRP for this region is currently underway and is expected to be completed by Q2 2021.

Station capacity at Douglas Point TS was approaching limits based on anticipated load growth in the Kincardine area, in the last Regional Planning cycle. Possible solutions to address the increase load demand, such as upsizing existing transformers, permanent load transfers to neighboring load supply stations and building a new DESN facility were considered. Hydro One Distribution was working with its customer to determine their connection capacity requirements, size and timeline. Due to lack of committed load, and the incoming of natural gas in the Kincardine area, a decline in winter load demand is observed at Douglas Point TS, based on new load forecast. Therefore no mitigation is required at the time.

None of the above needs/projects are expected to have any cost allocation to HOD. The needs identified in the NA will be further discussed in the upcoming RIP.

Niagara

The Niagara Region comprises the municipalities of City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-On-The-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County has been included in the Niagara Region for Needs Assessment.

Hydro One developed and published the RIP report in March 2017 (Appendix C), and the next cycle of Regional Planning for this region is currently anticipated to commence in 2021 due to emerging needs in the region.

Based on the previous assessment, the following needs were identified:

- Replacement of EOL Equipment at several stations
- Thermal Overloading on 115kV Q4N **-** Under high generation scenarios at Sir Adam Beck GS #1, the loading on Q4N (Beck #1 SS x Portal Jct) can exceed circuit ratings. The potential overloading issue will be addressed under sustainment project that is scheduled for completion in 2021.

None of the projects above are expected to have any cost allocation to HOD

The second cycle of Needs Assessment for this region is currently in progress with anticipated completion date in May 2021.

North/East of Sudbury

The geographical area of the North/East of Sudbury Region is the area roughly bordered by Moosonee on the North, Hearst on the North-West, Ferris South and Kirkland Lake on the East.

Hydro One developed and published a RIP in April 2017 (Appendix C). Based on the assessment the following needs were identified:

- Voltage regulations at Timmins TS and Kirkland Lake TS – both of which require no immediate action.

The second cycle of Regional Planning for this region is currently anticipated to commence in Q1 2021.

Renfrew

The Renfrew Region includes all of Renfrew County that is made up of 17 municipalities and City of Pembroke. The rough boundaries of this Region are Ottawa River on the North-East, Algonquin Provincial Park on the West, and Route 508 on the South.

Hydro One led Study Team developed and published a NA followed with a RIP report in July 2016 (Appendix C). There was no near-term need identified other than circuit X1P nearing its capacity, which will be monitored on a regular basis over the next three to five years.

The second cycle of Needs Assessment for this region is currently in progress with anticipated completion date in May 2021.

St. Lawrence

The region starts at Gananoque on the eastern end of Lake Ontario and extends to the inter-provincial boundary with Quebec. The City of Cornwall is supplied by Fortis Ontario with transmission lines from Quebec and is not included in this Region.

Hydro One developed and published a NA report followed by RIP report in July 2016 (Appendix C). There were no needs in the region that required regional coordination.

The next cycle of Regional Planning for this region is currently anticipated to commence in Q2 2021.

Hydro One Distribution is an active participating member on the regional Study Teams and Hydro One is looking forward to continue working with Hydro One Distribution in executing the regional planning process. Please feel free to contact me if you have any questions.

Sincerely,

Ajay Garg, Manager – Regional Planning Coordination
Hydro One Networks Inc.

Appendix A. Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee*
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge- Guelph ("KWCG")	Northwest Ontario	Renfrew
Toronto	Windsor-Essex	St. Lawrence

*This region is not within Hydro One's territory.

Appendix B. List of LDCs for Each Region

(Hydro One as Upstream Transmitter)

Region	LDCs
1. Burlington to Nanticoke	• Energy+ Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Alectra Utilities Corporation • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited • Elexicon Energy Inc.
4. GTA West	• Burlington Hydro Inc. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Energy+ Inc. • Centre Wellington Hydro Ltd. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.

6. Toronto	• Alectra Utilities Corporation • Hydro One Networks Inc. • Toronto Hydro Electric System Limited • Elexicon Energy Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity • Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines lnc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior* *Hydro One Sault Ste. Marie L.P. is the Lead Transmitter for the region.	• Algoma Power Inc. • Chapleau PUC • Sault Ste. Marie PUC • Hydro One Networks Inc.
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Elexicon Energy Inc.
11. London Area	• Entegrus Power Lines lnc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Elexicon Energy Inc.

13. South Georgian Bay/Muskoka	• EPCOR • Hydro One Networks Inc. • InnPower Corporation • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Alectra Utilities Corporation • Elexicon Energy Inc. • Elexicon Energy Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines lnc. [Chatham- Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines lnc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* * Changes to the May 17, 2013 OEB Planning Process Working Group Report

19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc.

Appendix C

Most Recent Regional Planning Reports

1. Burlington to Nanticoke: 2nd Cycle RIP Report
2. Greater Ottawa: 2nd Cycle NA Report
3. GTA North: 2nd Cycle RIP Report
4. GTA West: 2nd Cycle NA Report
5. Kitchener-Waterloo-Cambridge-Guelph: 2nd Cycle NA Report
6. Toronto: 2nd Cycle RIP Report
7. Windsor-Essex: 2nd Cycle RIP Report
8. GTA East: 2nd Cycle RIP Report
9. Northwest Ontario: 2nd Cycle NA Report
10. East Lake Superior: 2nd Cycle NA Report
11. London Area: 2nd Cycle NA Report
12. Peterborough to Kingston: 2nd Cycle NA Report
13. South Georgian Bay/Muskoka: 2nd Cycle NA Report
14. Sudbury/Algoma: 2nd Cycle NA Report
15. Chatham/Lambton/Sarnia: 1st Cycle RIP Report
16. Greater Bruce/Huron: 2nd Cycle NA Report

17. Niagara: 1st Cycle RIP Report

18. North/East of Sudbury: 1st Cycle RIP Report

19. Renfrew: 1st Cycle RIP Report

20. St. Lawrence: 1st Cycle RIP Report

SECTION 3.5 – DSP – PERFORMANCE MEASUREMENT AND OUTCOMES

3.5.1 INTRODUCTION

The RRF is an outcomes-based approach to regulation. Hydro One recognizes the need to demonstrate how it will achieve the four RRF outcomes: customer focus, operational effectiveness, financial performance and public policy responsiveness. The Electricity Distributor Scorecard, including the targets in Figure 1, show Hydro One's success in achieving these outcomes and the performance levels that Hydro One expects to achieve over the 2023-2027 rate setting period. The Electricity Distributor Scorecard is the OEB mandated scorecard for all Ontario electricity distributors and is discussed in section 3.5.2 of this Exhibit. For additional details on the performance management framework, please refer to SPF Section 1.5.

In addition to the measures already reported through the Electricity Distributor Scorecard, Hydro One is reporting on several additional performance measures in its Distribution OEB Scorecard that also demonstrate the distribution system outcomes for the Company (discussed in section 3.5.3 of this Exhibit). The Distribution OEB Scorecard is a scorecard developed by Hydro One to supplement the Electricity Distributor Scorecard. It contains additional measures that provide greater transparency to the outcomes that customers value and to areas that Hydro One has targeted for improved performance.

Lastly, section 3.5.4 provides a discussion of the OEB's Activity and Performance-based Benchmarking (APB) report and results.

Hydro One is committed to both sets of performance measures as it evaluates its progress executing its 2023 to 2027 investment plan that aligns the needs and preferences of customers, compliance, condition needs of Company assets, and rate impacts. Hydro One's plan has a number of initiatives that control costs, increase productivity and maintain levels of reliability in rural and urban areas. These are all outcomes that customers have indicated they value, are central to Hydro One's Business Objectives, and the OEB's RRF.

For the Electricity Distributor Scorecard and the Distribution OEB Scorecard, Hydro One provided targets up to and including 2022 in the last distribution application (EB-2017-0049). Actual results up to and including 2017 were provided in the last distribution application for the Distribution OEB Scorecard while results up to and including 2019 were provided for the Electricity Distributor Scorecard by means of the Company's RRR filings with the OEB.

3.5.2 OEB ELECTRICITY DISTRIBUTOR SCORECARD

The Electricity Distributor Scorecard is provided in the Figure 1 below, and includes targets for the 2023 to 2027 period. In addition to reporting the Electricity Distributor Scorecard as part of the annual RRR filing with the OEB, the Executive Leadership Team reviews progress on these metrics on a regular basis as described in the Performance Reporting Governance Document, SPF Section 1.5, Attachment 1.

Performance Outcomes	Performance Categories	Measures		2016	2017	2018	2019	2020	Trend	OEB Targets 2020: Industry	OEB Targets 2020: Distributor	Hydro One Targets: 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time		98.6%	98.06%	99.32%	99.81%	99.78%	▲	90.0%		98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
		Scheduled Appointments Met On Time		99.50%	98.94%	99.95%	100.0%	99.98%	▲	90.0%		99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		Telephone Calls Answered On Time		74.20%	81.85%	78.05%	76.83%	70.18%	▼	65.0%		80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
	Customer Satisfaction	First Contact Resolution		82%	85%	87%	85%	77%	▼			86.0%	87.0%	87.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%
		Billing Accuracy		99.04%	99.28%	99.43%	99.41%	99.35%	▲	98.0%		99.0%	99.0%	99.0%	99.0%	99.0%	98.0%	98.0%	98.0%	98.0%	98.0%
		Customer Satisfaction Index		84%	85%	86%	84%	82.6%	▼			87.0%	87.5%	88.0%	88.5%	89.0%	85.0%	85.0%	86.0%	86.0%	87.0%
Operational Effectiveness	Safety	Level of Public awareness		81%	81%	80%	80%	78%	▼								80%	80%	80%	80%	80%
		Level of Compliance with Ontario Regulation 22/04		NI	C	C	C	C			C	c	C	C	C	C	C	C	C	C	C
		Serious Electrical Incident Index	Number of General Public Incidents	11	8	11	18	33	▲		5				12	4					
			Rate per 10, 100, 1000km of line	0.091	0.065	0.090	0.146	0.267	▲		0.040				0.061						
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		7.83	7.95	6.82	7.04	7.27	▼		7.56	7.0	6.7	6.4	6.1	5.8	4.7	4.4	4.3	4.3	4.2
		Average Number of Times that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		2.47	2.32	2.21	2.50	2.54	▲		2.52	2.4	2.3	2.2	2.1	2.0	2.1	2.0	1.9	1.9	1.8
	Asset Management	Distribution System Plan Implementation Progress		105%	103%	97.93%	106.6%	100.2%	▼			100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Cost Control	Efficiency Assessment		4	4	4	4	Aug.'21	►			5	5	5	5	5					
		Total Cost per Customer		$ 987	$ 974	$ 1,022	$ 1,051	Aug.'21	▲												
		Total Cost per km of Line		$10,551	$10,444	$11,069	$11,472	Aug.'21	▲												
Public Policy Responsiveness	Conservation & Demand Management	Net Cumulative Energy Savings		42.50%	80.83%	98.0%	114.0%	N/A	▲		N/A	75.9%	88.9%	N/A							
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	99.71%	100.0%	100.0%	100.0%	▲			99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		New Micro-embedded Generation Facilities Connected On Time		99.22%	99.77%	99.45%	96.43%	97.10%	▼	90.0%		99.0%	99.0%	99.0%	99.0%	99.0%	98.0%	98.0%	98.0%	98.0%	98.0%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.80	0.55	0.50	0.62	0.72													
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.46	1.39	1.44	1.61	1.71													
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.19%	8.78%	9.00%	9.00%	9.00%													
			Achieved	8.41%	7.94%	8.07%	10.90%	10.56%													

Legend: 5-year trend (or all available years)

▲ up ▼ down ► flat

OEB & Hydro One target met | OEB or Hydro One target met | OEB & Hydro One target not met

Figure 1: Electricity Distributor Scorecard

3.5.2.1 CUSTOMER FOCUS MEASURES

3.5.2.1.1 SERVICE QUALITY

3.5.2.1.1.1 NEW RESIDENTIAL/SMALL BUSINESS SERVICES CONNECTED ON TIME

Performance Category	Measure	Description
Service Quality	New Residential/Small Business Services Connected on Time	This measure assesses Hydro One's ability to process new connection requests for residential and small business low-voltage customers (those with service less than 750 V), within five business days (or as agreed to by the customer and Hydro One).

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
New Residential/Small Business Services Connected on Time	98.6%	98.06%	99.32%	99.81%	99.78%	▲	90.0%		98.0%	98.0%	98.0%

Performance on this measure has trended positively over the 2016 to 2020 period, averaging 99.1% on-time connections for new residential and small business services, consistently exceeding the industry target of 90%.[1]

In 2020, Hydro One processed 14,123 new connection requests for residential and small business low-voltage customers (those with service less than 750 V). Of these, 99.8% were completed within five business days (or as otherwise agreed to by the customer and the distributor), better than the industry target of 90% for the eighth consecutive year and better than the 2020 internal target of 98%, despite significant storm events and impact from COVID-19.

[1] New Residential/Small Business Services connected on Time is shown in Exhibit A-05-03 and A-05-03, Attachment 1, as Low Voltage Connections.

In 2019, Hydro One processed 14,131 new connection requests for residential and small business low-voltage customers (those with service less than 750 V). Of these, 99.8% were completed within five business days (or as otherwise agreed to by the customer and the distributor), better than the industry target of 90% for the seventh consecutive year and better than the 2019 target of 98%.

In 2018, Hydro One processed 17,658 new connection requests for residential and small business low-voltage customers (those with service less than 750 Volts). Of these, 99.3% were completed within five business days (or as otherwise agreed to by the customer and the distributor), better than the industry target of 90% for the sixth consecutive year and better than the 2018 target of 98%.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measure	**Industry**	**Distributor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
New Residential/Small Business Services Connected on Time	90.0%		98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%

As Hydro One continued to improve over past years, Hydro One continues to challenge itself by setting internal performance targets higher than OEB standards and industry targets. The Company's steady improvement over the past five years is attributable mainly to strong customer-focused business processes, improvements in scheduling practices, and focus on achievement of an internal target of 98%.

3.5.2.1.1.2 SCHEDULE APPOINTMENTS MET ON TIME

Performance Category	Measure	Description
Service Quality	Scheduled Appointments Met on Time	This measure applies to appointments where customer presence is required and also to those where customers do not need to be present. When a customer requests an appointment, the appointment must be scheduled within five business days (or as otherwise agreed to by the customer and the distributor). If customer presence is required, the distributor must commit to, and arrive within a four-hour window for the appointment. If customer presence is not required, the distributor must arrive on the scheduled date.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

						OEB Targets 2020		Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Scheduled Appointments Met On Time	99.50%	98.94%	99.95%	100.0%	99.98%	▲	90.0%		99.0%	99.0%	99.0%

Over the past five years, Hydro One has averaged 99.7% for its ability to meet scheduled appointments on-time and performance has trended positively, consistently exceeding the industry target of 90%.[2]

Hydro One scheduled and met 25,811 appointments in 2020 where the customer presence was required. The Business recorded a 100% success rate in meeting these commitments, better than the industry target of 90% for the eighth consecutive year and better than the 2020 internal target of 99%, despite significant storm events and impact from COVID-19.

Hydro One scheduled 31,564 appointments in 2019. The Company recorded a 100% success rate in meeting these commitments, better than the industry target of 90% for the seventh consecutive year and better than the 2019 target of 99%. The result for 2019 represents an

[2] Scheduled Appointments Met On Time is shown in Exhibit A-05-03 and A-05-03, Attachment 1, as Appointments Met.

increase compared to the prior year. The Company's performance in appointment scheduling has benefited from the same factors that contributed to the ability to connect residential and small business services within five business days.

Hydro One scheduled and met 32,262 appointments in 2018 where the customer presence was required. The Company recorded a 99.95% success rate in meeting these commitments, better than the industry target of 90% for the sixth consecutive year and better than the 2018 target of 99%. The result for 2018 represents a 1% increase compared to the prior year.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measure	Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
Scheduled Appointments Met On Time	90.0%		99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%

As Hydro One continued to improve over past years, Hydro One continues to challenge itself by setting internal performance targets higher than OEB standards and industry targets. The Company's steady improvement over the past five years is attributable mainly to strong customer-focused business processes, improvements in scheduling practices, and focus on achievement of an internal target of 99%.

3.5.2.1.1.3 TELEPHONE CALLS ANSWERED ON TIME

Performance Category	Measure	Description
Service Quality	Telephone Calls Answered on Time	The OEB's Distribution System Codes (DSC) requires call centre staff to answer calls within 30 seconds, 65% of the time, whenever the customer reaches an agent—either directly or by means of a transfer. In the two years since the insourcing of the call centre, Hydro One has exceeded this target.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**Industry**	**Distributor**	**2018**	**2019**	**2020**
Telephone Calls Answered On Time	74.20%	81.85%	78.05%	76.83%	70.18%	▼	65.0%		80.0%	80.0%	80.0%

Average performance over the past five years was 76.2% and the performance trend is indicating a reduction in answering telephone calls on time since 2017, although still significantly above the industry target of 65%.[3]

In 2020, the rate dropped to 70.2% of calls being answered within 30 seconds. This rate still exceeded the industry target by 5.2%, but fell short of the company's own target of 80%. Hydro One identified a number of reasons for this decline.

- In March 2020, Hydro One mobilized its entire contact center operations to a work from home model in response of COVID-19 measures. During this initial period the contact center experienced increased call interaction times once staff adapted to their work from home settings, this resulted in increased customer wait times.
- In October 2020, Hydro One underwent a replacement of their telephony platform as well as its end user interfaces. Migration of the newly integrated platform was a staged approach spanning over four weeks in duration. Interaction handle times ran much higher than initially anticipated over the first three months, due to increased user adoption rates of the front-end systems.
- During the migration to the new telephony system, the volume of calls handled by the call centre increased due to a new government initiative that gives customers the option to choose between time-of-use and tiered rates, and due to a winter storm that affected approximately 240,000 Hydro One customers across the province. This unexpected volume increase resulted in longer customer wait times.

[3] Telephone Calls Answered On Time is shown in Exhibit A-05-03 and A-05-03, Attachment 1, as Telephone Accessibility.

In 2018 and 2019, the Business answered 78.05% and 76.83% of calls within 30 seconds, respectively, exceeding the industry target by about 13% in 2018 and 12% in 2019. However, Hydro One narrowly missed its own target of 80% that was set in 2017.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
Telephone Calls Answered On Time	65.0%		80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%

Hydro One has set an answered call target of 80% within 30 seconds for the period 2023 to 2027, which remains consistent with the targets set for 2021 to 2022. While this is an ambitious target that exceeds the average of the past five years by about four percentage points, Hydro One is committed to providing a consistent and high-level customer service. With the new Telephony platform firmly in place, this goal should be achievable over the test years.

3.5.2.1.2 CUSTOMER SATISFACTION

3.5.2.1.2.1 FIRST CONTACT RESOLUTION

Performance Category	Measure	Description
Customer Satisfaction	First Contact Resolution	First Contact Resolution (FCR) reports the success of the distributor in resolving a customer's issue during the first contact, as reported by the customer. Hydro One's Distribution Business measures FCR based on transactional surveys that are performed within five days of our interaction with the customer.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
First Contact Resolution	82%	85%	87%	85%	77%	▼			86.0%	87.0%	87.0%

Performance for first contact resolution (FCR) over the prior five years has trended downwards, due to the 2020 result of 77%, averaging 83% over this same period.

As part of the last distribution application, Hydro One set ambitious targets for FCR to reflect its commitment of making it easier to do business with for its customers. Hydro One has since made improvements, and exceeded its 2018 target of 86% by one percentage point. However, the Company missed the 87% target by two percentage points in 2019.

In 2020, 77% of issues were resolved during the first contact with a customer, missing the 2020 target of 87%. Hydro One has identified a number of reasons for this:

- The 2020 results are less accurate than in previous years, due to a COVID-related suspension of the survey between March and August, resulting in incomplete data for the full year.
- In the earlier part of the year, Hydro One suspended most of its non-essential work due to COVID, resulting in the delayed completion of field based work.
- Over the past few years, Hydro One has invested in its communication channels to offer customers more choice and convenient options to complete transactions. This has led to a shift in the types of calls to the call centre. Simple transactions are now routinely completed via the web, or through the Interactive Voice Response (IVR) without the need to engage a Customer Service Representative (CSR). The result is a higher share of complex transactions that are handled by CSRs.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
First Contact Resolution			88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%

Going forward, Hydro One aims to achieve a consistent FCR target of 88% throughout the entire test years from 2023 to 2027, which remains consistent with the target set for 2021 to 2022.

3.5.2.1.2.2 BILLING ACCURACY

Performance Category	Measure	Description
Customer Satisfaction	Billing Accuracy	Billing Accuracy is the measure for the number of bill issued that are derived based on actual meter readings and do not require any subsequent adjustments as a percentage of the total number of billed issued in a given bill period.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Billing Accuracy	99.04%	99.28%	99.43%	99.41%	99.35%	▲	98.0%		99.0%	99.0%	99.0%

Billing accuracy has improved over the past five years, averaging 99.3% and better than the industry target of 98% every year.

Between 2018 and 2020, the Business issued over 13 million bills annually and achieved a 99.4% Time of Use billing accuracy in 2020, exceeding the industry target by 1.4% and the Hydro One target by 0.4% each year. The strong billing accuracy results are attributable to ongoing business process optimization and a continued focus on addressing smart meters that do not meet the necessary quality levels.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
Billing Accuracy	98.0%		99.0%	99.0%	98.0%	98.0%	98.0%	98.0%	98.0%

Over the next few years, Hydro One expects billing accuracy to temporarily decline slightly to 98%. This is driven by the degradation of the current smart metering system (AMI 1.0), which was installed between 2007 and 2013 and is reaching the end of its expected service life. Many of the approximately 1.4 million meters currently in service will soon surpass the 15-year service life, and Hydro One has already started seeing meters failing at an increasing rate. Hydro One's plan is to begin mass replacing AMI 1.0 meters with new AMI 2.0 meters beginning in 2024 through 2028. It is expected that billing accuracy will decline initially as AMI 1.0 meters continue to fail but then increase proportional to their replacement with AMI 2.0 meters and the implementation of the new network.

3.5.2.1.2.3 CUSTOMER SATISFACTION INDEX

Performance Category	Measure	Description
Customer Satisfaction	Customer Satisfaction Index	Hydro One measures Customer Satisfaction using an equally weighted composite index consisting of the following seven components: (1) Outage Handling; (2) Call Centre Customer Satisfaction; (3) Forestry Services; (4) Lines New Connections and Upgrades; (5) My Account; (6) Large Distribution Accounts (LDAs); and (7) Distributed Generation Customers (estimated as per cent of new connections met on-time).

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Customer Satisfaction Index	84%	85%	86%	84%	82.6%	▼			87.0%	87.5%	88.0%

Over the past five years, customer satisfaction has trended downwards, primarily due to the results in 2019 and 2020, and has averaged 84%. In 2017, the Company set targets for the years 2018 to 2020 that exceeded past performance and aimed for a consistent increase. In 2018, the 87% target was narrowly missed by one percentage point. Satisfaction has declined to 84% in 2019 and 83% in 2020, missing the targets for these years by 3.5 and five percentage points respectively.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
Customer Satisfaction Index			88.5%	89.0%	85.0%	85.0%	86.0%	86.0%	87.0%

The results for this index come from different transactional and perception surveys, some of which underwent a methodological change in 2020, leading to the need for an adjustment of targets going forward. Based on the new methodology, Hydro One is aiming to gradually improve overall customer satisfaction from 85 to 87 per cent between 2023 and 2027.

To achieve these improvements, Hydro One remains committed to delivering high quality service to its customers and is planning a variety of initiatives:

- Hydro One has started a new company-wide Outage Planning Excellence (Distribution OPE) initiative aimed at improving the outage experience for customers across all segments.
- Since the insourcing of the call centre in March 2018, Hydro One has provided regular coaching and training to all Customer Service Representatives (CSRs). Hydro One is planning to continue these efforts and engage in additional quality assurance initiatives.
- Hydro One is adopting a customer experience approach to identify and reduce pain points for customers and create better customer journeys.
- The myAccount satisfaction score provides an opportunity for improvement. Going forward, Hydro One is making significant enhancements to the myAccount portal, which are expected to be reflected in the myAccount customer satisfaction score. Hydro One predicts a sharp increase in customer satisfaction in 2021 and further gradual increases by 2027.

3.5.2.2 OPERATIONAL EFFECTIVENESS MEASURES

3.5.2.2.1 SAFETY

In April 2015, the Electrical Safety Authority (ESA) made recommendations to the OEB for a scorecard public safety measure that includes three main components: A) Public Awareness of Electrical Safety, B) Compliance with Ontario Regulation 22/04 made under the Electricity Act, 1998, and C) the Serious Electrical Incident Index. Components B and C were reported in previous years and results for Component A were tracked for the first time for fiscal 2015 performance.

3.5.2.2.1.1 LEVEL OF PUBLIC AWARENESS

Performance Category	Measure	Description
Safety	Level of Public Awareness	Hydro One measures public awareness of electrical safety every two years. To gauge overall electrical safety awareness amongst the general public, six core questions are asked to randomly-selected Ontario residents. These questions include: likelihood to call before you dig, impact of touching a power line, proximity to overhead power line, danger of tampering with electrical equipment, proximity to downed power lines, and actions taken in vehicle in contact with wires.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Level of Public awareness	81%	81%	80%	80%	78%	▼					

The level of public awareness has trended slightly downward over the prior five years, averaging 80%.

Hydro One’s overall public safety awareness index score was 78% in 2020. These strong results are a reflection of Hydro One’s communications with customers and communities regarding the impact of touching a power line, proximity to overhead power lines, danger of tampering with electrical equipment, etc. Although the overall score remained statistically unchanged from 2018 (80%) to 2020 (78%) based on the sample size, education on proximity to overhead power lines and downed power lines needs to be reinforced to the general public via ongoing outreach to customers and communities.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
Level of Public awareness					80%	80%	80%	80%	80%

Scores of 80% are expected to remain into the future.

3.5.2.2.1.2 LEVEL OF COMPLIANCE WITH ONTARIO REGULATION 22/04

Performance Category	Measure	Description
Safety	Level of Compliance with Ontario Regulation 22/04	Ontario Regulation 22/04 was introduced in early 2004 following recommendations from the ESA to enhance electrical safety for the people of Ontario. The regulation sets the basis for the requirements for the safe operation of the distribution system in Ontario. This measure is based on ESA's assessment of Hydro One's performance based on 3 major factors: 1. Hydro One's performance on the Annual External Audit and Self Declaration of Compliance to Regulation 22/04, 2. Hydro One's performance on its Due Diligence Inspections and; 3. Hydro One's performance on Public Safety Concerns.

Distribution companies are required to be audited yearly on the design, construction, and maintenance of distribution systems in accordance with the regulation. An external auditor performs the audit. A final report by the external auditor, along with a signed declaration of compliance to the regulation by an officer of the company for all sections that are not covered by the audit, is provided to the ESA. The performance target for compliance with the regulation is for the distributor to be fully compliant, and is recorded as Compliant (C), Non-Compliant (NC), or Needs Improvement (NI). Based on these three factors, ESA assesses compliance and provides Hydro One with a rating.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**Industry**	**Distributor**	**2018**	**2019**	**2020**
Level of Compliance with Ontario Regulation 22/04	NI	C	C	C	C			C	C	C	C

Hydro One has received a "Compliant" rating from ESA for 2018-2020.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	C	C	C

Hydro One expects to receive a "Compliant" rating every year.

3.5.2.2.1.3 SERIOUS ELECTRICAL INCIDENT INDEX

Performance Category	**Measure**	**Description**
Safety	Serious Electrical Incident Index	The Serious Electrical Incident Index was designed to track and help improve public electrical safety on the distribution network over time. A distributor, its contractors and operators are required to report to the ESA, within 48 hours, any serious electrical incident involving members of the general public. A serious electrical incident is defined as any electrical contact or any fire or explosion that caused or has the potential to cause, critical injury or death in any part of the distribution system operating at greater than 750 Volts (except as caused by lightning strikes).

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

								OEB Targets 2020		Hydro One Targets		
Measures		2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Serious Electrical Incident Index	Number of General Public Incidents	11	8	11	18	33	▲		5			
	Rate per 10, 100, 1000km of line	0.091	0.065	0.090	0.146	0.268	▲		0.040			

The average number of general public incidents and the rate per km of line have both increased over the past five years, averaging 16 incidents and 0.132 incidents per km of line over this period.

For 2020, the ESA identified 33 incidents that met the serious electrical incident criteria (actual or potential electrical contact). Of the 33 incidents, 21 of those are motor vehicle accidents which is an increase of five from 2019. Over the last five years, motor vehicle collisions represent the largest contributor to the company's serious electrical incidents on the distribution system (64% in 2020, 89% in 2019, 55% in 2018, 63% in 2017, 73% in 2016, and 80% in 2015). Incidents involving customers who felled a tree into Hydro One's lines increased to five from one in 2019. Failed equipment and a large vessel move represent the seven remaining incidents in 2020.

For 2019 and 2018, the ESA identified 18 incidents and 11 incidents respectively that met the serious electrical incident criteria (actual or potential electrical contact).

TARGETS FOR THE 2021-2027 PERIOD

		OEB Targets 2020		Hydro One Targets						
Measures		Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
Serious Electrical Incident Index	Number of General Public Incidents		5	12	4					
	Rate per 10, 100, 1000km of line		0.040	0.061						

Hydro One's forecast follows the formula that ESA utilizes for this metric. This formula is based on the previous five-year average, with a reduction of 30%. The Electrical Safety Authority provides the target based on the most recent year, and this target cannot be projected into the later years of the plan at the date of filing. For 2021, Hydro One has a target of 12 incidents from the ESA. As noted in Introduction section this exhibit, targets for 2022 were set in the last distribution application are maintained as filed previously.

3.5.2.2.2 SYSTEM RELIABILITY

3.5.2.2.2.1 AVERAGE NUMBER OF HOURS THAT POWER TO A CUSTOMER IS INTERRUPTED

Performance Category	Measure	Description
System Reliability	Average Number of Hours that Power to a Customer Is Interrupted	*Average number of hours that power to a customer is interrupted* normally is measured in SAIDI (System Average Interruption Duration Index): It is defined as the system average interruption duration (in hours) for customer served per year. $\text{SAIDI} = \frac{\text{Total Customer Hours of Interruption}}{\text{Total Customers Served}}$ In Hydro One's reporting for OEB Electricity Distribution Scorecard, all planned and unplanned interruptions of one minute or more (excluding Loss of Supply and excluding Force Majeure Events) are used to calculate this measure.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**Industry**	**Distributor**	**2018**	**2019**	**2020**
Average Number of Hours that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)	7.83	7.95	6.82	7.04	7.27	▼		7.56	7.0	6.7	6.4

SAIDI has improved over the past five years, averaging 7.38 hours of interruption. In 2020, Hydro One's Distribution average interruption duration was 7.27 hours or 0.87 hours longer than the target of 6.4 hours and longer than the previous year. This was mainly due to 2020 being an above average storm year in which Hydro One's service territory experienced 41 storm days, excluding Force Majeure (FM) days, while Hydro One recorded on average 32 storm days annually from 2015 to 2019.

For 2019, SAIDI performance was 0.34 hours worse than the target of 6.7 hours mainly due to increased SAIDI contribution from equipment failures.

In 2018, Hydro One's Distribution average interruption duration was 6.8 hours, and better than the target of 7.0 hours.

Figure 2 below provides a breakdown of SAIDI contribution.

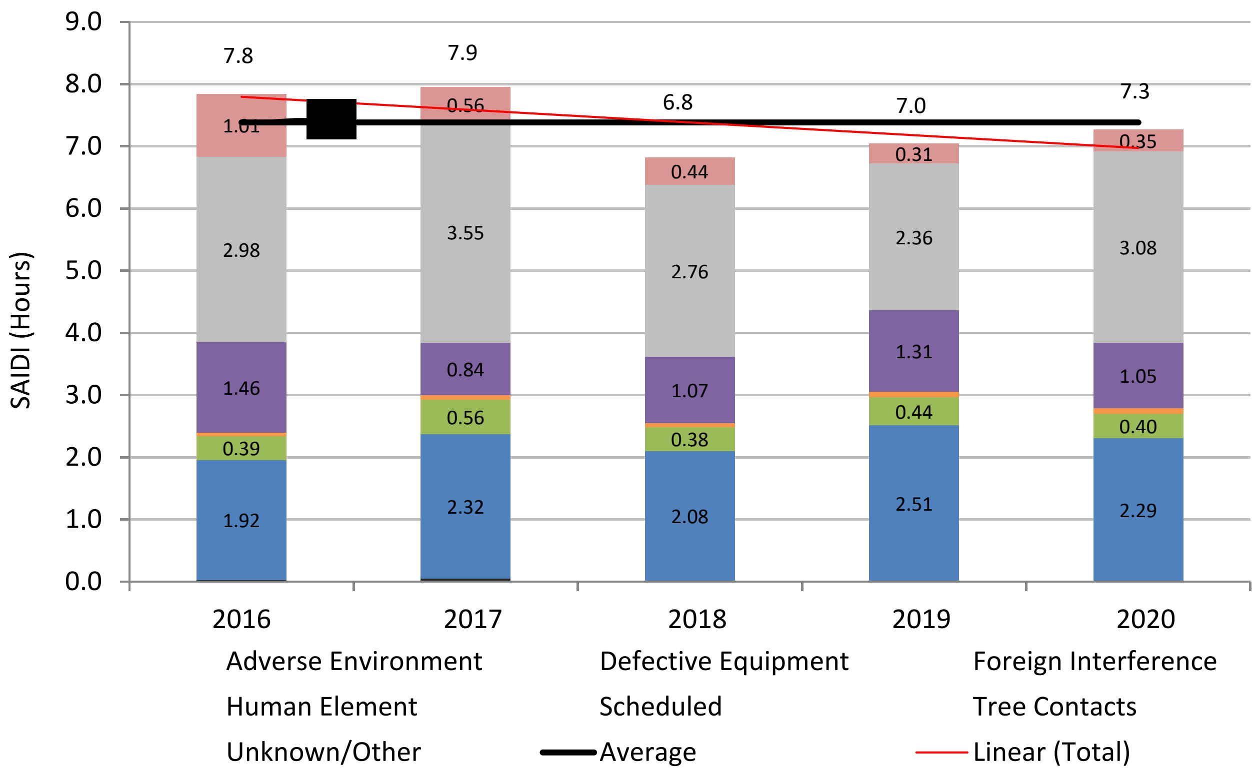


Figure 2: SAIDI Contribution

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Average Number of Hours that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		7.56	6.1	5.8	4.7	4.4	4.3	4.3	4.2

The 2023 to 2027 targets were established based on the estimate year over year improvement due to the benefit from programs and investments such as Vegetation Management (Exhibit E-03-02, section 2.4), Worst Performing Feeders (DSP Section 3.11, D-SS-05), Reliability Improvements (DSP Section 3.11, D-SS-04), Energy Storage Solutions (DSP Section 3.11, D-SS-04), and improved storm response and outage planning (Exhibit E-04-05, section 2.2.3).

3.5.2.2.2.2 AVERAGE NUMBER OF TIMES THAT POWER TO A CUSTOMER IS INTERRUPTED

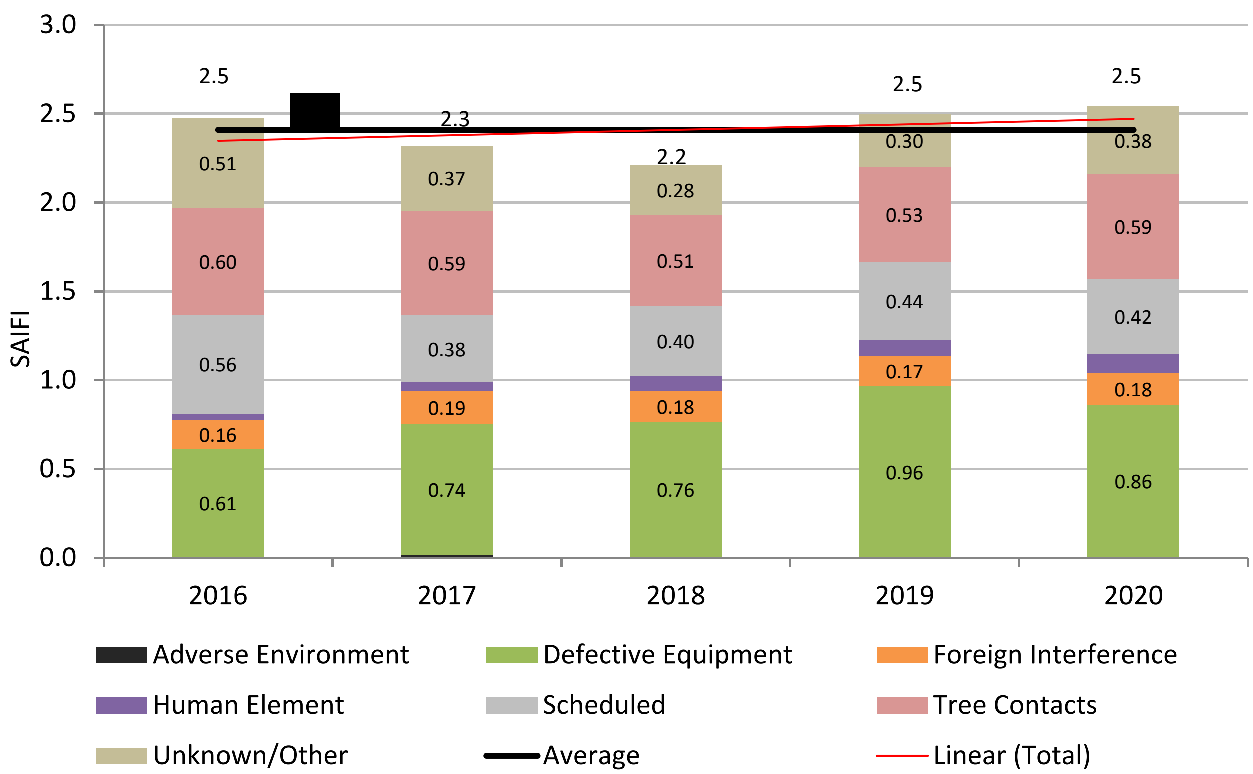
Performance Category	Measure	Description
System Reliability	Average Number of Times that Power to a Customer Is Interrupted	*Average number of times that power to a customer is interrupted* normally is measured in SAIFI (System Average Interruption Frequency Index): It is defined as the system average interruption frequency for customer served per year. $\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$ In Hydro One's reporting for OEB Electricity Distribution Scorecard, all planned and unplanned interruptions of one minute or more (excluding Loss of Supply and excluding Force Majeure Events) are used to calculate this measure.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**Industry**	**Distributor**	**2018**	**2019**	**2020**
Average Number of Times that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)	2.47	2.32	2.21	2.50	2.54	▲		2.52	2.4	2.3	2.2

SAIFI over the past five years has increased, averaging 2.4 interruptions. In 2020, Hydro One's Distribution average interruption frequency was 2.5 or 0.3 higher than the target of 2.2. This was mainly due to 2020 being an above average storm year in which Hydro One's service territory experienced 41 storm days, excluding FM days, while Hydro One recorded on average 32 storm days annually from 2015 to 2019.

1 Performance in 2019 was 0.3 higher than the target, while 2018 was better than target by 0.19. The impact on SAIFI performance in 2019 was due to an increase in tree contact and equipment failures. Figure 3 below provides a breakdown of SAIFI contribution.



4 **Figure 3: SAIFI Contribution**

6 **TARGETS FOR THE 2021-2027 PERIOD**

	OEB Targets 2020		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Average Number of Times that Power to a Customer is Interrupted (Excluding LOS and Excluding FM)		2.52	2.1	2.0	2.1	2.0	1.9	1.9	1.8

7 The 2023 to 2027 targets were established based on the estimate year over year improvement due to the benefit from programs and investments such as Vegetation Management (Exhibit E-

03-02, section 2.4), Worst Performing Feeder (DSP Section 3.11, D-SS-05), Energy Storage Solutions (DSP Section 3.11, D-SS-04), and improved outage planning (Exhibit E-04-05, section 2.2.3).

3.5.2.2.3 ASSET MANAGEMENT

3.5.2.2.3.1 DISTRIBUTION SYSTEM PLAN IMPLEMENTATION PROGRESS

Performance Category	Measure	Description
Asset Management	Distribution System Plan Implementation Progress	Established by the OEB in 2013, the DSP implementation progress is a distributor-defined performance metric. Hydro One Distribution Business's DSP outlines the Business's forecasted capital expenditures over the next five years, required to maintain and expand electricity system to serve current and future customers. Progress is measured as the ratio of actual total in-service capital expenditures made in a calendar year to the total amount of planned in-service capital expenditures for the same year.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2019		Hydro One Targets		
Measures	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Distribution System Plan Implementation Progress	105%	103%	97.93%	106.6%	100.2%	▼			100%	100%	100%

Performance over the 2018 to 2020 period has averaged 102% and is trending downwards towards the 100% target.

At year-end 2019, distribution in-service additions were $593.2M compared to a scorecard target of $556.5M which was approximately 7% above target, in part as a result of the OEB's December 19, 2019 ruling on the pension motion arising from EB-2017-0049, which reaffirmed the OEB's prior decision; this resulted in a transfer to property, plant, and equipment and intangible assets of approximately $37M, the portion of attributable to capital expenditures.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Distribution System Plan Implementation Progress			100%	100%	100%	100%	100%	100%	100%

Targets for the 2023 to 2027 period were set at 100% to reflect the desired ratio of total in-service capital expenditures made in the calendar year to the total amount of planned in-service capital expenditures for the same year.

3.5.2.2.4 COST CONTROL

Hydro One's performance for the Cost Control measures is assessed by the Pacific Economics Group Inc. (PEG) on an annual basis, and as part of the RRR process for all distributors. PEG uses a propriety methodology to calculate the results and as such, Hydro One does not set targets for the unit cost PEG Cost Control measures. Similar unit cost control measures, for which Hydro One does set targets, are presented in the Distribution OEB Scorecard in section 3.5.3 of this document. The Efficiency Assessment targets are based on the PEG model provided in Exhibit A-5-2, Attachment 1.

3.5.2.2.4.1 EFFICIENCY ASSESSMENT

Performance Category	Measure	Description
Cost Control	Efficiency Assessment	Cost control metrics are evaluated on behalf of the OEB by an independent party, the Pacific Economics Group LLC (PEG). The PEG study segments electrical distributors into five groups based on actual costs vs. the prediction of costs from PEG's econometric model. Group 1 distributors are considered most efficient, with actual costs 25% or more below predicted costs. Group 5 distributors are considered least efficient, according to the PEG methodology, with actual costs 25% or more above predicted costs.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Efficiency Assessment	4	4	4	4	Aug.'21	▸			5	5	5

For the 2016 to 2019 period, Hydro One was assessed by PEG as being in Group 4. Group 4 comprises those utilities with actual costs between 10% and 25% above predicted costs.

TARGETS FOR THE 2021-2027 PERIOD

Targets for the 2023-2027 period are based on the PEG model as outlined in Exhibit A-05-02, Attachment 1.

	OEB Targets 2020		Hydro One Targets						
Measures	Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
Efficiency Assessment			5	5	4	4	4	4	4

3.5.2.2.4.2 TOTAL COST PER CUSTOMER

Performance Category	Measure	Description
Cost Control	Total Cost per Customer	The total cost per customer is defined as the total Capital and Operations Maintenance & Administration (OM&A) costs, divided by the total number of customers served. This includes certain adjustments prescribed by the PEG methodology.

HISTORICAL PERFORMANCE

							OEB Targets 2020		Hydro One Targets		
Measures	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Total Cost per Customer	$987	$974	$1,022	$1,051	Aug.'21	▲					

Hydro One's total cost per customer, as measured by PEG, has averaged $1,009 and is trending slightly higher of this same period.

In 2019, the Company's annual Total Cost per Customer increased by 2.8% (or +$29 per customer) from 2018. The OM&A portion of cost per customer was up slightly due mainly to higher volume of work on vegetation management coverage and increased emergency calls, partially offset by lower corporate support costs and lower costs due to repatriation of the call centre which resulted in operational improvements. The capital portion of the measure increased slightly, due to timing of investments in distribution system connections (Leamington and Enfield transmission stations) and increased investment in distribution modernization initiatives, higher volume of new connections and higher volume of lines and station refurbishments and replacements, partially offset by lower volume of storm-related asset replacements. The increases in costs were offset, in part, by a 0.8% increase in the number of customers.

3.5.2.2.4.3 TOTAL COST PER KM OF LINE

Performance Category	Measure	Description
Cost Control	Total Cost per KM of Line	The total cost per kilometre of line is defined as the total Capital and OM&A costs, divided by the total number of kilometres of line operated to serve customers, along with certain PEG prescribed adjustments.

HISTORICAL PERFORMANCE

							OEB Targets 2020		Hydro One Targets		
Measures	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Total Cost per km of Line	$10,551	$10,444	$11,069	$11,472	Aug.'21	▲					

The average total cost per kilometer of line has increased over the past four years, averaging $10,884, as measured by PEG.

In 2019, the Business's Total Cost per kilometer of line increased 3.6% (or +$403 per kilometre) from 2018. The changes in cost are the same as with the Cost per Customer (see above) but the number of kilometres of line was virtually unchanged year over year.

3.5.2.3 PUBLIC POLICY RESPONSIVENESS MEASURES

3.5.2.3.1 CONSERVATION AND DEMAND MANAGEMENT

3.5.2.3.1.1 NET CUMULATIVE ENERGY SAVINGS

Performance Category	Measure	Description
Conservation and Demand Management	Net Cumulative Energy Savings	Net cumulative energy savings means the total amount of reduction in energy use attributable to a particular energy efficiency program for a stated timeframe. Example CDM program between 2015 and 2020. These changes may implicitly or explicitly include the effects of free ridership, spillover and induced market effects.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**Industry**	**Distributor**	**2018**	**2019**	**2020**
Net Cumulative Energy Savings	42.50%	80.83%	98.0%	114.0%	N/A	▲		1,220.7GWh	75.9%	88.9%	N/A

Over the past several years, Hydro One has been offering Conservation and Demand Management (CDM) programs to residential, small business, low-income, First Nations, commercial, and industrial customers to save energy, save money on electricity bills and make a lasting contribution to reducing long-term energy costs. Most recently, the Company was operating under the Conservation First Framework (CFF) which began in 2015 and commencing in March 2019, will be winding down until mid-2021. Net cumulative energy savings over the past four years have increased, averaging 83%. From 2018-2019 Hydro One achieved 98% and 114% net cumulative energy savings, which exceeded the OEB targets of 75.9% and 88.9% respectively. In a letter[4] dated March 22, 2021, the OEB indicated that in order to reflect the winding down of the CCF, the CMD measure and respective target is being removed from the scorecard. Based on this direction, Hydro One has also removed its previously filed target for 2020 and is not forecasting targets for the 2023-2027 planning period.

[4] OEB, Annual Reporting and Record-keeping Requirements (RRR) and Amendments to the Electricity Distributor Scorecard (2021)

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
Net Cumulative Energy Savings		N/A							

As noted in the preceding section, targets are not being forecast for this measure.

3.5.2.3.2 CONNECTION OF RENEWABLE RESOURCES

3.5.2.3.2.1 RENEWABLE GENERATION CONNECTION IMPACT ASSESSMENTS COMPLETED ON TIME

Performance Category	Measure	Description
Connection of Renewable Resources	Renewable Generation Connection Impact Assessments Completed on Time	A Connection Impact Assessment (CIA) is used to assess the impact of a new connection on the distribution system and is applicable to renewable energy generation facilities that have a name-plate rated capacity of greater than 10 kW. The CIA completed on time is being measured by completing the assessment within 60 days of the receipt of the application as per section 6.2.12 of the DSC.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	2016	2017	2018	2019	2020	Trend	Industry	Distributor	2018	2019	2020
Renewable Generation Connection Impact Assessments Completed On Time	100%	99.71%	100.0%	100.0%	100.0%	▲			99.0%	99.0%	99.0%

Over the past five years, Hydro One has averaged a 99.9% on-time completion rate for renewable generation Connection Impact Assessments (CIA), with a slight upward trend due to a lower completion rate in 2017.

In 2020, Hydro One completed 100% of the CIAs received on-time with a five-year historical average performance of 99.9%. Hydro One's performance over the 2016 to 2020 period was mainly attributable to due diligence oversight.

Both in 2018 and 2019, Hydro One completed new connection impact assessments within the regulatory prescribed timelines allowing Hydro One to achieve a compliance rate of 100%, exceeding Hydro One's own target by 1%.

TARGETS FOR THE 2021-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Renewable Generation Connection Impact Assessments Completed On Time			99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%

Over the term of the Application, Hydro One plans to maintain the internal target at 99%. Hydro One has observed some changes to the nature of generation connection applications to Hydro One since the conclusion of the IESO Feed-in-Tariff (FIT) program in 2017, and expects this trend to continue. Customers are opting for programs that will optimize their load consumption (eg. Energy Storage, Emergency Backup, Load Displacement and Net Metering). Hydro One expects some minor changes to the regulatory requirements for the connection of generation, including renewable resources, but Hydro One expects to meet its internal target through continued due-diligence oversight and workflow automation, including regular monitoring of CIA application volumes and performance against the internal target.

3.5.2.3.2.2 NEW MICRO-EMBEDDED GENERATION FACILITIES CONNECTED ON TIME

Performance Category	Measure	Description
Connection of Renewable Resources	New Micro-Embedded Generation Facilities Connected on Time	This metric measures Hydro One's success in connecting micro-embedded generation facilities (name-plate rated capacity of 10kW or less) 90% of the time within a five business-day window, or at such later date as agreed to by a micro-embedded generator and the distributor, of the generator informing the distributor that it has satisfied all applicable service conditions and received all necessary approvals, as per sections 6.2.7 and 6.2.7A of the DSC.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							OEB Targets 2020		Hydro One Targets		
Measures	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**Industry**	**Distributor**	**2018**	**2019**	**2020**
New Micro-embedded Generation Facilities Connected On Time	99.22%	99.77%	99.45%	96.43%	97.10%	▼	90.0%		99.0%	99.0%	99.0%

On-time connection of micro-embedded facilities has trended slightly downward, averaging 98.4% over the past five years.

In 2020, Hydro One achieved a 97% on-time rate for connecting new micro-embedded generation facilities with a five-year historical average performance of 98.5%. Hydro One's performance over the 2016 to 2020 period was mainly attributable to process improvements and due-diligence oversight.

While Hydro One exceeded the target marginally in 2018 for connecting new micro-embedded generation facilities, the 99% target was narrowly missed by 3% in 2019; this prompted additional oversight and process improvement which was implemented and resulted in improved performance in 2020.

TARGETS FOR THE 2023-2027 PERIOD

	OEB Targets 2020		Hydro One Targets						
Measures	Industry	Distributor	2021	2022	2023	2024	2025	2026	2027
New Micro-embedded Generation Facilities Connected On Time	90.0%		99.0%	99.0%	98.0%	98.0%	98.0%	98.0%	98.0%

Over the term of the Application, Hydro One plans to set the internal target at 98%. Hydro One expects that an internal target of 98% will position itself to remain flexible with connecting new types of customers where, since the cancellation of the IESO's Energy Procurement Programs such as microFIT, customers are opting for Net Metering and other behind the meter generation since the cancellation of the microFIT program. Hydro One expects to meet its internal target through process optimization, workflow automation, improved work notifications/instructions and improved communication of expectations to the field staff.

3.5.2.4 FINANCIAL PERFORMANCE

Hydro One does not forecast targets for the financial performance measures. The basis for the 2019 results is the data submitted as part of the 2019 RRR; the basis for the 2020 results is the Company's 2020 Audited Financial Statements.

3.5.2.4.1 FINANCIAL RATIOS

3.5.2.4.1.1 LIQUIDITY: CURRENT RATIO (CURRENT ASSETS/CURRENT LIABILITIES)

Performance Category	Measure	Description
Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Liquidity is measures as the ratio of the current assets to current liabilities. Current assets is defined as cash or other assets to be converted to cash within the year. Current liabilities is defined as short term debts or financial obligations that become due within the year.

HISTORICAL PERFORMANCE

Measures	2016	2017	2018	2019	2020
Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.80	0.55	0.50	0.62	0.72

The current ratio for 2020 was reported as 0.72, which was higher than all prior years except for 2016, indicating an increase in the net available cash or cash-equivalents on-hand to cover obligations. The increase in 2020 liquidity relative to prior year is attributable primarily to a reduction in the inter-company demand facility due within one year. In 2019, the increased liquidity relative to prior years was due to higher current assets, which include accounts receivables, amounts due from related parties, and other current assets. The higher current ratio in 2016 was primarily due to overall higher current assets and lower current liabilities.

Please refer to Exhibit A-06-02 for more information on Hydro One Distribution's financial information.

3.5.2.4.1.2 LEVERAGE: TOTAL DEBT (INCLUDES LONG-TERM AND SHORT-TERM DEBT) TO EQUITY RATIO

Performance Category	Measure	Description
Financial Ratios	Leverage: Total Debt (Includes Long-Term and Short-Term Debt) to Equity Ratio	The debt-to-equity ratio is a measure of the Business's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors. The OEB-deemed capital structure is 60% debt to 40% equity structure (a ratio of 1.5)

HISTORICAL PERFORMANCE

Measures	2016	2017	2018	2019	2020
Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.46	1.39	1.44	1.61	1.71

For 2020, the debt-to-equity ratio was recorded as 1.71, higher than all prior years. This increase in leverage is attributable to higher long term debt. There was a higher issuance of long-term debt under the Medium-Term Note Program in 2020 compared to prior years.

Please refer to Exhibit A-06-02 for more information on Hydro One Distribution's financial information.

3.5.2.4.1.3 PROFITABILITY: REGULATORY RETURN ON EQUITY

Performance Category	Measure	Description
Financial Ratios	Profitability: Regulatory Return on Equity	Regulatory return on equity is calculated using several regulatory adjustments established in section 2.1.5.6 of the annul RRR filing.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 DEEMED RETURN ON EQUITY

Measures		2016	2017	2018	2019	2020
Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.19%	8.78%	9.00%	9.00%	9.00%
	Achieved	8.41%	7.94%	8.07%	10.90%	10.56%

The 2020 achieved regulatory return on equity (ROE) was 10.56% or 1.56 percentage points higher than the deemed ROE of 9.00%, but within the OEB threshold of +3.00 percentage points. ROE was higher than deemed in 2020 primarily due to higher actual loads than anticipated which resulted in increased revenues, and lower removal costs. After application of the OEB-approved Earnings Sharing Mechanism (ESM), the Company is sharing $14.92M with ratepayers which effectively reduced the 2020 achieved ROE from 10.56% to 10.23%.

The 2019 achieved ROE was 1.90 percentage points higher than the deemed ROE of 9.00%. This difference is primarily due to more favourable weather experienced during the year than anticipated and lower removal costs, partially offset by increased OM&A expenses. After application of the OEB-approved ESM, the Company is sharing $20.18M with ratepayers which effectively reduced the 2019 achieved ROE from 10.90% to 10.45%.

The 2018 achieved ROE was 0.93 percentage points lower than the deemed ROE of 9.00%. This shortfall was due to net income being lower than forecasted, driven mainly by higher than expected OM&A and income tax, offset by higher than forecast revenue.

3.5.3 HYDRO ONE DISTRIBUTION OEB SCORECARD

In the last distribution rate application (EB-2017-0049), Hydro One filed its Distribution OEB scorecard along with targets up to 2022 and actuals for 2017. Figure 4 below.

In this application, Hydro One is proposing to replace the two system reliability (Number of Line Equipment Caused Interruptions and Number of Vegetation Caused Interruptions), as filed in the prior application, with measures that better assess the contribution of these to reliability and to remove the substation caused outages metric. Additionally, Hydro One is proposing to remove the Number of Substation Caused Interruptions metric – this is discussed in additional detail below.

									Hydro One Targets									
RRFE Outcomes		Measure	2016	2017	2018	2019	2020	Trend	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction (%)	66%	71%	76%	86%	87%	▲	74%	75%	75%	76%	76%	87%	87%	87%	87%	87%
		Handling of Unplanned Outages Satisfaction %[5]	75%	76%	80%	78%	77%	▲	77%	78%	78%	79%	79%	80%	81%	82%	82%	83%
		Call Centre Customer Satisfaction %	86%	90%	93%	90%	86%	►	87%	88%	88%	89%	89%	86%	86%	86%	86%	86%
		My Account Customer Satisfaction %[6]	79%	78%	77%	72%	52%	▼	83%	84%	84%	85%	85%	66%	67%	68%	69%	70%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,350	8,431	9,799	12,499	10,624	▲	8,733	8,908	9,080	9,256	9,437	10,608	10,818	11,032	11,250	11,473
		Vegetation Management - Gross Defect Correction (OCP) Cost per km $[7]	11,261	7,888	4,910	5,609	5,670	▼	3,600	3,643	3,687	2,400	2,428	3,824	3,901	3,980	4,060	4,140
		Station Refurbishments - Gross Cost per MVA in $	557,000	443,000	486,000	512,000	315,000	▼	454,000	447,000	440,000	434,000	427,000	425,000	423,000	421,000	419,000	417,000
		OM&A dollars per customer	455	430	415	415	410	▼	466	466	466	454	455	416	-	-	-	-
		OM&A dollars per km of line	4,773	4,605	4,611	4,644	4,622	▼	4,797	4,813	4,829	4,823	4,839	4,798	-	-	-	-
	System Reliability	*Number of Line Equipment Caused Interruptions*	*7,674*	*8,786*	*10,119*	*12,151*	*11,727*	▲	*8,200*	*8,000*	*8,000*	*8,000*	*8,000*	*Replaced by "SAIDI for Equipment Caused Outages"*				
		Number of Vegetation Caused Interruptions	*7,439*	*7,800*	*7,044*	*7,561*	*8,847*	▲	*6,500*	*5,800*	*5,400*	*4,700*	*4,100*	*Replaced by "SAIDI for Vegetation Caused Outages"*				
		Number of Substation Caused Interruptions	*103*	*123*	*98*	*76*	*47*	▼	*145*	*131*	*131*	*131*	*131*	*No longer being reported. Not replaced.*				
		SAIDI for Equipment Caused Interruptions	1.9	2.3	2.1	2.5	2.3	▲	*Introduced in this application*			2.0	1.9	1.7	1.6	1.5	1.5	1.4
		SAIDI for Vegetation Caused Interruptions	3.0	3.6	2.8	2.4	3.1	▼	*Introduced in this application*			2.5	2.1	1.9	1.7	1.7	1.7	1.7
		SAIDI - Rural - duration in hours	9.0	9.1	7.8	7.9	8.3	▼	8.0	7.6	7.2	6.8	6.5	5.2	4.8	4.7	4.7	4.5
		SAIFI - Rural - frequency of outages	2.7	2.5	2.4	2.7	2.8	▲	2.6	2.5	2.4	2.2	2.1	2.3	2.1	2.0	2.0	1.9
		SAIDI - Urban - duration in hours	2.7	2.5	2.6	3.2	2.7	▲	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
		SAIFI - Urban - frequency of outages	1.6	1.3	1.3	1.5	1.3	▼	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	-	1.7	2.1	1.5	1.6	▼	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Figure 4: Hydro One Distribution OEB Scorecard

Legend: 5-year trend (or all available years)

▲ up ▼ down ► flat

Hydro One target met

[5] As described in the sections that follow, the methodology for this measure was changed in 2020.
[6] Ibid.
[7] This measure is being renamed from Gross Cyclical Cost per km $ to better reflect tracking of the OCP program costs. There are no changes to the calculation methodology.

3.5.3.1 CUSTOMER FOCUS MEASURES

3.5.3.1.1 CUSTOMER SATISFACTION

3.5.3.1.1.1 CUSTOMER SATISFACTION – PERCEPTION SURVEY %

Performance Category	Measure	Description
Customer Satisfaction	Customer Satisfaction – Perception Survey %	Hydro One regularly collects customer satisfaction data through customer perception studies that are conducted by independent expert research firms. The Residential and Small Business ("R&SB") customer satisfaction survey is conducted every month among randomly selected customers who may or may not have interacted with Hydro One recently. The customer satisfaction measure captures R&SB customers' overall satisfaction with the service they receive from Hydro One. In addition, the survey includes a range of questions regarding customers' experience and satisfaction with their electricity service, allowing Hydro One to monitor how well the company meets customers' expectations and delivers on critical success factors.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	2018	2019	2020
Small Business and Residential Satisfaction (%)	66%	71%	76%	86%	87%	▲	74%	75%	75%

Small business and residential customer satisfaction has improved over the last five years, averaging 77%. Over the past three years, customer satisfaction has increased significantly, from 76% in 2018 to 87% satisfied in 2020, marking a historical high level, and exceeding Hydro One's internal targets in each of these years.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	2021	2022	2023	2024	2025	2026	2027
Small Business and Residential Satisfaction (%)	76%	76%	87%	87%	87%	87%	87%

Going forward, Hydro One aims to maintain this high level of customer satisfaction and consistently achieve an 87% satisfaction rate over the test years. Keeping customers satisfied as this level will be challenging, as customer expectations evolve and perceptions of Hydro One are influenced by outside factors, such as confidence in the sector and the price of electricity.

However, Hydro One is committed to meet customer needs and expectations and enhance the customer experience to achieve this goal.

3.5.3.1.1.2 HANDLING OF UNPLANNED OUTAGES SATISFACTION

Performance Category	Measure	Description
Customer Satisfaction	Handling of Unplanned Outages Satisfaction	This metric measures customer satisfaction with Hydro One's handling of unplanned outages. The data is collected through a transactional online survey that is sent to customers who reside in an area affected by an unplanned outage, immediately after the outage occurred. An outage satisfaction index is calculated as the simple average of three components: (1) satisfaction with communication, (2) satisfaction with time it took to restore power, and (3) satisfaction with accuracy of ETR.

Up until 2020, Hydro One used a different methodology to assess customer satisfaction with unplanned outage handling. In the past, an annual telephone survey was conducted in two waves every year. Participants represented a random sample of customers that had called into Hydro One's customer centre over the previous 12 months. Customers were asked if they have experienced an unplanned outage over the last 6 months. Respondents who answer "yes" were then asked how satisfied they were with the way Hydro One handled the most recent unplanned outage. Because of the methodology change, results before and after 2020 cannot be directly compared.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	2018	2019	2020
Handling of Unplanned Outages Satisfaction %	75%	76%	80%	78%	77%	▲	77%	78%	78%

Notwithstanding the methodology change noted above, customer satisfaction with unplanned outages has improved over the past five years, averaging 77%. In 2020, 77% per cent of customers were satisfied with the way Hydro One handled unplanned outages.

Customer satisfaction with unplanned outage handling exceeded the 77% target in 2018 by 3% and met the 78% target in 2019.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Handling of Unplanned Outages Satisfaction %	79%	79%	80%	81%	82%	82%	83%

Going forward, Hydro One aims to gradually improve customer satisfaction to 83% by 2027. This is a challenging target for Hydro to achieve, as it is higher than the levels of satisfaction that were achieved in the past. Hydro One is actively engaging in a company wide initiative to improve the outage experience for customers, and the expectation is that the improvements made to the outage handling process will be reflected in higher satisfaction levels.

3.5.3.1.1.3 CALL CENTRE CUSTOMER SATISFACTION

Performance Category	Measure	Description
Customer Satisfaction	Call Centre Customer Satisfaction	This metric measures customer satisfaction with services provided by Hydro One's call centre, which is often the first point of contact Hydro One has with a customer when they have a question or an issue that needs to be resolved. Customer satisfaction after the call is a strong indication of whether or not a customer inquiry has been addressed appropriately. This metric demonstrates that services are being provided in a manner that is responsive to customer needs. The call centre customer satisfaction survey occurs shortly after the phone call, which allows the call centre to capture timely and accurate information and to address any areas for improvement.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	2018	2019	2020
Call Centre Customer Satisfaction %	86%	90%	93%	90%	86%	▶	87%	88%	88%

Call centre customer satisfaction has remained relatively flat over the past five years, averaging 89% and has exceeded Hydro Ones internal targets for 2018 and 2019, but narrowly missed its target in 2020.

From 2017 to 2019, customer satisfaction with the call centre was above 90%, exceeding the targets for the respective years. In 2020, Hydro One narrowly missed the 88% target by 2 percentage points and ending the year four points lower than the previous. Hydro One has identified a number of reasons for this decline.

- The 2020 results are less accurate than in previous years, due to a COVID-related suspension of the survey between March and August, resulting in incomplete data for the full year.
- In March 2020, Hydro One mobilized its entire contact center operations to a work from home model in response of COVID 19 measures. During this initial period the contact center experienced increased call interaction times once staff adapted to their work from home settings, this resulted in increased customer wait times.
- In October 2020, Hydro One underwent a replacement of their telephony platform as well as its end user interfaces. Migration of the newly integrated platform was a staged approach spanning over four weeks in duration. Interaction handle times ran much higher than initially anticipated over the first three months, due to increased user adoption rates of the front-end systems.
- Over the past few years, Hydro One has invested in its communication channels to offer customers more choice and convenient options to complete transactions. This has led to a shift in the types of calls to the call centre. Simple transactions are now routinely completed via the web, or through the IVR without the need to engage a CSR. The result is a higher share of complex transactions that are handled by CSRs.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Call Centre Customer Satisfaction %	89%	89%	86%	86%	86%	86%	86%

For the test years, Hydro One aims to achieve a consistent call center satisfaction target of 86%, recognizing that the concurrent replacement of the Customer Information System (CIS) and integration of the AMI2.0 smart meters into Hydro One's billing system is likely to increase the number and complexity of calls to the call center.

3.5.3.1.1.4 MY ACCOUNT CUSTOMER SATISFACTION

Performance Category	Measure	Description
Customer Satisfaction	My Account Customer Satisfaction	This metric was is intended to measure customer satisfaction with services delivered by Hydro One's myAccount web portal. myAccount allows customers to view their bills, analyze their electricity usage, and request a number of services online, in a convenient, efficient manner. This measure captures to what extent the myAccount portal meets customer expectations.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
My Account Customer Satisfaction %	79%	78%	77%	72%	52%	▼	83%	84%	84%

Customer satisfaction with myAccount has trended downwards over the past five years, averaging 72%. Between 2018 and 2020, customer satisfaction levels have declined and fell short of the 84% target that was set in 2017. Customers cited performance and speed issues as the main reasons for low satisfaction with the myAccount portal. Hydro One understands that customers have increasingly higher expectations for digital products and services; these expectations are shaped by the experiences with other service providers and their digital solutions. Hydro One is committed to continuously improving and expanding the features of the myAccount portal over the test years to drive customer satisfaction.

To gain more actionable insights and quicker feedback from myAccount users, Hydro One has recently implemented a new transactional survey methodology to track myAccount customer satisfaction. Satisfaction tracking used to be done by an external vendor through follow-up emails that were sent with a multi-day delay. Hydro One recently implemented a software solution that uses intercept surveys to ask a random subset of users about their experience with myAccount right after they finish their transaction. This method delivers more accurate and timely estimates that allow Hydro One to react to problems in real time. This change in methodology requires an adjustment of targets going forward. Through parallel tracking of the old and new methodologies for a period of time, a mode effect was detected: over the same time period, the results from the new survey were an average of 15% lower than the results using the old methodology. Consequently, the results before 2020 cannot be directly compared to 2020 results, and future targets require a downward adjustment.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
My Account Customer Satisfaction %	85%	85%	66%	67%	68%	69%	70%

Going forward, Hydro One is making significant improvements to the myAccount portal, which are expected to be reflected in the myAccount customers' satisfaction score. Over the test years, Hydro One expects myAccount customer satisfaction to gradually increase to 70% by 2027.

3.5.3.2 OPERATIONAL EFFECTIVENESS MEASURES

3.5.3.2.1 COST CONTROL

Hydro One's customers have indicated that effective cost management and efficiency are outcomes that they value. The following metrics are designed to measure and track Hydro One's operational effectiveness.

3.5.3.2.1.1 POLE REPLACEMENT – COST PER POLE

Performance Category	Measure	Description
Cost Control	Pole Replacement – Cost Per Pole	This cost per unit metric tracks Hydro One's pole replacement unit costs. $= \frac{\text{Total Cost of Pole Replacement Program}}{\text{Number of Poles Replaced}}$

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
Pole Replacement - Gross Cost Per Unit in $	8,350	8,431	9,799	12,499	10,624	▲	8,733	8,908	9,080

Hydro One gross unit pole replacement cost has increased over the past five years, averaging $9,941. The cost of poles replacement was higher than target between 2018 and 2020. In these years Hydro One focused on replacing poor condition poles with the highest potential reliability impact if they were to fail. As a result of the RSE approach, the contribution of pole failures to the overall impact of customer interruptions has remainder relatively flat indicating that fewer customers are being impacted on average per pole failure (see DSP Section 3.2). With Hydro One's risk spend efficiency approach to business planning (DSP Section 3.7) it is expected that the highest priority poles will continue to be the primary focus for the pole replacement program in future years as well.

The 2019 pole replacement benchmarking study found that "Hydro One's pole replacement costs are comparable to the mean of the comparator group." (DSP Section 3.3 Attachment 1)

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Pole Replacement - Gross Cost Per Unit in $	9,256	9,437	10,608	10,818	11,032	11,250	11,473

The targets for the 2023 to 2027 period were based on the 2021 estimated unit cost for the pole replacement investment, inflated by inflation and incorporates efficiencies described in the SPF Section 1.4.

3.5.3.2.1.2 VEGETATION MANAGEMENT – GROSS DEFECT CORRECTION (OCP) COST PER KM

Performance Category	Measure	Description
Cost Control	Vegetation Management - Gross Defect Correction (OCP) Cost per km	This measure is the dollar cost per km of cyclical line cleared. $= \frac{Cost\ of\ Veg\ Defect\ Correction\ Program\ (OCP)}{KM's\ of\ Line\ Cleared}$

This cost per unit metric will illustrate the unit cost performance of the Optimal Cycle Protocol (OCP) vegetation management program. The OCP vegetation management strategy moves away from full right of way clearing including all trees and brush on the corridor, to a targeted defect driven approach that manages the reliability and safety risk created by incompatible vegetation growing on and along the rights of ways. There are several factors that affect the average cost per unit for vegetation management, including the density of vegetation when setting up equipment and the remoteness of the location. These factors have a significant impact on the costs related to the program which is why the average cost per unit should be viewed as a trend rather than an individual year.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	2018	2019	2020
Vegetation Management - Gross line clearing Cost per km $[8]	11,261	7,888	4,910	5,609	5,670	▼	3,600	3,643	3,687

[8] Results presented in DSP Section 3.3 and DSP Section 3.3, Attachment 2 are adjusted for inflation and therefore do not align with these results.

The three-year historical average under the new defect focused OCP strategy is showing a decrease relative to 2016 in the gross cyclical cost per kilometer of vegetation management, averaging $5,396/km. Unit cost performance in the 2018 to 2020 period was higher than the targets sets in the prior application. The 2018 to 2020 targets represent the assumptions about the OCP program held at the time of the 2017 assessment by Clear Path Utilities. The explanation for this variance is included in DSP Section 3.3 and Exhibit E-03-02, section 2.4. Clear Path noted that the unit cost projections from the 2017 Forestry Assessment report were based on information available at the time (see EB-2017-0049, Exhibit Q-1-1, Attachment 2). The performance assessment reports cite the following unanticipated factors contributed to higher than modelled unit costs in the 2017 report:

- Defect workload density was 13% higher averaged from 2018-2020 than projected.
- Higher percentage of tree removals over trims than modelled.
- Notification costs were significantly underestimated technology deployment and other significant events that lead to work stoppages.
- Brush control work on sub-transmission feeders
- Less contracted staff used for execution work than originally modelled.
- The labour costs used into the 2017 study modelled an industry standard 2-person crew with one utility arborist and one lower cost crew member.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Vegetation Management - Gross Defect Correction (OCP) per km $	2,400	2,428	3,824	3,901	3,980	4,060	4,140

Hydro One's vegetation management targets for cost per km cleared are represented in the above chart. As noted earlier, targets up to and including 2022 were set in the previous rate filing.

Hydro One's vegetation management program has made improvements with respect to cost per km and full details are explained in Exhibit E-03-02, section 2.4. The targets for the test years are based on the information outlined in the DSP Section 3.3.

3.5.3.2.1.3 STATION REFURBISHMENT – GROSS COST PER MVA IN $

Performance Category	Measure	Description
Cost Control	Station Refurbishment – Gross Cost per MVA in $	The cost per MVA only considers projects which have a station MVA of less than 10. This cost per unit (MVA) metric will demonstrate Hydro One's unit cost performance of its station refurbishment projects. Every station refurbishment project has a unique scope of work resulting in variation of the total cost for each investment. As a result this metric should be viewed as a trend over a number of years. $\$ \text{ per MVA} = \frac{\text{Total Cost}* \text{ of Station Refurbishment Investments}}{\text{Total Stations MVA Refurbished}}$

** Total Cost to include equipment, labour, overhead and removal costs. This is known as Capital and Minor Fixed Assets as per the ISD guideline.*

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	2018	2019	2020
Station Refurbishments - Gross Cost per MVA in $	557,000	443,000	486,000	512,000	315,000	▼	454,000	447,000	440,000

The station refurbishment gross cost per Mega Volta Amp (MVA) has declined over the past five years, averaging $462,600.

In 2020, the cost per MVA was better than anticipated due to installation of numerous Padmount Distribution Stations projects (PDS). This type of station design was recently implemented on the Hydro One distribution system, where the installed cost of the transformation equipment is cheaper than the installed cost of equivalent traditional distribution transformation. PDS can only be used in specific scenarios and cannot always be used to replace traditional Distribution Stations. Hydro One assesses the economic prudency and technical viability of installing a PDS in each case.

In 2019, six of the eight projects were predominantly a mix of 5 MVA traditional and Integrated Modular Distribution Stations (iMDS). The cost of iMDS projects were much higher then anticipated which yielded a poorer than expected result. In general, lower capacity traditional and iMDS type stations have a higher cost/MVA because the transformer costs are not linearly proportionate to capacity, while the installations effort and associated costs compared between smaller and larger units are relatively similar.

In 2018, some of the projects were comprehensive in nature and required more work compared to a typical transformer change out. In addition, two of the five projects were High Voltage Distribution Stations (115 kV). This resulted in a higher cost per MVA due to the incremental work of connecting equipment at non-Distribution level voltages and because equipment at higher operating voltages are considered to be Transmission rated assets are more expensive than lower rated distribution equipment.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Station Refurbishments - Gross Cost per MVA in $	434,000	427,000	425,000	423,000	421,000	419,000	417,000

The cost per MVA targets are expected to decrease by an average of 0.5% per year between 2023 and 2027. In each case, Hydro One would look to deploy the most cost efficient solution. We expect to install approximately 19 PDSs over the filing period at a lower $/MVA than previous years resulting in a decrease of the overall installed cost/MVA over the test years. While the in-year costs are subject to variability the overall costs are expected to decrease per the specified targets.

3.5.3.2.1.4 OM&A COST PER CUSTOMER

Performance Category	Measure	Description
Cost Control	OM&A Cost per Customer	$= \frac{Total\ OM\&A}{Number\ of\ Customers}$

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
OM&A dollars per customer	455	430	415	415	410	▼	466	466	466

Hydro One's average cost per customer has declined over the past five years, averaging $425, and has been lower than the 2018 to 2020 internal targets.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
OM&A dollars per customer	454	455	416	-	-	-	-

For 2023, Hydro One is targeting $416. For OM&A measures, Hydro One is not forecasting targets beyond the 2023 test year used to establish OM&A funding because OM&A levels during the remainder of the test period will be determined through the application of the Custom IR framework. Hydro One will continue to strive to work within the OEB-approved OM&A budget.

3.5.3.2.1.5 OM&A EXPENSE PER KM OF LINE

Performance Category	Measure	Description
Cost Control	OM&A Expense per KM of Line	$= \frac{Total\ OM\&A}{Number\ of\ line\ KMs}$

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
OM&A dollars per km of line	4,773	4,605	4,611	4,644	4,622	▼	4,797	4,813	4,829

The five-year cost per km of line has declined averaging $4,651, and was lower than Hydro One's internal targets.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
OM&A dollars per km of line	4,823	4,839	4,798	-	-	-	-

For 2023, Hydro One is targeting $4,798. For OM&A measures, Hydro One is not forecasting targets beyond the 2023 test year used to establish OM&A funding because OM&A levels during the remainder of the test period will be determined through the application of the Custom IR framework. Hydro One will continue to strive to work within the OEB-approved OM&A budget.

3.5.3.2.2 SYSTEM RELIABILITY

In the past, Hydro One had presented three measures as follows:

1. Number of Line Equipment Caused Interruptions
2. Number of Substation Caused Interruptions
3. Number of Vegetation Caused Interruptions

During a few years tracking for these measures, Hydro One found there were significant drawbacks in using these measures to evaluate the distribution performance for the important causes.

These three measures are highly focused on the number of interruptions without any consideration of customer impact (in terms of customer impact and duration impact).

For example, for the following cases:

Circuit	Device	Number of Interruptions	Interruption Duration (Hr)	Customer Count	Customer Interruption	Customer Hours	Total Customer Served	SAIFI	SAIDI
Feeder A	Switch 101	1	2	100	100	200	1000	0.100	0.200
Feeder A	Transformer 10001	10	1	1	10	10	1000	0.010	0.010
Total		11						0.110	0.210

Circuit	Device	Number of Interruptions	Interruption Duration (Hr)	Customer Count	Customer Interruption	Customer Hours	Total Customer Served	SAIFI	SAIDI
Feeder B	Switch 101	5	2	100	500	1000	1000	0.500	1.000
Feeder B	Transformer 10001	1	1	1	1	1	1000	0.001	0.001
Total		6						0.501	1.001

Feeder A had 11 interruptions while feeder B had 6 interruptions, but the SAIDI for feeder A is 0.210 while SAIDI for feeder B is 1.001. From number of interruption point of view, feeder A is worse than feeder B. But if we look at this from SAIDI point of view, feeder A is better than feeder B.

Using number of interruptions to measure the performance sometimes skews the results because this method does not properly normalize the results by the total customer impacts.

1. In this rate filing, Hydro One recommends using the following two measures to replace the previous number of interruption related measures (i.e. Number of Line Equipment Caused Interruptions; Number of Substation Caused Interruptions; and Number of Vegetation Caused Interruptions):SAIDI for Equipment Caused Interruptions
2. SAIDI for Vegetation Caused Interruptions

Vegetation and Equipment Failure Caused Interruptions are the two major causes for Hydro One’s distribution system reliability. As such, we are proposing to align and measure the SAIDI impact or outcome associated with equipment and vegetation caused interruptions.

These two new measures are normalized based on number of customers and better reflect the actual average customer impact.

The SAIFI/SAIDI measures for Urban/Rural and LDA measure are kept unchanged.

SAIDI FOR EQUIPMENT CAUSED INTERRUPTIONS

Performance Category	Measure	Description
System Reliability	SAIDI for Equipment Caused Interruptions	This metric is being proposed in this application as a replacement for the Number of Line Equipment Caused Interruptions. This metric tracks the SAIDI impact and outcome caused by line equipment failures on an annual basis. Over time, this measure will demonstrate Hydro One's success in improving reliability from lower incidence of equipment related failures. $= \text{SAIDI for Equipment Caused Interruptions}$

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	2016	2017	2018	2019	2020	Trend	2018	2019	2020
SAIDI for Equipment Caused Interruptions	1.9	2.3	2.1	2.5	2.3	▲	Introduced in this application		

SAIDI for equipment caused interruptions has increased over the past five years, averaging 2.2 hours.

For 2020, Hydro One's Distribution SAIDI for Equipment Caused Interruptions is 2.3 hours, which is better than 2019 (2.5 hours). This reduction has been facilitated by two main initiatives. First, by investments in Worst Performing Feeders (DSP Section 3.11, D-SS-05) which has funded the Installation of Communicating Fault Current Indicators (CFCI) and remote operable switches to minimize the duration and impact of equipment outages. Second, by focusing our discretionary System Renewal investments on replacing end of life equipment that mitigates the most reliability risk on the system.

The result for 2018 was marginally lower relative to 2019 and 2020 due in large part to a lower number of non-FM storm days that year.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
SAIDI for Equipment Caused Interruptions	2.0	1.9	1.7	1.6	1.5	1.5	1.4

The 2023 to 2027 targets were established based on the estimated year over year improvement due to the benefit from programs and investments such as Worst Performing Feeder (DSP Section 3.11, D-SS-05), Reliability Improvements (DSP Section 3.11, D-SS-02), Energy Storage Solutions (DSP Section 3.11, D-SS-04), and improved storm response and outage planning (Exhibit E-04-05, section 2.2.3).

SAIDI FOR VEGETATION CAUSED INTERRUPTIONS

Performance Category	Measure	Description
System Reliability	SAIDI for Vegetation Caused Interruptions	This metric is being proposed in this application as a replacement for the Number of Vegetation Caused Interruptions. The metric tracks the SAIDI impact and outcome for vegetation-caused interruptions on an annual basis. Visibility to the vegetation-caused interruptions allows focus to be placed on those areas with less than optimal performance. Ultimately, one of the expected outcomes and customer benefit of the vegetation management program is a reduction in vegetation-caused outages. This metric is a lagging indicator of the outcomes of the vegetation management program. $= \text{SAIDI for Vegetation Caused Interruptions}$

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
SAIDI for Vegetation Caused Interruptions	3.0	3.6	2.8	2.4	3.1	▼	Introduced in this application		

Years leading up to 2017 were demonstrating a worsening trend. There had been significant backlog of vegetation work and no expectation for this trend to change without a significant change in the vegetation management strategy. The implementation of OCP for vegetation management has resulted in a 13% improvement in vegetation caused system reliability from 2017 to 2020. It should also be noted that 2020 was an above average storm year in which

Hydro One's service territory experienced 41 storm days, excluding FM days, while Hydro One recorded on average 32 storm days annually from 2015 to 2019.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
SAIDI for Vegetation Caused Interruptions	2.5	2.1	1.9	1.7	1.7	1.7	1.7

The 2021-2027 targets were set based on the estimated SAIDI improvements due to vegetation caused interruptions as a result of OCP implementation. As Hydro One finishes its first cycle of OCP and resumes its roadside brush control program it is expected see a step reduction in vegetation caused SAIDI.

SAIDI – RURAL

Performance Category	Measure	Description
System Reliability	SAIDI - Rural	$= \frac{Total\ Rural\ Customer\ Hours\ of\ Interruption}{Total\ Rural\ Customers\ Served}$ All rural planned and unplanned interruptions of one minute or more (excluding Loss of Supply and excluding Force Majeure Events) are used to calculate this measure.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
SAIDI - Rural - duration in hours	9.0	9.1	7.8	7.9	8.3	▼	8.0	7.6	7.2

Over the past five years, rural SAIDI has improved by 8%, averaging 8.4 hours of interruptions. For 2020, rural SAIDI was 1.1 hours worse than target mainly due to 2020 being an above average storm year in which Hydro One's service territory experienced 41 storm days, excluding FM days, while Hydro One recorded on average 32 storm day annually from 2015 to 2019. 2019 performance was worse than target due to tree contacts and equipment failures. 2018 rural SAIDI was better than target.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
SAIDI - Rural - duration in hours	6.8	6.5	5.2	4.8	4.7	4.7	4.5

The 2023 to 2027 targets were established based on the estimated year over year improvement over historical performance due to the benefit from programs and investments such as Vegetation Management (Exhibit E-03-02 section 2.4), Worst Performing Feeder (DSP Section 3.11, ISD D-SS-05), Reliability Improvements (DSP Section 3.11, D-SS-02), Energy Storage Solutions (DSP Section 3.11, D-SS-04), and improved storm response and outage planning (Exhibit E-04-05, section 2.2.3).

SAIFI – RURAL

Performance Category	Measure	Description
System Reliability	SAIFI - Rural	The SAIFI-Rural metric tracks the frequency of interruptions for the rural areas only. $= \frac{Total\ Rural\ Customer\ Interruptions}{Total\ Rural\ Customers\ Served}$ All rural planned and unplanned interruptions of one minute or more (excluding Loss of Supply and excluding Force Majeure Events) are used to calculate this measure.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
SAIFI - Rural - frequency of outages	2.7	2.5	2.4	2.7	2.8	▲	2.6	2.5	2.4

Rural SAIFI has increased over the past five years, averaging 2.6 hours. 2020 and 2019 performance was 0.4 and 0.2 hours worse than target, respectively. This was mainly due to 2020 being an above average storm year in which Hydro One's service territory experienced in 41 storm days, excluding FM days, while Hydro One recorded on average 32 storm days annually from 2015 to 2019.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
SAIFI - Rural - frequency of outages	2.2	2.1	2.3	2.1	2.0	2.0	1.9

The 2023 to 2027 targets were established based on the estimated year over year improvement due to the benefit from programs and investments such as Vegetation Management (E-03-02 Section 2.4), Worst Performing Feeder (DSP Section 3.11, D-SS-05), Energy Storage Solutions (DSP Section 3.11, D-SS-04), and improved outage planning (E-04-05 Section 2.2.3).

SAIDI – URBAN

Performance Category	Measure	Description
System Reliability	SAIDI - Urban	$= \frac{Total\ Urban\ Customer\ Hours\ of\ Interruption}{Total\ Urban\ Customers\ Served}$

Distinguishing between rural and urban reliability provides a better basis for benchmarking to other utilities. The Electricity Distributor Scorecard includes the Hydro One SAIDI for the overall system. The SAIDI-Urban metric tracks the duration of interruptions for Hydro One's urban areas only and Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term, which aligns with customer expectations.

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
SAIDI - Urban - duration in hours	2.7	2.5	2.6	3.2	2.7	▲	2.8	2.8	2.8

Urban SAIDI has increased over the past five years, averaging 2.7 hours. In 2020, Urban SAIDI returned to below the target value meeting expectations. 2018 results were marginally better than target, while 2019 was 0.4 hours worse than target mainly due to issues related to equipment failures.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
SAIDI - Urban - duration in hours	2.8	2.8	2.8	2.8	2.8	2.8	2.8

The 2023-2027 targets were set up based on the objective to keep the SAIDI – Urban consistent with historical average.

SAIFI – URBAN

Performance Category	**Measure**	**Description**
System Reliability	SAIFI - Urban	The SAIFI – Urban metric tracks the frequency of interruptions for the urban areas only. $= \frac{Total\ Urban\ Customer\ \ Interruptions}{Total\ Urban\ Customers\ Served}$

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
SAIFI - Urban - frequency of outages	1.6	1.3	1.3	1.5	1.3	▼	1.5	1.5	1.5

SAIFI urban performance over the past five years has improved, averaging 1.4 interruptions. Performance over the 2018 to 2020 period was better than or on target.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
SAIFI - Urban - frequency of outages	1.5	1.5	1.5	1.5	1.5	1.5	1.5

The 2023-2027 targets were set up based on the objective to keep the SAIFI – Urban consistent with historical average.

LARGE CUSTOMER INTERRUPTION FREQUENCY LARGE DISTRIBUTION ACCOUNTS (LDAS)

Performance Category	Measure	Description
System Reliability	Large Customer Interruption Frequency Large Distribution Accounts (LDAS)	This metric tracks the total number of sustained interruptions to all LDA customers connected to Hydro One. $= \frac{Total\ Interruptions\ for\ Large\ Distribution\ Accounts}{Total\ Large\ Distribution\ Accounts\ Served}$

HISTORICAL PERFORMANCE AND VARIANCE TO 2018-2020 TARGETS

							Hydro One Targets		
Measure	**2016**	**2017**	**2018**	**2019**	**2020**	**Trend**	**2018**	**2019**	**2020**
Large Customer Interruption Frequency (LDA's) - Interruptions per LDA		1.7	2.1	1.5	1.6	▼	1.6	1.6	1.6

Over the past four years, the interruption frequency per LDA has improved to an average of 1.7 interruptions. In 2018, performance was 0.5 interruptions worse than target mainly due to transmission related interruptions for these LDAs. This situation has improved later in 2019 and 2020. In 2019 and 2020, the performance was better than or on target.

TARGETS FOR THE 2021-2027 PERIOD

	Hydro One Targets						
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	1.6	1.6	1.6	1.6	1.6	1.6	1.6

The 2023-2027 targets were set up based on the objective to keep the Number of interruptions per LDA consistent with historical average.

3.5.4 ADDRESSING THE ACTIVITY AND PERFORMANCE-BASED BENCHMARKING REPORT

On March 9, 2021, Pacific Economics Group Research LLC (PEG) published their first report on the Activity and Program Based Benchmarking (APB).[9] On June 24, 2021, the OEB revised its Filing Requirements requiring distributors applying for rates effective May 1, 2022 or later, to review the APB results and to discuss performance for each of the ten programs, along with providing any immediate remedial actions that the distributor is planning to take, based on these results and how these results will influence future planning.

Due to the timing of this Filing Requirement change relative to the filing date of this Application and finalization date of Hydro One's business planning process that underpins the Application, Hydro One is unable to discuss how the results of the APB report have influenced the 2023 to 2027 plan.

Table 1 below provides a summary of the APB report results, followed by a general discussion on the results.

[9] Pacific Economics Group Research LLC, Report to the Ontario Energy Board – New Developments in Activities and Program Benchmarking (9 March 2021, revised 11 May 2021) https://www.oeb.ca/sites/default/files/PEG-APB-Report-20210309.pdf?v=20210511

Table 1 - PEG Report Program Results and Discussion – Hydro One Cost Performance Relative to Group Results

	Cost Performance Results	Group Results	
PEG APB Program	**Average Actual Less Predicted, 2017-2019**	**Average**	**Median**
Billing O&M	71.0%	-0.7%	3.5%
Pole Maintenance O&M	464.2%	9.8%	10.5%
Lines O&M	323.9%	16.6%	7.3%
Meter O&M	69.0%	2.6%	-0.7%
Vegetation Management	140.1%	-2.2%	3.7%
Station Maintenance	-156.7%	6.6%	3.1%
Poles, Towers, and Fixtures Capex	104.7%	-0.3%	-2.9%
Distribution Stations Capex	356.0%	-16.4%	14.5%
Line Transformer Capex	-38.9%	3.5%	-3.2%
Meter Capex	106.9%	-5.4%	9.2%

3.5.4.1 DISCUSSION OF APB RESULTS

For each measure set out above, Hydro One has identified the following: those parts of its investment plan applicable to that measure, the aspects of the plan that drive beneficial cost results for ratepayers, and corresponding benchmarking results where applicable (Table 2).

1 **Table 2 - Plan Investments, Outcomes, and Benchmarking Results**

PEG APB Program	Plan Investments & Main Customer Benefits/Outcomes	Benchmarking Results
Billing O&M	**Customer Service Technology Enablement (G-GP-07) The** GSP includes investments to replace and upgrade end-of-life customer technology systems to ensure that customers have reliable access to their accounts and other resources to help them make informed decisions. Examples include the Customer Information System (CIS), which allows Hydro One to manage the customer lifecycle (move-in, start service, meter, bill, collect payments and manage filed services) for all 1.4 million Distribution customers, and the online self-service tool. Average Billing Accuracy of 98% over the planning period	Billing and Call Center Costs and Benchmarking DSP Section 3.3, Attachment • Call Centre costs at Hydro One are below the market average. • Billing costs at Hydro One are towards the lower end of the market range. • Total Call Centre and Billing spend at Hydro One is 9% below the market average. • Customer Service Representatives at Hydro One is below the peer group average. • The number of Billing FTEs at Hydro One is well below the peer group average.
Pole Maintenance O&M / Poles, Towers, and Fixtures Capex	**Pole Sustainment Program (D-SR-07)** – Replacing 51,500 wood poles (66%) and refurbishing an additional 14,000 (18%) of poor condition wood poles. Replacing 51,500 wood poles (66%) and refurbishing an additional 14,000 (18%) of poor condition wood poles	Distribution Poles and Stations Benchmarking DSP Section 3.3, Attachment 1 • Hydro One's pole replacement costs are comparable to the mean of the comparator group. • Hydro One replaces poles based upon condition and has a higher pole replacement rate (including poles replaced upon failure) as compared with comparators.

Lines O&M	Forecast Lines OM&A for 2023 is 10% lower than the 2023 figure that would result from escalating the last rebasing actual expenditure of 2018 by inflation. Outcomes of the Lines Sustainment OM&A expenditures include: • Responding to forecasted annual (2023) volumes of: • 211,500 cable locates; • 11,800 disconnects/reconnects; • 2,100 submarine cable inspections; • 14,900 line defects; and • 7,000 PCB tests;	N/A
Vegetation Management	Forecast Vegetation Management Sustainment OM&A for 2023 is 10% lower than the 2023 figure that would result from escalating the last rebasing actual expenditure of 2018 by inflation. Outcomes of the Lines Sustainment OM&A expenditures include: • Treat approximately 95% of all rights-of-ways at least once by the end of 2021; • Reactivate the road side brush control programs as the first OCP cycle is completed; and • Ensure that vegetation management prescriptions meet the OCP Defect Specifications. Average Vegetation Management Gross Defect Correction (OCP) per km of $3,981 over the planning period - a 44% decrease relative to the average actual and forecast period of 2018-2022	CNUC Vegetation Management Program Study DSP Section 3.3, Attachment 2 • HONI has a distribution system that is much more rural and remote in comparison to other utilities. This is notable because rural and remote areas are more difficult and expensive to access and manage. • HONI has a rate of removal that is three-times greater than other survey respondents. • HONI has an average program budget 2.5 times that of the Peer 2019 group, however, this disparity is largely explained by HONI's unique and challenging UVM setting. HONI has a similarly sized customer base as the Peer 2019 group but twice the number of distribution ROW kilometres.

Station Maintenance / Distribution Stations Capex / Line Transformer Capex	Forecast Stations Sustainment OM&A for 2023 is 16% lower than the 2023 figure that would result from escalating the last rebasing actual expenditure of 2018 by inflation. Outcomes of the Lines Sustainment OM&A expenditures include: • Addressing forecasted annual volumes of (2023): • 6,590 stations inspection; • Ongoing planned preventive maintenance; • 2,580 transformer oil samples, diagnostic tests, intrusive inspections and power factor tests; • 450 recloser preventive maintenance activities; • 23 station breaker preventive maintenance activities; • 50 station switches and 50 fuses preventive maintenance; • 35 MUSs will be inspected and maintained; and • Performing other station asset preventive maintenance and PCB sampling **Distribution Station Refurbishment (D-SR-04) & Lifecycle Optimization & Operational Efficiency Projects (D-SR-11)** – Replacing 118 distribution station transformers in poor condition.	Distribution Poles and Stations Benchmarking DSP Section 3.3, Attachment 1 • Hydro One has lower than average costs to replace power transformers as they are primarily comprised of smaller transformers. • Hydro One has also introduced a lower cost unfenced pad mount transformer solution for replacement of smaller substations (where feasible), which most other utilities have not considered.

	• Distribution station transformers play a key role in the safe and reliable delivery of power to distribution customers. Whereas a pole failure can be localized, a station transformer failure will interrupt power to all customers connected to that station. Proactively addressing poor condition station transformers, is expected to mitigate transformer failures and maintain the reliability of the distribution system. • Average Station Refurbishments – Gross Cost per MVA of $421,000 over the plan period - a 9% decrease relative to the average actual and forecast period of 2018-2022	
Meter O&M / Meter Capex	Forecast Meters Sustainment OM&A for 2023 is 0.9% higher than the 2023 figure that would result from escalating the last rebasing actual expenditure of 2018 by inflation. Outcomes of the Lines Sustainment OM&A expenditures include: • Ongoing inspection, testing, and maintenance of retail revenue meters; • Managing inventory for instrument transformers and metering accessories; and • Preventive and corrective maintenance for wholesale revenue meters including re-sealing and verification, trouble call response, IESO registration, and routine maintenance;	AMI Benchmarking DSP Section 3.3, Attachment 6 • Hydro One's average labour cost of $122 (excluding materials surcharge and overheads) per meter replaced is higher than the comparator average of $47. The study noted that these costs are higher than the mean of the comparator of the group because they reflect individual replacements rather than mass replacements, and because of the large, mostly low-density nature of its service territory. HONI's customer density is the lowest of the group, 23 times less dense than its closest comparator.

	Advanced Meter Infrastructure 2.0 (AMI 2.0) (D-SR-12) – Replacing AMI 1.0 (1.4 million smart meters) with a modern AMI platform. Approximately 45% of the total meter population is projected to fail by the end of the plan period. Customers expect and will continue to receive the same high level of billing accuracy. This investment ensures that customers continue to stay connected to safe reliable power, while enabling greater access to flexible service options. The modern platform, through improved network communications, will enhance end-to-end protection of customer data, while also enabling customer tools to help manage energy usage and bills.	• The study noted that Hydro One costs reflect contracted prices for low volume individual meter replacements and do not incorporate scale economies that would be expected with bulk purchases. Some of the comparators that have recently completed major meter deployments have shown lower per meter purchase costs, indicating that bulk purchases lend themselves to lower purchase costs.

The APB report contains a number of caveats with respect to the accuracy of the results and the limitation placed upon the interpretation or application of the results.

On page 5 of the APB report, PEG lists several conclusion, including:

- Inconsistent allocation of OM&A expenses has been found to be a material problem with the available data reported; and
- The efficacy of APB is better for some cost categories than others. It may make sense to focus on categories where APB is more accurate. We found that the benchmarking results had high explanatory power in 8 of the ten models and lower explanatory power in two cases (poles O&M and station capex).

On the basis of the conclusion on page 5 of the PEG report, as it relates to the two programs of Pole Maintenance O&M and Distribution Stations Capex, further discussion of the results is not warranted noting PEG's conclusion that the results for these two programs had lower explanatory power and that the APB in these cases is less accurate.

On page 9 of the APB report, PEG notes that: "…very large differences [such as ones that are ±100%] become more intuitively implausible the larger they become and suggest that other factors are needed to fully explain the observed differences." Upon reviewing the APB report, Hydro One notes that 84% of utilities have two or fewer categories programs with results that are ±100%, whereas Hydro One has seven programs with a difference between actual and predicted costs in this range. This seems to indicate that the econometric models are not appropriately calibrated for Hydro One's circumstances. Calibration is fundamental to PEG's Total Cost Benchmarking work which PEG undertakes for the purposes of stretch factors assignment. PEG makes certain adjustments to the data to ensure a higher degree of comparability among the utilities (e.g. adjusting Hydro One's cost data to remove high-voltage assets that are used to serve embedded distributors). It is not clear whether similar adjustments have been made as part of the APB report.

Page 82 of the APB report provides a list of reasons for why a distributors might perform poorly in a statistical model, including:

- Differences in accounting arising from inconsistent application of the OEB's accounting guidance in the Accounting Procedures Handbook (APH)
- Measurable business conditions of significant explanatory power not included in the econometric model
- Other random, exogenous events that are difficult or impossible to measure for all distributors

Based on the limited information provided in the report or any working papers to facilitate a better understanding of the results, Hydro One is also concerned that inconsistent data sources were used to calculate the results. Specifically, data was drawn from a variety of sources including RRR data filed on an annual basis, stand-alone data filed as part of the application process, and most recently, as part of a separate data request for APB purposes.[10] Hydro one identified in its cover letter which accompanied the APB data requested data[11] that inconsistent data sources may introduce data errors in the APB results, particularly where utilities, such as Hydro One, have undergone mergers and acquisitions during the study period. The Coalition of Large Distributors (CLD) also identified data consistency as a primary concern and one which warrants further consideration as part of the CLDs March 2019 letter to the OEB.

On the basis of the above findings in the APB report and the concerns raised by Hydro One, the validity of the results for Hydro One are unclear. A better understanding of how Hydro One's data was used, calibrated, and normalized for other random, exogenous factors is required. As such, it is difficult in the context of the APB results for Hydro One to discuss its results relative to other distributors and to propose remedial actions in this application.

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[10] EB-2017-0278, Activity and Program Based Benchmarking Initiative – Information Request, December 15, 2020
[11] Ibid.

The following attachment(s) are provided as part of this section:

- Attachment 1 – OEB Appendix 5-A Metrics

Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		1 Year 2020	5 Year Average 2015 to 2019
Cost	Total Cost per Customer[1]	903	883
	Total Cost per km of Line[2]	10,193	9,693
	Total Cost per MW[3]	51,492	52,805
CAPEX	Total CAPEX per Customer	501	465
	Total CAPEX per km of Line	5,657	5,105
O&M	Total O&M per Customer	402	418
	Total O&M per km of Line	4,536	4,588

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the
2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that
3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

Explanatory Notes on Adverse Deviations (complete only if applicable)

Metric Name:

Consistent with the application evidence and regulatory scorecards, the metrics above are based on total OM&A, not O&M.

SECTION 3.6 – DSP – OTHER CAPITAL PLANNING FACTORS AND CONSIDERATIONS

3.6.1 INTRODUCTION

DSP Sections 3.2 – 3.5 highlight many of the factors and considerations that influence the investment planning process for Hydro One's distribution system, consistent with the principles and outcomes of the OEB's RRF. These considerations include asset condition, benchmarking, productivity and continuous improvement, and performance measurement. In addition, it is important to highlight the role and significance of other factors and considerations that have influenced the development of the DSP. This section discusses in greater detail how the plan is shaped by customer needs and preferences (which underpin the development of the DSP) as well as Hydro One's obligations to plan and adapt its distribution system to accommodate evolving needs. The specific factors and considerations discussed below include:

- Customer needs and preferences as identified through customer engagement;
- Regional planning considerations and regulatory compliance;
- System modernization; and
- Distribution system losses

3.6.2 HOW THE CAPITAL PLAN REFLECTS CUSTOMER ENGAGEMENT

SPF Sections 1.6 and 1.7 provide details on Hydro One's approach to customer engagement for this rate filing. In particular, Hydro One made a dedicated effort to identify customer needs and preferences in preparation for its 2023 – 2027 investment planning process and joint rate application. This involved engaging Innovative Research Group (IRG), a third party research and consultation firm, to develop and implement a comprehensive customer engagement study. In line with best practices, IRG employed a two-phased approach, engaging customers at the beginning of the investment planning process, and again after preliminary investments options were identified. This approach allowed Hydro One to develop an investment plan that is both based on customer input, and refined based on trade-offs between specific investments.

The IRG Report incorporated feedback from a broad range of customers, with the results focused on customers' general needs and outcome preferences.[1] To achieve this, Hydro One reached out to over 48,000 distribution and transmission customers across Ontario to invite them to participate in its investment planning process. These customers participated in various types of activities, including focus groups, in-depth interviews, telephone surveys, and online workbooks. The results of this customer engagement show strong support for Hydro One's investment plan. Customers across all segments support the investments proposed in the draft plan and are willing to accept bill increases in return for these investments and associated benefits.

Throughout the planning process, Hydro One ensured the alignment of investment drivers with identified customer needs and preferences. From the candidate investment development stage through to DSP finalization, the funding status of customer flagged investments was actively monitored, discussed and considered. The final investment plan reflects the results of customer engagement while balancing system and asset needs, risk mitigation and cost impact.

For further details on how the DSP reflects the pacing of investments supported by customers as well as the type of investments identified through ongoing coordination and collaboration with customers, refer to DSP Section 3.7.

3.6.3 HOW THE CAPITAL PLAN REFLECTS REGIONAL PLANNING, REGULATORY COMPLIANCE, & SYSTEM MODERNIZATION

3.6.3.1 HOW THE CAPITAL PLAN REFLECTS REGIONAL PLANNING

As a province-wide distributor, Hydro One Distribution actively participates in regional planning activities, as its assets are located in 19 of the 21 regions that have been identified for the purpose of regional planning. Regional planning addresses supply and reliability issues at

[1] SPF Section 1.6, Attachment 1

regional and localized levels, such as the supply facilities that connect and deliver power to a group of load stations in an area or region. Regional planning generally considers the 115kV and 230kV portions of the power system that supply various parts of the province but can overlap with distribution system planning.

The roles and responsibilities of both Hydro One Transmission and Hydro One Distribution in the Regional Planning Process are discussed in SPF Section 1.2. As detailed in that section, some regions of the province have experienced significant growth, resulting in corresponding requirements to invest in the distribution system to address identified needs. In particular, the Leamington area of the Windsor-Essex region has experienced significant localized growth primarily due to the greenhouse industry, resulting in system capacity limitations. The investments listed below are those that were identified as part of regional planning and coincide with the 2023-2027 forecasting period. Since these investments were specifically identified within a Regional Planning context, they require coordination between Hydro One Transmission and Distribution.

3.6.3.1.1 SOUTH MIDDLE ROAD TS DESN #1 FEEDER DEVELOPMENT, DSP SECTION 3.11, D-SS-01

This investment is associated with the line work performed by Hydro One Distribution to construct new feeders at South Middle Road TS Dual Element Spot Network (DESN) #1. These feeders will enable the utilization of additional capacity resulting from the construction of South Middle Road TS DESN #1. The distribution scope of work will be in-serviced beginning in 2022, but will extend into 2023.

3.6.3.1.2 SOUTH MIDDLE ROAD TS DESN #2 FEEDER DEVELOPMENT, DSP SECTION 3.11, ISD D-SS-01

This investment is associated with the line work performed by Hydro One Distribution to construct new feeders at South Middle Road TS DESN#2. These feeders will enable the utilization of additional capacity resulting from the construction of South Middle Road TS DESN

#2. The development of these feeders will begin in 2022, with construction expected to be completed in 2025.

3.6.3.2 HOW THE CAPITAL PLAN REFLECTS REGULATORY COMPLIANCE

Hydro One Distribution's capital investments may be grouped into two general categories, 1) non-discretionary (mandatory) and 2) discretionary. Non-discretionary investments include those which Hydro One is obligated to make as a distributor to be compliant with applicable codes, standards, laws, or regulations and are distributed across the System Access, System Renewal, and System Service investment categories.

The subsections below provide further details on the regulatory compliance or service obligation-driven investments within this DSP. For example, the restoration of power following an outage is a mandatory requirement – Hydro One cannot decide to leave customers without power, so expenditures related to storm response are non-discretionary. By contrast, expenditures related to improving reliability are discretionary. In some cases, investments that are discretionary become non-discretionary upon asset failure. For example, pole replacements are discretionary investments, but if a pole fails, it becomes a non-discretionary investment under "Trouble Call and Storm Damage Response".

In order to meet regulatory compliance and service obligations over the 2023-2027 planning period, Hydro One Distribution anticipates total non-discretionary expenditures of $1,824M, which represents nearly 34% of the total capital envelope of $5,297M, as highlighted below. Further details are provided in DSP Section 3.8 and the respective ISDs found in DSP Section 3.11.

3.6.3.2.1 NON DISCRETIONARY SYSTEM ACCESS INVESTMENTS

3.6.3.2.1.1 JOINT USE AND RELOCATIONS (DSP SECTION 3.11, D-SA-01)

Joint use expenditures enable access to Hydro One Distributions' support structure network. Provision of access to its support structure network is required for Hydro One Distribution to be compliant with Section 22.1 of its Electricity Distribution Licence, in relation to Telecommunications attachments.

Relocation expenditures are obligated activities at the request of Municipal and Provincial road authorities, in compliance with the *Public Service Works on Highways Act* and associated Ministry of Transportation guidelines. Total expenditures under D-SA-01 are forecast to be $135M.

3.6.3.2.1.2 NEW LOAD CONNECTIONS, UPGRADES, CANCELLATIONS (DSP SECTION 3.11, D-SA-02)

To comply with Section 28 of the *Electricity Act, 1998*, and Section 7 of its Electricity Distribution Licence, Hydro One is required to provide a connection service to new industrial, commercial and residential customers when requested. Similarly, Hydro One is also required to cancel a customer's service when requested. Total net expenditures of $793M are forecast for 2023-2027 to ensure Hydro One can meet its service obligations with respect to new connections, expansions (where required to accommodate connections), and service cancellations.

3.6.3.2.1.3 CUSTOMER DEMAND DISTRIBUTED ENERGY RESOURCES (DSP SECTION 3.11, D-SA-03)

Section 6.2.4 of the Distribution System Code (DSC), and Hydro One's distribution license, mandate the connection of Distributed Energy Resources (DER) that meet the requirements of the DSC. DER activity in Ontario has shifted to behind-the-meter load displacement generators participating in the IESO's Industrial Conservation Initiative program and Ontario's Net Metering program. The Net Metering program is limited to renewable DER, and remains active and regulated by O. Reg. 541/05. Total expenditures under D-SA-03 are forecast to be $7M.

3.6.3.2.1.4 METERING SUSTAINMENT (DSP SECTION 3.11, D-SA-04)

Hydro One is required to comply with regulatory metering and billing requirements. Notably, the *Electricity and Gas Inspection Act* requires all meters be verified through a sampling program at specified intervals to ensure accurate metering. Approximately 590,000 meters, or 43% of

Hydro One's AMI 1.0 meter population will have their seals expire between 2023 and 2027 and require compliance testing (i.e. by testing a sample group) or be replaced if a sample test fails. As meters age beyond their service life and deteriorate in condition, there is also an increasing risk of non-compliance with the "good repair" requirements under the *Electricity Gas and Inspection Act* and *Weights and Measures Act.* Moreover, increasing meter failures means increased volume of field work to replace meters and/or perform unscheduled manual meter reading, which is required to comply with billing reliability standards under the Supply Service Code and DSC (e.g., issue customers no more than 2 estimated bills every 12 months, and issue an accurate bill 98% of the time in a year). To address these non-discretionary needs, total expenditures for metering sustainment within D-SA-04 are forecast to be $189M.

3.6.3.2.2 NON DISCRETIONARY SYSTEM RENEWAL INVESTMENTS

3.6.3.2.2.1 DISTRIBUTION STATIONS DEMAND CAPITAL PROGRAM (DSP SECTION 3.11, D-SR-01)

Asset failures or unplanned (reactive) system deficiencies associated with distribution station elements require an immediate response in compliance with the DSC. The activities are typically covered under the Distribution Stations Demand Capital Program, which includes the replacement of failed equipment such as transformers, reclosers, switches, and insulators, or the replacement of assets that pose a safety risk to employees or customers, such as fences and grounding systems, or reclosers with short circuit interruption ratings that have been exceeded. Total expenditures for Distribution Stations Demand Capital under D-SR-01 are forecast to be $32.

3.6.3.2.2.2 DISTRIBUTION STATIONS DEMAND CAPITAL PROGRAM (DSP SECTION 3.11, D-SR-01)

Hydro One must respond to service interruptions or other system deficiencies on an urgent basis in compliance with the section 7 of the DSC. Various situations may arise that require an emergency response by Hydro One Distribution personnel. Extreme weather or asset failures may result in a service interruption, or regular patrols and inspections may identify damaged or failed distribution assets that pose a safety hazard. During these events, Hydro One Distribution field crews must be promptly dispatched to assess and resolve these urgent issues. Total expenditures for Distribution Lines Trouble Call and Storm Damage Response under D-SR-05 are forecast to be $552M.

3.6.3.2.2.3 DISTRIBUTION LINES PCB EQUIPMENT REPLACEMENT PROGRAM (DSP SECTION 3.11, D-SR-06)

This investment is needed to manage the removal of line equipment containing PCBs in compliance with the federal PCB regulation (SOR/2008-273), which mandates the removal of all oil filled equipment whose insulating oil contains greater than 50 ppm of PCBs by the end of 2025. Total expenditures for the Distribution Lines PCB Equipment Replacement program under D-SR-06 are forecast to be $28M.

3.6.3.2.3 NON DISCRETIONARY SYSTEM SERVICE INVESTMENTS

3.6.3.2.3.1 DEMAND SYSTEM MODIFICATIONS (DSP SECTION 3.11, D-SS-03)

Demand system modifications address near-term system needs that arise from naturally occurring changes to the distribution system, which are usually caused by localized load growth. Load growth can cause a variety of issues such as power quality violations, system inefficiencies, or overloading of protection equipment. Under section 3.3 (Enhancements) of the DSC, it is the obligation of the distributor to continue to plan and build its distribution system to mitigate such issues and accommodate reasonable forecast load growth. Total expenditures under D-SS-03 are forecast to be $68M.

3.6.3.2.3.2 POWER QUALITY AND STRAY VOLTAGE (DSP SECTION 3.11, D-SS-06)

Power quality issues may arise where the voltage or phase balance of Hydro One's supply do not conform to the standards stated in its Conditions of Service. Stray voltage is a type of power quality issue where a small voltage exists between two conductive surfaces that is simultaneously contacted by a person or animal. If the voltage level is high enough, it may result in electric shock and, for farm customers, may affect livestock behaviour and health. Power quality and stray voltage complaints must be investigated, and where required, corrected, in accordance with Hydro One's Conditions of Service (see Sections 2.3.2 G and 2.3.2 H) and the sections 4.1 and 4.7 of the DSC. Total expenditures under D-SS-06 are forecast to be $20M.

3.6.3.3 HOW THE CAPITAL PLAN REFLECTS SYSTEM MODERNIZATION

Energy storage investments for grid-scale and residential storage (DSP Section 3.11, D-SS-04) are a new category of distribution investments as of this rate filing, and will be employed to provide a temporary source of backup power when the upstream supply is lost. Many of Hydro One's customers are rural and are supplied by lengthy, radial feeders that are vulnerable to prolonged outages. Since radial distribution feeders do not have an alternate source of supply, the cause of any outage must be corrected before power can be restored.

Hydro One is also continuing its multi-year program to deploy distribution automation and fault location capabilities to its feeders, also referred to as the modernization of worst performing feeders (DSP Section 3.11, D-SS-05). This program seeks to install devices at locations that contribute the most to system SAIDI. The deployment of SCADA devices for reliability improvement enables the ability of control room operators to remotely sectionalize a feeder based on the information received, and, where possible, back-feed from an alternate supply feeder. This serves to minimize not just the extent of an outage, but also the length of feeder that responding crews need to patrol to locate the problem.

As noted above, Hydro One's plan is to replace its legacy AMI 1.0 system with a new AMI 2.0 system to address end-of-life and regulatory compliance requirements. Complete details on the rationale for replacing the system can be found in DSP Section 3.2 and within DSP Section 3.11, D-SR-12. This planned replacement will also yield technological advantages and greater customer choice. In particular, the AMI 2.0 system will (i) ensure billing reliability and reduce manual meter reading costs over its service life through improved network performance, (ii) improve network reach to currently non-communicating meters providing customers with choice of RPP pricing options and (iii) yield cost savings from remote disconnect/reconnect functionality. Finally, AMI 2.0 will serve as a foundational investment to enable future customer and operational benefits that are not possible with the existing obsolete AMI 1.0 technology.

3.6.4 HOW THE CAPITAL PLAN ADDRESSES DISTRIBUTION SYSTEM LOSSES

Losses are an important consideration in the procurement of equipment and the design of distribution facilities and, as such, consideration for loss mitigation is built into Hydro One's planning, procurement and design processes such that losses are minimized over the long term.

Hydro One's distribution system transfers power from the transmission system to end-use customers. This transfer of power naturally results in losses, which generally happens in one of two ways:

1. Through transformers, which could be substation transformers that step transmission (or subtransmission) voltages down to lower distribution voltages, or customer transformers, which step distribution voltages down to end-use utilization voltages, i.e. 120/240V. Most transformer losses are caused by "no-load" losses, which are the result of magnetizing currents that are present whenever the transformer is energized. These losses cannot be avoided, and exist at all times.

2. Through lines, which are composed of subtransmission, distribution, and secondary conductor, power is passed from the transmission and distribution systems to end-use customers. Line losses occur in the distribution system as power flows from the source to the load, and are the most significant source of losses on the distribution system. The amount of losses incurred is dependent on the resistance of the line conductor per unit of length, the amount of current flowing in the line, and the length of the line. Line losses are represented by the equation: I^2R. Line losses can therefore be reduced, if either the current (I), or the line resistance (R), is reduced.

Hydro One's Distribution business reduces system losses through design and material standards, system planning and some capital investments that have a secondary benefit of reducing system losses. It is expected that these actions will have an ongoing benefit for Hydro One's system operations and efficiency, and are summarized as follows:

- All CSA transformers must meet the minimum efficiency requirements of CSA standard C802.1-13, however Hydro One exceeds this minimum efficiency standard due to its specification to minimize the Total Ownership Cost (TOC) of new line transformers. The TOC balances the upfront capital equipment cost against the ongoing cost of system losses inherent to operating transformers. Hydro One has developed a procurement specification that is specific to Hydro One's load and system characteristics to minimize the TOC.

- Hydro One has standardized its distribution designs for 15kV and 27.6kV system voltages. By standardizing designs, Hydro One enables and facilitates the cost effective future conversion of lines to higher voltages without requiring a rebuild of poles, insulators, and other associated hardware. Conversions to higher voltages results in reduced line current to deliver the same amount of power, which in turn reduces losses. As such, these standardized designs will result in a reduction of future voltage conversion costs, which will facilitate reduced I^2R system losses.

- Hydro One's planning standards specify the use of 336AL for all overhead F-Class feeders, and 556AL for M-Class feeders, on the main 3ph trunk. Larger line conductors have a lower resistance, which results in reduced losses. Although this is an effective means of reducing losses, conductor upgrade can be costly, and is usually only undertaken for capital projects where new conductor is being installed. The small incremental cost of accommodating larger conductor size is beneficial as it will result in improved voltage performance as well as an ongoing reduction of line losses.

Over the plan period, Hydro One Distribution will continue to reduce system losses through capital projects, including through the following investments:

- **Life Cycle Optimization and Operational Efficiency (D-SR-11):**

    - These investments seek to optimize system performance by removing assets where prudent. Usually, this involves removing stations with assets in poor condition through voltage conversion. These activities avoid losses associated with an additional stage of transformation, and also avoids losses by distributing electricity at a higher distribution voltage. For example, if it is economically feasible to remove a 27.6:8.32kV distribution station, by using only 27.6kV as a distribution voltage, this avoids both the DS transformer losses and the increased line losses at 8.32kV. By using a higher distribution voltage, the same amount of power can be distributed at a lower current (I).

- **System Upgrades Driven by Load Growth (D-SS-01):**

    - Load growth investments increase system capacity to accommodate new connections. The need for system capacity increases may be identified by higher than acceptable loading on existing stations and feeders. Through the construction of new assets, overloading on existing assets is reduced, which also results in a reduction of I^2R system losses by reducing the current (I).

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SECTION 3.7 – DSP – INVESTMENT PLANNING PROCESS

SPF Section 1.6 describes Hydro One's integrated system planning process, which is comprised of asset management and investment planning processes that represent a comprehensive approach for managing the utility's assets and prudently identifying and prioritizing investments. The output are detailed, multi-year investment plans (consisting of the TSP, DSP and GSP) that prudently address system and asset needs in alignment with Hydro One's strategic priorities and the customer service imperatives that are at the core of its business mandate. This planning framework strives to achieve outcomes that are consistent with the OEB's RRF and that reflect the priorities that customers value (as informed by customer engagement), as described in detail in SPF Sections 1.3 and 1.6.

This section highlights and supplements the evidence in SPF Section 1.6, further discussing the considerations that apply in the context of managing and investing in Hydro One's distribution assets.

- Section 3.7.1 provides an overview of the components that make up the system planning process.
- Section 3.7.2 discusses the strategy and context that guide planning (as detailed in SPF Section 1.6.2).
- Section 3.7.3 discusses elements of the asset management process (as detailed in SPF, Section 1.6.3) as applied to distribution assets.
- Section 3.7.4 discusses the investment planning process (as detailed in SPF, Section 1.6.4) that underpinned this DSP.

3.7.1 SYSTEM PLANNING PROCESS PHASES

Hydro One's system planning process is a robust and value-driven approach to assess system and asset-related risks, and to address those risks through investments that align with the Company's strategic priorities and objectives as well as customer needs and preferences. The process enables a consistent understanding of risk across the organization and, in this DSP, in relation to the assets that deliver electricity to 1.4 million distribution customers throughout the province. Based on this process, Hydro One is able to establish investment solutions that will cost-effectively mitigate risks over the planning period.

The system planning process includes the following three phases, which are discussed in detail in Section 1.6 of the SPF and illustrated in Figure 1 below:

1. **Strategy and Context** – Hydro One identifies long-term system needs within the context of asset condition, customer priorities, and system needs. This phase includes the first phase of the customer engagement process described in SPF Section 1.3.
2. **Asset Management** – Asset management is a lifecycle approach that balances asset needs performance, costs and associated risks during the asset's service life. This process includes the monitoring and assessment of the current state of the distribution system as well as the development of potential candidate investments.
3. **Investment Planning** – Through the investment planning process, Hydro evaluates and prioritizes candidate investments to arrive at the final DSP. As a part of this process, feedback obtained from the second phase of customer engagement is considered and reflected in trade-off decisions as appropriate.

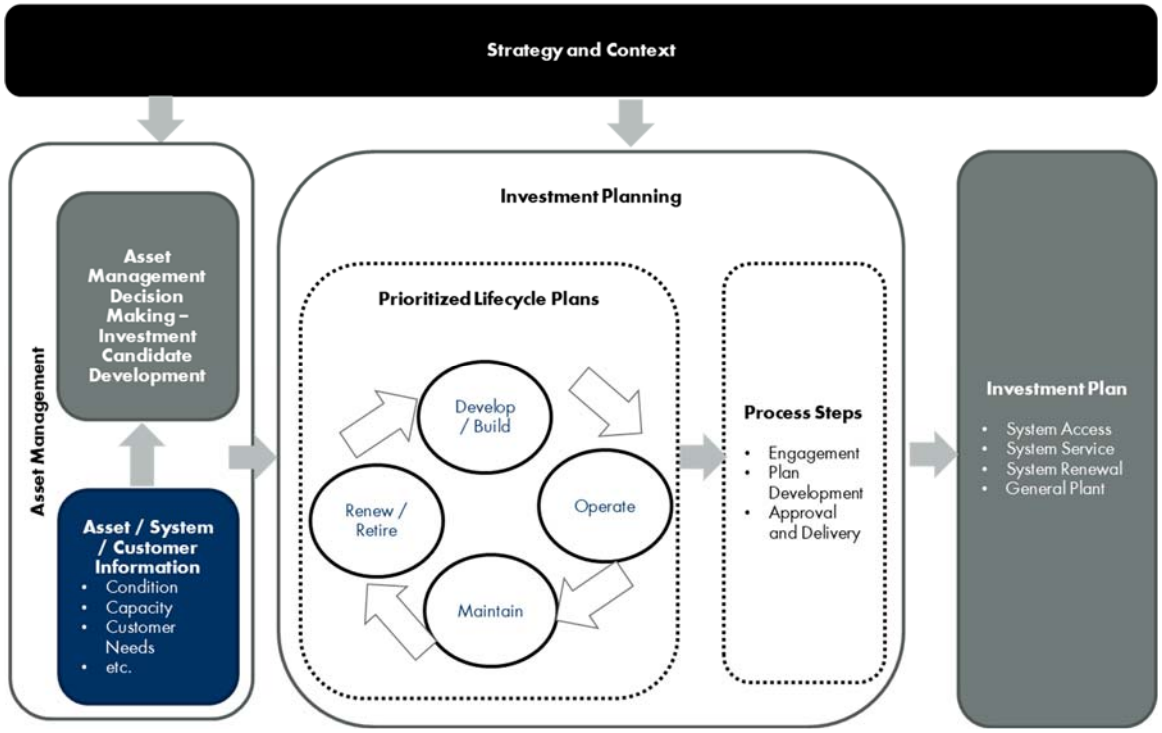

Figure 1: System Planning Process Diagram

3.7.2 STRATEGY AND CONTEXT

The DSP is informed by Hydro One's strategic priorities, as presented in **Figure 2: Hydro One's Strategic Priorities** below.

Figure 2: Hydro One's Strategic Priorities

In managing assets that are critical to customers and Ontario's economy, Hydro One is committed to meet the RRF outcomes and has integrated them into its investment planning process. The result is that the outcomes of the DSP align with the principles of the RRF with the aim to achieve the following outcomes:

- **Customer Focus:** Maintaining and improving power quality and customer reliability in response to identified customer preferences;
- **Operational Effectiveness:** Achieving top-tier safety performance and eliminating serious injuries, improving long-term reliability by modernizing the grid and mitigating risk arising from asset deterioration as well as minimizing long-term costs to maintain the distribution system;
- **Public Policy Responsiveness:** Ensuring compliance with mandated statutory and regulatory requirements; and

- **Financial Performance:** Achieving manageable and stable rate impacts over the course of the planning period.

As demonstrated through various Distribution Investment Summary Documents (see attachments to DSP Section 3.11), each investment is developed with explicit consideration for how it will achieve outcomes in alignment with the RRF.

Hydro One's planning context is influenced by customer needs, preferences and priorities. To engage with customers consistently and proactively, Hydro One undertakes extensive customer engagement activities. As described in SPF Section 1.3, these activities increase the company's understanding of customer needs and preferences so as to more effectively target outcomes that are valued by customers and plan/deliver work programs to achieve those outcomes. Customer engagement is detailed in SPF Sections 1.3 and 1.6, and also highlighted in sections 3.7.3.1 and 3.7.4.4 below.

3.7.3 ASSET MANAGEMENT PROCESS

Hydro One employs a lifecycle management approach which considers and balances asset performance, costs and associated risks during the asset's service life. By monitoring the current state of its distribution assets and identifying current and future needs, Hydro One develops a set of candidate investments, which are then evaluated and prioritized via the investment planning process (discussed in Section 3.7.4 below).

3.7.3.1 CURRENT STATE ASSESSMENT

The investments proposed in this DSP are underpinned by a thorough understanding of the current state of the distribution system, including the evaluation of actual and anticipated asset, customer, and overall system needs, along with other external factors. These assessments are described below.

ASSET NEEDS ASSESSMENT

Hydro One continuously assesses the distribution system to determine asset needs. With asset condition being the primary consideration in this assessment, Hydro One also considers other factors such as asset criticality, utilization and performance. While the age demographics of specific asset groups provide insight into long-term needs at the fleet level, age is not the primary driver for any specific investments. Information on the assessment of major distribution asset types is provided in DSP Section 3.2.

System Renewal investments are largely underpinned by asset condition data from ongoing asset needs assessment (AMI investments are underpinned by asset life expectancy instead of condition), including (i) Distribution Station Refurbishments to address transformers and other station assets that are in poor condition (DSP Section 3.11, D-SR-04), (ii) Distribution Pole Replacements to address poor condition wood poles (DSP Section 3.11, D-SR-07), and (iii) Advanced Meter Infrastructure 2.0 deployment to replace poor performing and obsolete first generation meters that are reaching the end of their service life (DSP Section 3.11, D-SR-12). In addition, a substantial portion of the System Renewal category will fund the replacement of failed or failing assets on an urgent basis (see storm and trouble response program in DSP Section 3.11, D-SR-05), which is demand-driven work that must be carried out to restore and maintain reliability of supply pursuant to Hydro One's service obligations.

CUSTOMER NEEDS

Hydro One engages with customers proactively and regularly through various mechanisms, including customer connection requests, ongoing engagement activities, and formal customer surveys. Understanding the needs of customers is critical to Hydro One's business, particularly given its diverse customer base and service territory. Hydro One's distribution system supplies approximately 1.4 million residential, commercial, industrial, and LDC customers and has more than 123,000 km of distribution circuits across different regions of the province.

Feedback from customer engagement directly informed the development of the investment plan. In 2019 and 2020, Hydro One conducted a comprehensive, two-phase customer engagement exercise in conjunction with the planning process. Feedback from Phase 1 provided valuable input for the development of initial scenarios, including indicative investment envelopes and preferred outcomes. Overall, distribution customers prioritized reasonable rates and reliable service and generally supported either investing to maintain the current system reliability or improving reliability to reduce outage frequency and duration. A clear majority of distribution customers wanted (i) a more proactive approach to replacing aging distribution infrastructure, (ii) more emphasis on helping those experiencing poor reliability, and (iii) technology investments that reduce costs, improve reliability and help customers manage electricity usage.

Customer priorities informed the derivation of investment strategies and candidate investments, including the appropriate pacing for the planning period. These initial themes and priorities were a key input for the development of the investment scenarios presented to customers in Phase 2 (with corresponding service outcomes and rate impact), allowing customers to provide feedback on trade-off options and enabling Hydro One to consider and reflect this feedback as appropriate through its investment decisions.

In addition to customer preference regarding priorities and trade-offs, specific customer needs in terms of connection to the system have directly driven the establishment of various System Access investments in this DSP, including: (i) New Load Connections and Upgrades (DSP Section 3.11, D-SA-02) and (ii) connection of Distributed Energy Resources (DSP Section 3.11, D-SA-03). The incorporation of customer feedback into the investment plan is further discussed in section 3.7.4 below.

SYSTEM NEEDS

Assessed system needs drive investments to ensure the distribution system continues to function as intended. These investments consider the thermal and short circuit capacity of system elements, regional planning requirements, restoration of service following disruptions, and reliability studies focused on maintaining – and where appropriate, improving – long-term power quality and reliability. With respect to regional planning in particular, Hydro One

Distribution plays a key role as an LDC in 19 of the 21 planning regions that provides input, data and guidance regarding regional and local distribution needs.

Several System Service investments are directly responsive to identified system needs. The largest System Service investment for the DSP planning period involves system upgrades driven to meet load growth and address local and regional capacity constraints, particularly in the Leamington area which is seeing increased load demand from greenhouse developments (DSP Section 3.11, D-SS-01). Other key investments in this category include grid modernization initiatives to improve reliability and address customers and communities that suffer from poor reliability of service (see worst performing feeders in DSP Section 3.11, D-SS-05 and energy storage solutions in DSP Section 3.11, D-SS-04).

EXTERNAL AND OTHER INFLUENCES

Hydro One leverages information regarding industry best practices, trends and benchmarking to evaluate its performance against peer utilities. These studies and comparisons generate insight regarding Hydro One's operations relative to benchmark comparators, which can guide continuous improvement efforts and inform investment decision-making. A discussion of the studies related to this DSP are included in DSP Section 3.3.

3.7.3.2 INVESTMENT CANDIDATE DEVELOPMENT

After evaluating the current state of the distribution system and identifying asset, customer, and system needs, Hydro One develops a suite of investment candidates that are assessed and prioritized through the investment planning process.

3.7.4 INVESTMENT PLANNING PROCESS

The information and data collected through the asset management process establishes the basis for evaluating and prioritizing investments and establishing the DSP. Through the investment planning process, investment candidates are assessed in terms of their total risk mitigation and risk spend efficiency and contribution to desired outcomes and are calibrated to consistently assess relevant risks across the organization, as summarized below and detailed in SPF Section 1.6.

3.7.4.1 INVESTMENT CANDIDATE LIFECYCLE RISK ASSESSMENT

For each investment candidate, Hydro One assesses the amount of risk that is expected to be mitigated across three risk taxonomies as applicable – safety, reliability, and environmental.

Each risk taxonomy features clear definitions and a consistent approach to permit a proper assessment of the risk mitigated for each candidate investment. The assessment considers both the probability and consequence of an event materializing, relying on historical data, condition information and experience to the extent possible and taking into account the total risk mitigated by each candidate investment through the comparison of the risk profile pre and post investment.

Hydro One also utilizes a "flagging" process to supplement the three risk taxonomies. Flags are used to account for special considerations and ensure stakeholder perspectives are consistently included in the evaluation of investments. For example, these flags enable the consideration of compliance driven investments, as well as investments that address specific customer priorities.

3.7.4.2 CALIBRATION

Once candidate investments have been risk assessed and flagged, candidate investments are further reviewed through facilitated calibration sessions among internal investment owners. These sessions bring together stakeholders from across the organization to discuss and compare approaches and assumptions in scoring investments, so as to ensure that the risk assessment and scoring process has been applied consistently.

3.7.4.3 PRIORITIZATION AND OPTIMIZATION

Results of the risk assessments are translated into risk scores, based on total risk mitigation, which are used to generate an initial prioritization of investments. Risk scores are normalized by estimated investment cost and used to rank investments by risk mitigated per dollar, or "Risk Spend Efficiency" (RSE). The absolute value of risks scores are also reviewed and any risks that are deemed unacceptable are reduced to an acceptable level through the inclusion of the necessary investments into the plan. Once a prioritized list is determined based on RSE, challenge sessions are held among a broad set of stakeholders to (i) review the integrated portfolio, (ii) evaluate and confirm non-risk parameters (e.g. strategic, productivity investments), (iii) assess and debate investments, and (iv) confirm trade-off decisions.

As part of these trade-off decisions, investments are promoted or demoted based on the following levers:

- Risk: augmenting the RSE prioritization by considering the risk level remaining, any unfunded investments that mitigate significant risk, as well as total/absolute risk exposure to verify that all critical risks are being addressed.
- Flags: considering investments that need to be funded due to non-risk merits.
- The consideration of both risk efficiency and risk mitigated per dollar to support prudent and data-driven trade-off decisions.

3.7.4.4 ENGAGEMENT

Following the development of the draft portfolio of investments, the draft plan is subject to two types of engagement to inform plan finalization. Internally, an enterprise engagement process is undertaken to incorporate further execution considerations. Externally, the second phase of customer engagement is undertaken to further solicit customer feedback on investment decisions. In addition to the draft plan (Scenario 2), Hydro One developed two other investment scenarios – a slower pace plan (Scenario 1) and an accelerated pace plan (Scenario 3), which took into account customer needs and preferences from Phase 1 of customer engagement and were presented for customer feedback during Phase 2.

ENTERPRISE ENGAGEMENT

Enterprise engagement ensures that the investment plan is properly reviewed and updated by the executing lines of business. This process incorporates operational and execution considerations, including resourcing, material availability, and updated cost estimates, schedules, and scope. This feedback was incorporated into the three investment plan scenarios noted above.

PHASE 2 CUSTOMER ENGAGEMENT

In Phase 2 customer engagement, the three investment scenarios were presented to customers, representing trade-off choices within Hydro One's investment plan. Scenario 1 (slower pace) prioritizes lower rate impacts by deferring the replacement of assets in poor condition to a future rate period. Scenario 2 (draft plan) sought to keep pace with and/or improve asset condition while managing costs and rate increases now and in the future. Scenario 3 (accelerated pace) involves the replacement of deteriorating assets at a faster pace, thus reducing long term risk and mitigating long term rate impacts but at a higher plan cost.

Table 1 below summarizes the distribution-related investment scenarios presented to customers.

Table 1 - Distribution Investment Scenarios Presented to Customers during Phase 2

Segment	Option	Scenario 1 (Slower Pace)	Scenario 2 (Draft Plan)	Scenario 3 (Accelerated Pace)
Distribution	1. Replacing poles in poor condition	Slow proposed pole replacement program, focusing on larger poles serving >400 customers	Replace all poles in poor condition that serve at least 100 customers	Replace all poles in poor condition that serve >30 customers
	2. Replacing poor condition station transformers	Reduce the pace of replacement, leading to high risk of outages and fleet deterioration	Maintain current approach; result in slight deterioration of fleet condition	Increase the planned rate of replacement, improving the overall fleet condition
	3. Grid modernization	Deploy smart devices to improve reliability for ~200k customers	Deploy smart devices to improve reliability for ~400k customers	Deploy smart devices to improve reliability for ~600k customers
	4. Battery Energy Storage	Deploy battery storage to improve reliability for ~500 customers	Deploy battery storage to improve reliability for ~4,000 customers	Deploy battery storage to improve reliability for ~8,000 customers
	5. Facilitating Growth	Delay community growth & economic development in rural areas, impacting reliability& power quality.	Allow new economic development to proceed, maintaining reliability and power quality.	Enable regional and economic development, maintaining reliability and power quality.
	6. Replacing Smart Meters	Not applicable. Replacing at a slower rate could lead to higher costs	Replace meters over a 7-year period	Replace meters over a 5-year period

Phase 2 provided customers with an opportunity to confirm the outcomes that they value, as well as the level of spending and mix of investments that they would like to see included in the investment plan. In general, a plurality of customers preferred the draft plan (Scenario 2) over accelerated or slower paced options, except for modernization of the distribution system, where a plurality of customers preferred an accelerated plan (Scenario 3) and distribution station transformers where customer support was split between the draft plan and the accelerated pace. This input ultimately informed the investment plan, as summarized in Table 2 below:

Table 2 - Reflection of Phase 2 Customer Feedback into the DSP

	Customer Inputs	How it appears in our investment plans	Changes as a result of Customer Engagement Study
System Access	Requirements for timely access and grid service Growth: A majority of customers across all segments prefers the draft plan over an accelerated or slower pace.	Provide customers timely access to the network through customer connection.	N/A
System Service	<u>Grid Modernization</u>: Across all customer types, the accelerated pace is the preferred option. <u>Battery Storage</u>: There is a clear preference for the draft plan, with less appetite for an accelerated pace than in previous investment.	Deliver improved reliability to our customers, pursuing safe, and cost effective solutions to meet their needs, including deployment of over 1000 smart devices/year and battery storage to support ~800 customers/year.	$86M increase to grid modernization investments to improve reliability
System Renewal	<u>Poles</u>: Across all customer types, the draft plan is the preferred option. <u>Transformers</u>: Residential customers favour an accelerated replacement pace, while business customers lean towards the draft plan. <u>Smart Meters</u>: Both residential and small business customers have a clear preference for the draft plan (7 year deployment).	Address critical asset needs, including renewing our current fleet of assets, replacing and refurbishing ~65k wood poles and replacing ~24 (between draft and accelerated plan) distribution station transformers/year consistent with customer feedback. Accelerated the replacement of smart meters to a 5 year deployment (in lieu of a 7 year horizon), in response to third party Accelerated Life Study findings.	~$10M increase to replace poor condition station transformers based on customer feedback. This increase is to a level that is greater the draft plan but less than accelerated plan.

3.7.4.5 INVESTMENT PLAN DEVELOPMENT

In developing and finalizing the investments, Hydro One incorporated feedback from Phase 2 of customer engagement. The DSP investment plan reflects customer needs and the priorities, including the respective cost-benefit considerations expressed by customers. In particular, the DSP includes an accelerated pace of grid modernization investments and a moderate increase to the pace of transformer replacements in response to customer feedback, as shown above.

For the AMI 2.0 investment, the Phase 2 Customer Engagement Program results (see DSP Section 1.3) found 36% of residential customers and 29% of commercial customers preferred the five-year pacing option while 64% of residential and 71% of commercial customers preferred the seven-year pacing option. To more effectively mitigate the higher than initially expected failure rates of AMI 1.0 meters and associated maintenance/reactive replacement costs, informed by third-party Accelerated Life Testing results (DSP Section 3.3, Attachment 5), Hydro One's plan is based on the five-year pacing option. While Hydro One places considerable weight on the customer preference for a longer seven-year pacing approach that pushes some costs out of the 2023-2027 planning period, the five-year pacing approach results in an expected $58M in total program cost savings. These savings are primarily driven by reduced corrective maintenance costs associated with AMI 1.0 meter failures as mass replacing meters is more efficient than individual reactive meter replacements.

3.7.4.6 INVESTMENT PLAN APPROVAL & DELIVERY

The final investment plan was reviewed and approved by Hydro One's Board of Directors as part of the 2023-2027 Business Plan (see Exhibit A-03-01, Attachment 1). As the plan is released to work execution teams for delivery, Hydro One closely monitors the ongoing implementation of the investment plan on a monthly basis. As unforeseen asset, system and customer needs emerge, Hydro One adapts and re-evaluates its investment plan as part of a rigorous re-direction and re-prioritization process as described in SPF Section 1.6.

SECTION 3.8 – DSP – CAPITAL EXPENDITURES – OVERVIEW

3.8.1 INTRODUCTION

This section provides an introduction to the DSP capital investment plan – DSP Section 3.9 provides a summary of historical and forecast distribution capital investments. The total capital investment plan set out in this DSP is provided in Table 1 and Figure 1, grouped by OEB investment category. A detailed description of each OEB category and its investments follows. The detailed forecasts for the General Plant investment category are provided in GSP Section 4.8.

Table 1 - Forecast Period Capital Investment Summary ($M)

OEB Investment Category	**Forecasting Period**					**% of Portfolio**
	2023	**2024**	**2025**	**2026**	**2027**	
1. System Access	239.6	240.6	227.0	212.6	204.3	**21%**
2. System Renewal	373.1	410.3	494.2	491.5	497.8	**43%**
3. System Service	196.5	169.7	229.6	192.0	205.9	**19%**
Subtotal Categories 1, 2, and 3	**809.2**	**820.6**	**950.7**	**896.1**	**908.0**	
4. General Plant (Distribution)[1]	195.9	207.4	170.1	175.5	162.9	**17%**
Total Distribution Capital	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**	
System O&M[2]	**597.5**	**-**	**-**	**-**	**-**	

[1] Details on General Plant expenditures are located in GSP Section 4.8
[2] System O&M reflects total Operations, Maintenance and Administration expenses. Further information is provided in Exhibit E-03-01. Amounts for 2024 - 2027 will be determined based on the factors identified in Exhibit A-04-03.

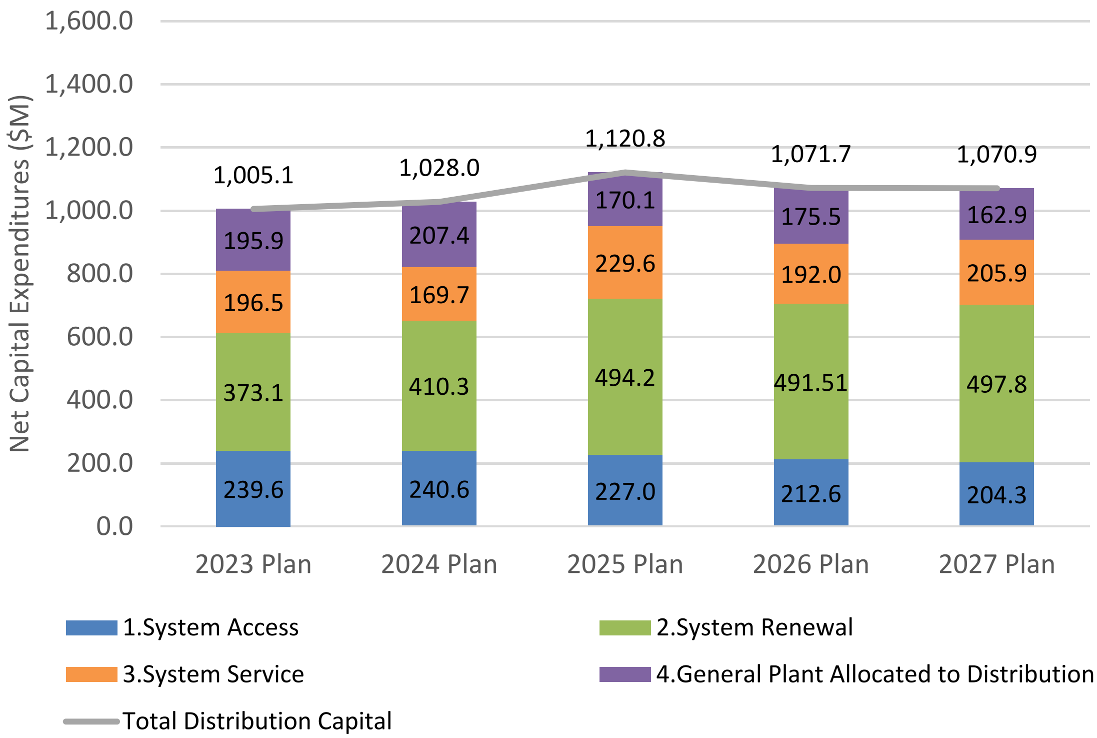

Figure 1: Forecast Period Capital Investment Summary

Hydro One developed and refined the distribution capital investment plan based on input from customers. SPF Section 1.3 details how the capital expenditure plan was impacted by, and is responsive to, customer needs and preferences.

Hydro One's capital investments are aligned with the principles in the RRF with the aim to achieve the following outcomes:

- **Customer Focus:** maintaining and improving power quality and customer reliability in response to identified customer preferences;
- **Operational Effectiveness:** Achieving top-tier safety performance and eliminating serious injuries, improving long-term reliability by modernizing the grid and mitigating risk arising from asset deterioration as well as minimizing long-term costs to maintain the distribution system;

- **Public Policy Responsiveness:** ensuring compliance with mandated statutory and regulatory requirements; and
- **Financial Performance:** achieving manageable and stable rate impacts over the course of the planning period.

Hydro One's capital investment plan was further shaped by its investment planning process, as detailed in exhibits SPF Section 1.7 and DSP Section 3.7.

3.8.2 CAPITAL INVESTMENT PLAN

This section provides the details of the proposed capital investment plan at the investment level. Additional details for each of the proposed capital investments presented below can be found in DSP Section 3.11.

3.8.2.1 SYSTEM ACCESS

Table 2 - System Access Capital Investment Summary ($M)

OEB Investment Category	Forecasting Period					% of Portfolio
	2023	2024	2025	2026	2027	
System Access	239.6	240.6	227.0	212.6	204.3	**21%**

System Access investments account for approximately 21% of the net capital investments over the five-year DSP Period, averaging about $224.8M annually.

As defined by the OEB, System Access investments are modifications (including asset relocations) to the distribution system Hydro One is obligated to perform for a customer (including a Distributed Energy Resource customer) or a group of customers to provide access to electricity services via its distribution system.

As discussed in exhibit DSP Section 3.6, investments in this category are non-discretionary and are driven by statutory, regulatory or other obligations on the part of Hydro One to provide customers with access to the distribution system. Most frequently, system access investments relate to requests by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DSP to the next depending on business conditions.

Key outcomes of System Access Investments:

- Fulfill customer requests for new connections, upgrades, or cancellations
- Fulfill third party requests for joint use attachments, and relocation of poles due to conflict with planned expansions and/or development of lands and roadways
- Replace failed meters to maintain accurate billing

Table 3 - Investments in System Access ($M)

		Forecasting Period				
ISD	**Investment Name**	**2023**	**2024**	**2025**	**2026**	**2027**
System Access						
D-SA-01	Joint Use and Relocations	24.8	29.0	27.0	26.5	27.2
D-SA-02	New Load Connections, Upgrades, Cancellations	150.7	154.6	158.5	162.5	166.7
D-SA-03	Customer Demand Distributed Energy Resources	1.4	1.4	1.4	1.4	1.4
D-SA-04	Metering Sustainment	62.6	55.6	40.1	22.2	8.9
Other	Other Distribution System Access	0.0	0.0	0.0	0.0	0.0
System Access Total		**239.6**	**240.6**	**227.0**	**212.6**	**204.3**

3.8.2.1.1 JOINT USE AND RELOCATIONS (DSP SECTION 3.11, D-SA-01)

Joint Use investments modify or upgrade Hydro One's distribution line equipment in order to accommodate the use of its equipment by third party joint use partners. These partners may include telecommunication companies (communication circuits), municipalities (street lighting - safety), local distribution companies, or generators connected to the distribution system.

Line relocation investments alter the location of Hydro One distribution line equipment in response to road modifications initiated by Road Authorities or in response to property development initiated by individual customer requests.

3.8.2.1.2 NEW LOAD CONNECTIONS, UPGRADES, CANCELLATIONS (DSP SECTION 3.11, D-SA-02)

The largest expenditures in the System Access category are related to customer connections, upgrades, and cancellations. To comply with its obligations under section 28 of the Electricity Act, 1998, Hydro One is required to provide a connection service to new industrial, commercial and residential customers when requested.

For customers that require expansion of the network in order to be connected, a discounted cash flow calculation is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection and system expansion.

For cancellations of existing service, Hydro One removes idle connection assets (such as transformers, wires and meters). Service cancellations happen in response to customer requests and for vacant premises.

3.8.2.1.3 CUSTOMER DEMAND DISTRIBUTED ENERGY RESOURCES (DSP SECTION 3.11, D-SA-03)

Investments within Customer Demand Distributed Energy Resources (DER) provide funding to modify and, as necessary, upgrade Hydro One's Distribution System to connect new DER. These upgrades are necessary to prevent equipment damage and preserve power quality to existing load customers. The DSC and Hydro One's distribution license obligate it to connect DER that meet the requirements of the DSC. The connection of DER to Hydro One's distribution system has added a significant amount of renewable energy in the Province of Ontario under various Independent Electricity System Operator (IESO) programs and the Ontario Net Metering program, which are integral to meet the energy demands of the province, as well as to support the reduction of peak demand.

3.8.2.1.4 METERING SUSTAINMENT (DSP SECTION 3.11, D-SA-04)

Metering sustainment investments ensure Hydro One has sufficient meter inventory and resources to replace failed retail and wholesale meter installations in a timely manner for reliable customer billing; to perform required sampling and reverification programs; and to perform necessary upgrades and replacement of failing metering equipment to meet regulatory requirements.

The projected levels of inventory for metering devices is based on a range of factors including historical meter device failure rates, and historic needs associated with storm and fire damage, vandalism, and manufacturer defects. The key driver of metering sustainment expenditures over the 2023-2027 period is the need to replace failing AMI 1.0 meters that are reaching the end of their service life. The number of AMI 1.0 meter failures over the test period is a function of: 1) AMI 1.0 meter failures; and 2) the pace of replacement of AMI 1.0 meters with AMI 2.0 meters (see ISD D-SR-12).

3.8.2.1.5 OTHER DISTRIBUTION SYSTEM ACCESS

Other Distribution System Access investments constitute all investments that 1) do not meet a materiality threshold of > $1M, and 2) cannot be classified within any of the System Access ISDs listed above.

Hydro One does not have any investments in this category for the 2023-2027 period.

3.8.2.2 SYSTEM RENEWAL

Table 4 - System Renewal Capital Investment Summary ($M)

OEB Investment Category	Forecasting Period					% of Portfolio
	2023	2024	2025	2026	2027	
System Renewal	373.1	410.3	494.2	491.5	497.8	**43%**

System Renewal investments account for approximately 43% of the net capital investments over the five-year DSP Period, averaging about $453.4M annually. As discussed in DSP Section 3.6, and identified below, several investments in this category are non-discretionary.

As defined by the OEB, System Renewal investments involve replacing and/or refurbishing system assets and thereby maintain the ability of Hydro One's distribution system to provide customers with electricity service.

Investments in this category are driven by asset condition and the corresponding risk of asset failure. Through Hydro One's investment planning process, outlined in SPF Section 1.7 and DSP Section 3.7, these asset-related risks and the investments that address those risks are prioritized to meet asset needs, customer needs, and system needs. This process allows Hydro One to establish investment solutions that will cost-effectively mitigate risks over the planning period.

Hydro One's discretion over the timing and priority of projects in the system renewal category may lessen over time, especially in cases where assets have a high risk of failure and/or a high consequence of failure. In contrast, Hydro One may have considerable discretion over timing and priority where deteriorating asset condition has a lower impact on performance and the consequence of asset failure is relatively low.

For this rate filing, Hydro One plans to increase system renewal investments over the forecast period in order to address deteriorating assets on the distribution system. These investments are critical to address assets in poor condition, so as to maintain overall system health. Failure to address the renewal of these assets will pose an ever increasing challenge – both for funding and for work execution – if deferred. These renewal investments vary in cost and scope, but the unique need and description of each type of investment is summarized below.

Key outcomes of System Renewal Investments:

- Asset stewardship and the prevention of asset degradation through appropriately paced replacement of poor condition assets

- Prevent or minimize service interruptions
- Maintain the safe and effective operation of the distribution system
- Maintain the reliability of the distribution system

Table 5 - Investments in System Renewal ($M)

		Forecasting Period				
ISD	**Investment Name**	**2023**	**2024**	**2025**	**2026**	**2027**
System Renewal						
D-SR-01	Distribution Stations Demand Capital Program	6.2	6.3	6.4	6.5	6.7
D-SR-02	Mobile Unit Substation Program	3.5	4.2	2.9	3.3	4.6
D-SR-03	Distribution Station Planned Component Replacement Program	4.6	3.3	1.1	1.2	1.2
D-SR-04	Distribution Station Refurbishment	44.8	41.5	28.5	32.3	32.1
D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	106.0	108.1	110.3	112.5	114.7
D-SR-06	Distribution Lines PCB Equipment Replacement Program	9.4	9.5	9.5	-	-
D-SR-07	Pole Sustainment Program	107.9	110.6	112.4	114.9	116.8
D-SR-08	Distribution Lines Minor Component Replacement Program	12.4	14.5	13.5	8.6	7.1
D-SR-09	Submarine Cable Replacement Program	12.2	12.5	12.7	13.0	13.2
D-SR-10	Distribution Lines Sustainment Initiatives	31.5	30.3	35.3	43.2	42.7
D-SR-11	Life Cycle Optimization & Operational Efficiency Projects	2.8	6.5	7.1	0.8	0.4
D-SR-12	Advanced Meter Infrastructure 2.0 (AMI 2.0)	30.9	62.0	153.7	154.4	157.3
Other	Other Distribution System Renewal	0.9	0.9	0.9	0.9	0.9
	System Renewal Total	**373.1**	**410.3**	**494.2**	**491.5**	**497.8**

3.8.2.2.1 DISTRIBUTION STATIONS DEMAND CAPITAL PROGRAM (DSP SECTION 3.11, D-SR-01)

Asset failures or unplanned system deficiencies associated with various distribution station assets (transformers, reclosers, switches, insulators, station batteries and chargers, etc.) require an immediate response by Hydro One personnel. If not rectified in a timely manner, such deficiencies and failures (including those caused or exacerbated by extreme weather) may result in significant service interruptions that require lengthy efforts to restore power, or present safety hazards to Hydro One employees or customers near the station or close to feeders protected by station equipment. The investments within this ISD primarily address the following distribution station asset needs:

- Replacement of failing or failed equipment such as transformers, reclosers, switches, insulators, station batteries, and chargers in order to maintain distribution system reliability and operation.
- Replacement of assets that pose a safety risk to Hydro One employees or customers, such as reclosers with short circuit interruption ratings that have been exceeded.

3.8.2.2.2 MOBILE UNIT SUBSTATION PROGRAM (DSP SECTION 3.11, D-SR-02)

Hydro One owns, maintains, and operates a fleet of 35 mobile unit substations (MUS), which perform an integral role in the operation of Hydro One's distribution system. MUS's are utilized for emergency power restoration in the event of a transformer or other distribution station component failure, and to offload distribution stations during maintenance and capital activities.

Hydro One maintains its MUS assets to ensure that an adequate, safe and reliable fleet is available to satisfy the requirements noted above. Without a sufficient number of available, well-maintained MUSs, Hydro One would not be able to supply customers during planned station maintenance and capital work, which is usually performed without interruption.

Over the 2023-2027 period, Hydro One plans to replace two MUS's entirely, replace the transformers on an additional six MUS's, and procure one new MUS to expand the fleet.

3.8.2.2.3 DISTRIBUTION STATION PLANNED COMPONENT REPLACEMENT (DSP SECTION 3.11, D-SR-03)

The Distribution Station Planned Component Replacement Program primarily addresses the need to replace two types of distribution station equipment that are in poor condition:

- MUS connection structures; and,
- Cooper Type "L" oil interrupter hydraulic controlled reclosers

MUS Structures provide a connection point for MUS cables to be connected and allow the station power equipment to be by-passed during planned and unplanned station maintenance and capital work. The nature of condition degradation affecting the integrity of MUS structures can vary from pole rot to animal or insect damage. If left unaddressed, MUS structures in poor condition can lengthen unplanned customer interruptions by 10 or more hours in cases where the MUS Structure must be removed and replaced with a new MUS Structure prior to the installation of an MUS to restore load to customers.

Station reclosers are required to de-energize distribution circuits under fault conditions. Hydro One plans to replace all Cooper Type L reclosers with vacuum-interrupter hydraulic controlled reclosers when they are in poor condition, or when the manufacturer recommended operation limit has been exceeded. The lifecycle cost of replacing Type L reclosers with new vacuum hydraulic reclosers is lower in comparison to the lifecycle cost of continuing to maintain Type L reclosers.

3.8.2.2.4 DISTRIBUTION STATION REFURBISHMENT (DSP SECTION 3.11, D-SR-04)

Hydro One owns, maintains, and operates 992 distribution and regulating stations and 1,197 distribution station transformers. The vast majority of these stations are a single-transformer design with limited ability to transfer load to an alternate supply during a contingency situation. Twenty percent or 237 of Hydro One's distribution station transformers are classified as being in poor condition and pose a reliability risk due to failure. Over the last five years, there has been an average of 15.6 transformer failures per year, resulting in an average of 6.6 hours of interruption for the customers supplied by those transformers. Corrective repair or planned replacement of poor condition transformers before they fail is crucial to avoid lengthy interruptions that impact a large number of customers.

Many factors lead to the degradation of a transformer's internal components over time, including transformer loading, switching, lightning surges, faults, moisture contamination, and paper insulation degradation. This deterioration and the resulting asset condition is one of the leading predictive indicators of transformer failure.

This investment involves the refurbishment of distribution and regulating stations to address station transformers and equipment identified as being in poor condition and posing a reliability risk. The proposed plan is to refurbish distribution stations throughout the five-year planning period to prevent an overall deterioration in the fleet condition. Through these investments, Hydro One aims to maintain the current level of station reliability.

3.8.2.2.5 DISTRIBUTION LINES TROUBLE CALL AND STORM DAMAGE RESPONSE PROGRAM (DSP SECTION 3.11, D-SR-05)

A number of situations may arise that require an immediate response by Hydro One Distribution personnel. Severe weather or asset failures may result in a service interruption. Regular patrols and inspections may identify damaged or failed distribution assets that pose a safety hazard. Upon such occurrences or discoveries, Hydro One Distribution field crews must be dispatched to promptly assess and resolve any urgent deficiency. Examples of the types of activities addressed under this investment include the following:

- Emergency pole and equipment replacements;
- Emergency submarine and underground cable replacements;
- Storm damage response to resolve service interruptions caused by adverse weather conditions;
- Post-trouble response (i.e., providing permanent solutions to any temporary repairs that were required during an emergency or a service interruption); and
- Damage claims, including payment for third-party damage that Hydro One Distribution cannot recover.

The trouble call and storm damage response program ensures Hydro One Distribution can continue to respond to the above listed trouble calls and service interruptions.

3.8.2.2.6 DISTRIBUTION LINES PCB EQUIPMENT REPLACEMENT PROGRAM (DSP SECTION 3.11, D-SR-06)

Oil-filled equipment manufactured prior to 1981 may contain chemical compounds known as PCBs, which are a known cancer-causing agent. This investment is needed to manage the removal of line equipment containing PCBs in compliance with Canadian Environmental Protection Act, 1999 regulation SOR/2008-273 (PCB Regulations). The legislation mandates the removal of all oil filled equipment whose insulating oil contains greater than 50 ppm of PCBs by the end of 2025. Failure to complete the mandated PCB elimination by 2025 would result in non-compliance penalties. The removal of PCB contaminated equipment is required to ensure health and safety risks are mitigated, and to ensure compliance with the PCB Regulations.

3.8.2.2.7 POLE SUSTAINMENT PROGRAM (DSP SECTION 3.11, D-SR-07)

Hydro One Distribution owns and maintains approximately 1.6 million poles, primarily consisting of wood poles (99.3%). The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, and other factors that erode their structural integrity. Once a pole has deteriorated to poor condition, it is deemed to be end-of-life and poses a high risk of failure. As outlined in DSP Section 3.2, approximately 79,000 poles are in poor condition and at high risk of failure. During the 2023-2027 period, it is expected that an additional 50,000 poles will be added to the “poor” category due to deteriorating condition.

The Pole Sustainment Program consists of three investment approaches: Test and Treat, Pole Refurbishment, and Pole Replacement. Test and Treat identifies poles that require replacement or mechanical refurbishment and will chemically refurbish the poles by treating the poles at the ground line. The Pole Refurbishment investment will restore mechanical strength by adding bracing to poles that have been determined to be in poor condition and which meet the criteria for refurbishment. The Pole Replacement investment will replace poles in poor condition that cannot be refurbished.

The pole sustainment program will result in a slight improvement in overall fleet condition and address poor condition poles that pose higher reliability risk in order to help maintain reliability and reduce the number of potential interruptions to customers. Additionally, chemically retreating poles proactively will result in mitigation of ground line rot and prevent further deterioration of poles at the ground line which is expected to extend pole life.

3.8.2.2.8 DISTRIBUTION LINES MINOR COMPONENT REPLACEMENT PROGRAM (DSP SECTION 3.11, D-SR-08)

These investments involve the replacement of a number of minor distribution lines components that are not specifically addressed under other lines-related distribution capital investments. They include the replacement of cross arms in poor condition, the replacement of substandard and obsolete transformers, the installation of bird nest platforms, and the replacement of failed sentinel lights. The triggers for these investments are condition (in the case of cross arms), obsolescence (in the case of substandard transformers), and compliance (in the case of nest platforms and sentinel lights). These investments are expected to maintain reliability and meet Hydro One's obligations with respect to maintaining sentinel lights.

3.8.2.2.9 SUBMARINE CABLE REPLACEMENT PROGRAM (DSP SECTION 3.11, D-SR-09)

Hydro One's distribution system contains approximately 12,000 submarine cable installations, primarily used to supply island dwellings or to substitute for overhead water crossings when these are not technically or economically feasible. Due to the nature of their installation, submarine cables are especially prone to damage and corrosion where they enter a body of water. This damage is of special concern if it occurs at a location which can be accessible to the public and can pose serious health and safety risks.

Submarine Cable Replacement investments involve the replacement or refurbishment of submarine cables when they are found to be damaged or exposed. The need to address each installation is based on the condition assessment of the individual cable. These investments are expected to reduce the public safety risk due to damaged or exposed cables, as well as maintain reliability by preventing unplanned interruptions to customers from defective cables.

3.8.2.2.10 DISTRIBUTION LINES SUSTAINMENT INITIATIVES (DSP SECTION 3.11, D-SR-10)

The Distribution Lines Sustainment Initiative addresses (1) overhead feeder sections that contain a large proportion of end-of-life assets based on their condition and, as a result, require rebuilding and often relocation from off-road locations to road side, and (2) underground feeders where cable condition warrants cable injection. The need to perform these investments is based on asset condition. These investments propose to address sections of feeders that have been identified to be in poor condition in a coordinated manner to maintain reliability of the feeder, and in the cases of relocation of off-road sections to road side, improve reliability.

3.8.2.2.11 LIFE CYCLE OPTIMIZATION AND OPERATIONAL EFFICIENCY PROJECTS (DSP SECTION 3.11, D-SR-11)

Hydro One typically replaces assets in poor condition on a like-for-like basis, but in some cases, assets in poor condition can be eliminated rather than replaced, while still meeting system needs to maintain capacity, reliability, and operability. In cases where eliminating assets is a cost effective alternative, it is considered a life cycle optimization investment. The scope of work for investments of this nature most often involve a system reconfiguration or voltage conversion.

3.8.2.2.12 ADVANCED METER INFRASTRUCTURE 2.0 (DSP SECTION 3.11, D-SR-12)

The Advanced Metering Infrastructure 2.0 program (AMI 2.0) is a multi-year investment to replace Hydro One's legacy AMI 1.0. Hydro One began the installation of its AMI 1.0 system in 2007 in accordance with the direction of the Province of Ontario. The service life of AMI 1.0 meters is approximately 15 years. This anticipated service life is substantiated by AMI 1.0 meter failures, with failures doubling between 2017 and 2020. Projections of future meter failures, based on independent Accelerated Life Testing results, estimate approximately 579,000 meters (45% of the total meter population) are expected to fail by the end of 2027. Hydro One's AMI is critical to ensure reliable billing for its approximately 1.4M retail customers, and to maintain regulatory compliance.

The AMI 2.0 program, spans the pre-test, test, and post test periods and is organized in three sequential phases: Pre-Deployment RFP (2020-2021); Planning, Head End System, and Pilot (2022-2023); and Mass Meter Deployment (2023-2028). The program will employ the newest generation of equipment to meet current needs and provide a platform to address foreseeable future needs over the investment's service life.

3.8.2.2.13 OTHER DISTRIBUTION SYSTEM RENEWAL

Other Distribution System Renewal investments constitute all investments that 1) do not meet a materiality threshold of > $1M, and 2) cannot be classified within any of the System Renewal ISDs listed above.

3.8.2.3 SYSTEM SERVICE

Table 6 - System Service Capital Investment Summary ($M)

OEB Investment Category	Forecasting Period					% of Portfolio
	2023	2024	2025	2026	2027	
System Service	196.5	169.7	229.6	192.0	205.9	**19%**

System Service investments account for approximately 19% of the net capital investments over the five-year DSP Period, averaging about $198.7M annually. As discussed in DSP Section 3.6, and identified below, in this category Demand System Modifications and Power Quality and Stray Voltage investments are non-discretionary.

As defined by the OEB, system service investments are modifications to Hydro One's distribution system to ensure that the system continues to meet operational objectives while addressing anticipated future customer electricity service requirements.

Investments in this category are driven by reliability-focused initiatives, or in response to capacity or operational constraints caused by load growth.

Key outcomes of System Service Investments:

- Reduce outage impacts through improved sectionalizing, feeder ties and energy storage solutions
- Meet capacity needs in areas of load growth
- Maintain acceptable performance of the distribution system by addressing power quality and stray voltage issues

Table 7 - Material Investments in System Service ($M)

		Forecasting Period				
ISD	**Investment Name**	**2023**	**2024**	**2025**	**2026**	**2027**
System Service						
D-SS-01	System Upgrades Driven by Load Growth	98.2	76.3	127.5	76.1	100.2
D-SS-02	Reliability Improvements	7.3	0.1	6.5	18.6	7.5
D-SS-03	Demand System Modifications	13.2	13.4	13.7	13.9	14.2
D-SS-04	Energy Storage Solutions	34.3	35.0	35.6	36.3	36.0
D-SS-05	Worst Performing Feeders	39.6	40.9	42.2	43.0	43.8
D-SS-06	Power Quality and Stray Voltage	3.8	3.9	4.0	4.0	4.1
Other	Other Distribution System Service	0.1	0.1	0.1	0.1	0.1
System Service Total		**196.5**	**169.7**	**229.6**	**192.0**	**205.9**

3.8.2.3.1 SYSTEM UPGRADES DRIVEN BY LOAD GROWTH (DSP SECTION 3.11, D-SS-01)

Load Growth investments address system capacity issues that arise as a result of changes to the distribution system caused by regional load growth. System capacity constraints that are caused by regional growth result in system issues characterized by power quality complaints, system inefficiencies, or thermal constraints (where system elements are being operated near, or above, their rating)

In accordance with Section 3.3 (Enhancements) of the DSC, Hydro One is required to plan and build its distribution system to accommodate reasonable forecast load growth. Therefore, Hydro One Distribution plans and executes enhancement projects to improve system operating characteristics and relieve system capacity constraints. Load growth investments cover system upgrades that are needed in response to regional growth trends requiring significant capital expenditure, scope, and lead time to address the identified capacity constraint, and may involve the upgrade of existing stations or feeders, construction of new stations or feeders, or conversion of feeders (or feeder sections) to higher voltages.

3.8.2.3.2 RELIABILITY IMPROVEMENTS (DSP SECTION 3.11, D-SS-02)

Hydro One's distribution system is typically planned based on a radial supply, as this is the most cost-effective means of distributing electricity to end-use customers. A radial design, however, does not have an alternate source of power in the event of an outage. As a result, when an outage occurs on a radial feeder, workers must physically locate the fault, and remedy the cause of the outage before power can be restored.

Reliability Improvement investments are focused on improving reliability through remote load transfer capability, resulting in reduced outage durations. Since each distribution feeder is unique, the optimal solution to enable load transfers depends on the existing load transfer limitations. The investments within this ISD overcome these limitations through one of two means:

1. Addition of feeder ties: To minimize the duration of an outage experienced, customers can be temporarily supplied from an alternate source as the faulted section of line is addressed.
2. Improved backfeed capabilities: In some cases feeder ties exist, but are limited in their ability to backfeed customers due to resulting voltage levels or loading limitations of equipment or protection devices. Improvements to address these issues could be increased conductor size or the addition of voltage regulators.

3.8.2.3.3 DEMAND SYSTEM MODIFICATIONS (DSP SECTION 3.11, D-SS-03)

Demand system modifications address near term system needs that arise as a result of localized growth on the distribution system, resulting in equipment overload or power quality issues. System modifications may be reactive, in response to urgent issues such as power quality complaints, or may be proactive, in response to anticipated issues caused by forecast customer connections, and are required to enable continued growth in localized areas.

3.8.2.3.4 ENERGY STORAGE SOLUTIONS (DSP SECTION 3.11, D-SS-04)

Energy Storage is a means of improving reliability for customers who experience long interruption durations. Feeder sectionalization has traditionally been used to minimize the overall impact of an outage on the main trunk of the feeders. Unfortunately, for customers who reside at the furthest extents of a distribution feeder, sectionalization is unable to improve reliability performance or speed of restoration. By design, when feeder protection sectionalizes, it cuts power for all downstream customers in order to maintain continuity of supply to upstream customers. Therefore, these vulnerable customers who are at the tail end of the feeder will experience the outage until the cause of the outage can be identified and corrected.

In recent years, increasing needs for system flexibility and reliability, combined with rapid decreases in the costs of battery technology, have enabled battery energy storage systems to play an increasing role in power systems across the world. Battery storage is a DER that can be used as a temporary source of energy during a system outage, and can be designed to pick up load on a feeder section when there is an interruption to the upstream power supply.

Hydro One plans to invest in battery storage that is scaled to fit the reliability needs of a specific area, with solutions varying from the installation of residential storage batteries in a customer's home, to grid-scale storage systems that can back up a whole community.

3.8.2.3.5 WORST PERFORMING FEEDERS (DSP SECTION 3.11, D-SS-05)

Hydro One customers on average have experienced about 15 hours of outage annually from 2011 to 2020, including all major weather events and loss of upstream transmission supply. Long duration of outages impact customer's negatively interrupting the regular flow of life, prevents business from providing normal service to their customers, and result in manufacturing delays and potential product loss.

This investment focuses on 500 feeders with the highest average contribution to SAIDI. Historically, these 500 feeders contribute a quarter of Hydro One's overall SAIDI. Improving performance of this group of feeders is expected to reduce the average duration of outages by over 40% for about 600,000 customers. Performing these investments will enable Hydro One to reduce the duration of outages through the following solutions:

- Deployment of modern switching equipment that can be remotely controlled to provide isolation and sectionalization;
- Adding monitoring and remote control to existing equipment capable of supporting SCADA, which will enable faster response to outages when they occur;

- Installing remote operable switches at existing tie points to enable faster load transfers; and
- Installation of Communicating Fault Current Indicators (CFCI), which will identify the fault location to system operators to enable faster mobilization and restoration by field personnel.

3.8.2.3.6 POWER QUALITY AND STRAY VOLTAGE (DSP SECTION 3.11, D-SS-06)

Power Quality and Stray Voltage investments respond to customer complaints resulting from power quality and stray voltage issues, with the goal to investigate and perform necessary corrective work in compliance with sections 4.1 and 4.7 of the DSC. Power quality issues can include high voltage, low voltage, phase imbalance, and voltage flicker. Stray voltage concerns can be residential or farm.

Hydro One performs a number of measures to resolve power quality and stray voltage concerns, including examination of the integrity of neutral and grounding systems, balancing loads and upgrading the neutral conductor of the supply system.

3.8.2.3.7 OTHER SYSTEM SERVICE

Other Distribution System Service investments constitute all investments that 1) do not meet a materiality threshold of > $1M, and 2) cannot be classified within any of the System Service ISDs listed above.

3.8.3 IMPACT OF CAPITAL INVESTMENTS ON OPERATIONS, MAINTENANCE AND ADMINISTRATION EXPENDITURES

OM&A expenditures are influenced by a variety of factors, including regulatory requirements, customer-driven requests, maintenance cycles and the number, age, and condition of various asset populations. While in some cases, capital expenditures may result in a corresponding increase or decrease in OM&A expenditures, there are a number of areas where there is not a direct relationship between OM&A and capital expenditures. This section provides an overview of where capital expenditures may influence OM&A, and identifies if OM&A is expected to increase, decrease, or remain at historic levels as a result.

The forecast Distribution Sustainment OM&A expenditure for 2023 is $311.4M, which is $34M, or 10%, lower than the 2018 actual expenditure escalated by inflation ($345.1M). Some of the capital expenditures proposed in this plan have allowed Hydro One to maintain or reduce sustainment OM&A expenditures and without these investments sustaining OM&A costs would increase.

Hydro One manages its Distribution Sustainment OM&A by dividing the expenditures into the following four investment categories: 1) Stations, 2) Lines, 3) Meters, Telecom & Control and 4) Vegetation Management. The potential impact of capital expenditures on each of these categories is discussed below.

3.8.3.1 STATIONS

These OM&A expenditures, forecasted to be $20.2M in total for 2023, fund the work required to inspect, repair or maintain distribution stations or individual station components, as well as assess and carry out remedial work to reduce environmental contamination at distribution stations. Overall, planned capital investments will put upward pressure on stations OM&A costs over the plan period, as investments that result in OM&A savings by reducing the number of stations are offset by new OM&A expenditures required to maintain new stations and future energy storage systems. Since OM&A expenditures for energy storage systems will not be incurred until these systems are in-service, these expenditures are not reflected in the 2023 Sustainment OM&A forecast. Not proceeding with capital investments in some cases will result in increased Stations OM&A costs. Expenditure categories for Stations Sustainment OM&A are further discussed in the following sections.

3.8.3.1.1 INSPECTIONS AND PLANNED PREVENTIVE MAINTENANCE

Inspections and planned preventive maintenance accounts for $7.8M in 2023. Inspection and testing of station equipment is performed to monitor asset condition and to identify asset deficiencies. The need for, and frequency of, station inspections are mandated by the DSC, Appendix C, and are independent of plant age or condition. Planned preventive maintenance includes time based activities, such as oil testing and thermal vision inspections, which are performed independent of plant age or condition. It also includes maintenance activities tied to asset condition such as diagnostic testing of transformers where warranted.

Inspections and planned preventive maintenance costs are directly correlated to the number of stations and station transformers in the system. As described below the number of stations and transformers will not materially change over the plan as a decrease in stations through investments within Life Cycle Optimization and Operational Efficiencies (DSCP Section 3.11, D-SR-11) will be offset by increases in stations and transformers driven by System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01) investments. Energy Storage Solutions (DSP Section 3.11, D-SS-04) investments will put upward pressure on inspections and planned preventive maintenance expenditures as Hydro One plans to install battery energy storage systems over the course of the 2023-2027 period. Overall, planned capital investments are anticipated to put upward pressure on inspections and planned preventive maintenance expenditures over the plan. Additional details on the relationship between inspections and planned preventive OM&A and Capital are provided in the breakdown below.

1. **Life Cycle Optimization and Operational Efficiencies (DSP Section 3.11, D-SR-11)** addresses poor condition stations by eliminating those stations through voltage conversion or load transfers. These investments are expected to decrease inspection and planned preventive maintenance costs since the investment results in the removal of a station, and cyclical inspections and planned preventive maintenance will no longer be required. Over the course of the 2023-2027 capital plan, these investments will result in a reduction of 10 stations.

2. **System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01)** addresses station capacity through new or upgraded stations, in response to system needs driven by load growth. Since these investments may result in the construction of a new station (or expansion of existing station), they are expected to increase station inspection and preventive maintenance costs. The construction of a new station will require cyclical inspections to maintain regulatory compliance, and increased preventive maintenance requirements such as oil tests or diagnostic tests. Over the course of the 2023-2027 capital plan, load growth investments will result in an increase of 8 new distribution stations, and 4 new stations transformers that will be added to existing sites.

3. **Energy Storage Solutions (DSP Section 3.11, D-SS-04)** address poor reliability through a temporary backup from a battery energy storage system (BESS). These investments are expected to increase inspection and preventive maintenance costs, since large scale battery energy storage system installations require preventive maintenance and inspections, and will therefore represent an increase in inspection requirements. Over the course of the 2023-2027 capital plan, these investments will result in an increase of 20 BESS sites.

4. **Distribution Station Refurbishment (DSP Section 3.11, D-SR-04**) addresses station transformers and equipment in poor condition on a planned basis. The proposed level of Distribution Station Refurbishments will not have an impact on inspections OM&A as these are not condition based, but by addressing poor condition assets it is expected that station refurbishments will maintain preventative maintenance OM&A forecasts. A decrease of station refurbishments from the proposed levels would be expected to result in increased preventive maintenance costs as a result of increased diagnostic testing on poor condition transformers.

5. **Distribution Station Planned Component Replacement (DSP Section 3.11, D-SR-03**) addresses poor condition station assets such as MUS structures and Cooper Type L oil hydraulic reclosers. These proposed capital component replacements will not have an

impact on inspection or preventative maintenance OM&A forecasts, since these OM&A costs are cyclical and not influenced by asset condition.

3.8.3.1.2 CORRECTIVE MAINTENANCE

Corrective maintenance expenditures account for $11.5M in 2023. These investments provide funding to respond to emergency failures and to address equipment deficiencies identified through inspections. Distribution Station Refurbishment (DSP Section 3.11, D-SR-04) are expected to maintain the level of corrective maintenance needed by maintaining the overall condition of the fleet of distribution stations over the plan. Distribution Station Planned Component Replacement (DSP Section 3.11, D-SR-03) investments are expected to decrease maintenance costs by installing vacuum reclosers that require less corrective maintenance. This expected decrease in OM&A has been incorporated into the 2023 corrective maintenance expenditures and these savings are expected to be maintained over the plan. Therefore, capital investments are needed to maintain the 2023 level of corrective maintenance expenditures over the plan. Additional details on the relationship between corrective maintenance OM&A and Capital are detailed below.

1. **Distribution Station Refurbishment (DSP Section 3.11, D-SR-04**) addresses stations transformers and equipment in poor condition on a planned basis. The proposed level of Distribution Station Refurbishments are expected to maintain station corrective maintenance costs at historic levels. Poor condition transformers that are not replaced through a station refurbishment project must be addressed through corrective maintenance. The average corrective repair cost for a poor condition transformer is approximately $77,000. Furthermore, when older poor condition transformers are not replaced, they may require multiple corrective repairs over time as more components are expected to fail and need to be addressed. As a result, a decrease in the proposed number of station refurbishment projects would result in an increase in corrective maintenance expenditures.

2. **Distribution Station Planned Component Replacement (DSP Section 3.11, D-SR-03)** addresses specific station protection devices (Cooper Type L reclosers) that are in poor condition, or when the manufacturer recommended operation limit has been exceeded. This investment also addresses the replacement of MUS Structures that are used for connecting an MUS, which enable OM&A and capital work in stations without customers being interrupted. Distribution Station Planned Component Replacement are expected to decrease overall station corrective maintenance costs and this decrease has been incorporated into the 2023 corrective maintenance expenditures. Vacuum interrupter reclosers have lower maintenance costs than oil interrupter reclosers. If oil interrupter reclosers are not replaced through the planned component replacement investment, then they must be addressed through corrective maintenance. Therefore, a decrease in oil interrupter recloser replacements would result in an increase in corrective maintenance expenditures. OM&A expenditures for MUS Structures have historically been minimal and will not influence corrective OM&A expenditures.

3.8.3.1.3 LAND ASSESSMENT AND REMEDIATION

Land assessment and remediation expenditures account for $1.0M in 2023, to test and carry out remedial work required to manage contaminated soil at stations. Since soil contamination is typically caused by the historical usage of herbicides and insulating oil (PCBs) that are no longer approved, there is no impact on soil testing or contamination that would result from capital expenditures.

3.8.3.2 LINES

Distribution Sustainment Lines OM&A expenditures, forecast to be $132.0M in 2023, fund the operations, maintenance, and administration costs related to distribution lines assets, with approximately half of these expenditures related to Trouble Calls. Overall, planned capital investments will not have material impact on Lines Sustainment OM&A costs over the plan period, but in some cases may create slight upward or downward pressures. The impacts from capital expenditures on Distribution Sustainment Lines OM&A, where a potential relationship exists, are detailed further below:

3.8.3.2.1 TROUBLE CALLS

OM&A Trouble Calls represent $63.9M of the overall Distribution Sustainment Lines OM&A forecast expenditures in 2023. These expenses address the restoration of service due to unplanned power interruptions. Such unplanned interruptions are largely due to contact with vegetation or line component failures, which are not capitalized. Vegetation related trouble calls are not impacted by capital expenditures in the plan, as the vegetation management program is also an OM&A expenditure. Trouble Call OM&A costs may be decreased by capital investments that replace cross arms or poles, since the performance of these activities also renew the condition of other line components such as insulators. Since the overall condition of Hydro One's distribution system line component population will not materially change as a result of these capital expenditures, it is not expected to have a material impact on total Trouble Call OM&A. Specific capital investments that may influence Trouble Call OM&A expenditures are discussed in more detail below.

1. **Distribution Lines Minor Component Replacement Program (DSP Section 3.11, D-SR-08)** involves the replacement of a number of minor distribution lines components, including cross arms, substandard and obsolete transformers, and sentinel lights, as well as the installation of bird nest platforms. With the exception of cross arm replacements, these investments are expected to have no material impact on OM&A trouble call expenditures, as unplanned replacement of these assets are capital expenditures and not addressed under OM&A trouble calls. While OM&A trouble call costs are anticipated to be lower for new cross arms, since replacing cross arms will also renew the condition of other hardware attachments such as insulators, the overall condition of line components will not materially change over the plan period. As a result, this investment is not expected to have a material impact on OM&A trouble call expenditures.

2. **Pole Sustainment Program (DSP Section 3.11, D-SR-07)** funds pole replacement and the mechanical and chemical refurbishment of poles. While OM&A trouble call costs are anticipated to be lower for new pole installations, the overall pole population condition will not materially change over the plan period. As a result, this investment is not expected to have a material impact on OM&A trouble call expenditures.

3. **Submarine Cable Replacement Program (DSP Section 3.11, D-SR-07)** funds the replacement of submarine cables or installation of mechanical protection of damaged or exposed submarine cables. This work is expected to have no impact on OM&A trouble call costs as addressing submarine cable deficiencies is a capital expenditure and not addressed under OM&A Trouble Calls.

3.8.3.2.2 UNDERGROUND CABLE LOCATES

Underground Cable Locates represent $13.4M of the overall Distribution Sustainment Lines OM&A forecast expenditures in 2023. This program addresses customer requests for locating and marking Hydro One underground plant for customers and contractors who request this information, and as a result is largely independent from capital investments on Hydro One's distribution system. Although the installation of new underground plant through new subdivision developments under New Load Connections, Upgrades and Cancellations (DSP Section 3.11, D-SA-02) will put upward pressure on underground cable locate costs, the impact is not expected to be material, since the percentage change of total underground cable on the distribution system is not significant. The anticipated changes to OM&A costs will therefore not be materially impacted by capital expenditures.

3.8.3.2.3 DISCONNECTS / RECONNECTS

Disconnects / Reconnects represent $16.4M of the overall Distribution Sustainment Lines OM&A forecast expenditures in 2023. This program addresses customer requests for the isolation of customer owned assets from the distribution system. Capital investments for New Load Connections, Upgrades and Cancellations (DSP Section 3.11, D-SA-02) can increase these OM&A costs as more customers connect to the system. However, the impact is not expected to be material as the percentage of new connections added does not materially impact customer count totals for the overall system. Capital expenditures are therefore not expected to have a material impact on OM&A costs for Disconnects / Reconnects.

3.8.3.2.4 LINE MAINTENANCE

Line Maintenance represents $13.3M of the overall Distribution Sustainment Lines OM&A forecast expenditures in 2023. These expenditures address the inspection of underground and submarine assets, corrective maintenance on all overhead, underground, and submarine assets, and preventive maintenance on overhead switches and insulators.

Inspection OM&A costs are associated with six-year or three-year inspection cycles to comply with Regulatory requirements, and are dependent on the number of distribution lines assets rather than the condition of those assets. Corrective OM&A costs are focused on the repair and replacement of minor defective components that have been identified during line patrols.

Capital programs that increase the number of distribution assets will create upward pressure on Inspection OM&A costs, as more assets will need to be added to inspection cycles. In contrast, capital programs that replace or rebuild assets, which may address previously identified defects, will create downward pressure on Corrective OM&A costs. These impacts of capital on OM&A expenditures are not anticipated to be material on a system level, as Hydro One's capital programs will not materially change the condition of the distribution system over the plan period. The potential impact of capital programs on specific assets or specific line sections are further discussed below.

1. **Pole Sustainment Program (DSP Section 3.11, D-SR-07), Distribution Lines Minor Component Replacement Program (DSP Section 3.11, D-SR-08),** and **Submarine Cable Replacement Program (DSP Section 3.11, D-SR-09)** fund the replacements or refurbishment of various overhead and underground equipment and submarine cables. These investments will have a neutral impact on Lines Corrective Maintenance OM&A costs. While corrective maintenance costs are anticipated to be lower for new poles, cables and components from a fleet perspective, at the proposed rate of replacement the overall condition of the system is not expected to materially change over the plan period. Thus, the overall equipment population condition is not sufficiently impacted to make a material difference on maintenance costs.

2. **Distribution Lines Minor Component Replacement Program (DSP Section 3.11, D-SR-08)** also involves the replacement of a number of minor distribution lines components, including failed sentinel lights. This specific investment replaces all failed sentinel lights with LED fixtures, whose longer service life is expected to eliminate the need for frequent bulb replacements and other sentinel light maintenance activities. Replacing sentinel lights with LED fixtures will reduce maintenance costs and this reduction has been included in Hydro One's proposed Sustaining OM&A expense plan for 2023.

3. **System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01)** include funding the addition of new overhead and underground circuit kilometres. While the addition of underground and overhead feeders would be expected to increase line maintenance costs, the change in the overall equipment population is not material and is therefore not expected to significantly impact planned expenditures for line maintenance.

4. **Distribution Lines Sustainment Initiatives (DSP Section 3.11, D-SR-10)** fund the rebuilding of line sections that are in poor condition. In cases where the line section is off-road, the line may be relocated to road allowance, which provides easier access for future corrective maintenance activities. The number of corrective maintenance activities is also expected to be reduced for newly build line sections. While corrective maintenance costs are anticipated to be lower for newly build line sections, less than one percent of the system will be rebuilt over the plan period. Thus, the overall equipment population condition is not sufficiently impacted by this investment to make a material difference on system maintenance costs.

3.8.3.2.5 PCB EQUIPMENT AND WASTE STORAGE

PCB Equipment and Waste Storage represents $9.4M of the overall Distribution Sustainment Lines OM&A forecast expenditures in 2023. These expenditures are a non-discretionary requirement and are needed to identify equipment that must be replaced to maintain compliance with the Federal PCB regulation (SOR/2008-273). Distribution Lines PCB Equipment Replacement Program (DSP Section 3.11, D-SR-06), funds the replacement of oil filled distribution lines equipment that exceed federal regulatory thresholds for PCB. This capital investment is expected to have no impact on PCB Equipment and Waste Storage OM&A costs, since the OM&A costs to identify PCB content determine which equipment is to be replaced under the capital program.

3.8.3.2.6 OTHER SERVICES

Other Services represents $15.6M of the overall Distribution Sustainment Lines OM&A forecast expenditures in 2023, which includes activities such as investigations and data collection, and transmission idle lines rental. Investigations and data collection do not have any correlation to capital expenditures. Where Hydro One Distribution is renting idle transmission lines to serve a distribution purpose, Hydro One Distribution must fund the investment needed to vacate those lines when required due to poor asset condition or transmission system needs. For the 2023-2027 period, one such relocation investment is planned under Distribution Lines Sustainment Initiatives (DSP Section 3.11, D-SR-10). The idle line section that will be vacated will result in a very small decrease of rental fees paid by Hydro One Distribution to Hydro One Transmission. Therefore, capital expenditures will minimally decrease Other Services OM&A after this investment is completed in 2024.

3.8.3.3 METERS, TELECOM, AND CONTROL

These OM&A expenditures, forecast to be $19.8M in 2023, fund the work required to inspect, repair or maintain revenue meters, and protection and control equipment. These forecast costs are higher than historical costs primarily due to the aging of Hydro One’s AMI 1.0 meter fleet, which is expected to have increased failure rates and will require increased sample testing given older meters require sample testing at a greater frequency than new meters. Meters, Telecom, and Control OM&A consists of the following activities:

3.8.3.3.1 REVENUE METERS

Retail Revenue Meters ($12.2M) and Wholesale Revenue Meters ($2.4M) comprise the bulk of forecast expenditures in this category. Retail meters, which are used for standard residential services, are required to be operated, maintained, and verified as mandated by Measurement

Canada regulations. These regulations require that testing be performed with increasing frequency as meters age. As the existing fleet of AMI 1.0 meters reaches the end of their service life, Hydro One also anticipates an increase in OM&A expenditures related to field work when these meters fail. The capital investments that could influence these OM&A metering expenditures are as follows:

1. **Advanced Meter Infrastructure 2.0 (DSP Section 3.11, D-SR-12)** represents the necessary expenditures to replace Hydro One's legacy AMI 1.0 system as it has reached end of its service life. These expenditures are expected to have a downward pressure on OM&A costs related to meter sample testing since new meters begin with the maximum Measurement Canada sampling period of ten years. This will not materially impact these OM&A costs until 2025, when AMI 2.0 deployment accelerates. Similarly, AMI 2.0 expenditures are also expected to have a downward pressure on OM&A costs related to field work associated with failing AMI 1.0 meters as the new meters will have significantly lower failure rates. This will not materially impact these OM&A costs until 2025 when AMI 2.0 deployment accelerates.

Once fully deployed in 2029, the AMI 2.0 program is expected to result in approximately $6.3M in annual OM&A savings from reduced manual meter reading (through improvements in network reach and reliability); reduced network costs (through a reduction in telecom circuits associated with a reduction in the number of regional collectors); reduced IT management costs (through the reduction in the number of Head End Systems), and reduced field visits (associated with remote disconnect/reconnect capability).

3.8.3.3.2 TELECOM, MONITORING, PROTECTION, AND CONTROL

Telecom, Monitoring, Protection and Control ($5.2M) represents the necessary expenditures to support, maintain, and troubleshoot communications for retail revenue metering, feeder sectionalizing switches, and distribution protection. The planned capital investments increasing the number of sectionalizing devices will put upward pressure on expenditures in this category as described below:

1. **Worst Performing Feeders (DSP Section 3.11, D-SS-05)** addresses reliability issues on Hydro One Distribution's worst performing feeders through the addition of SCADA-enabled sectionalizing switches. Since SCADA-enabled switches make use of battery power when the grid supply is lost, as Hydro One continues to deploy these switches on the distribution system, the associated OM&A costs related to planned battery replacements is anticipated to increase.

3.8.3.4 VEGETATION MANAGEMENT

These OM&A expenditures, forecast to be $139.4M in 2023, fund the work required to keep assets clear of vegetation such as adjacent trees and brush growth below lines. These expenditures are independent of distribution line equipment age or condition, thus any planned capital investments that impact the condition or age of existing assets will not impact vegetation management OM&A costs. Vegetation management expenditures are directly correlated with the number of kilometers of line section that need to be maintained. In addition, on-road line sections are generally cheaper to maintain than off-road line sections. Capital investments to relocate lines will decrease vegetation OM&A expenditures by moving off-road line sections to the road allowance, however, this will be offset by an increase in expenditures needed to maintain new line sections built to meet load growth. The result is that planned capital investments will not materially impact expenditures in this category. Further details are provided below.

1. **Distribution Lines Sustainment Initiatives (DSP Section 3.11, D-SR-10)** fund the rebuilding of line sections that are in poor condition. In cases where the line section exists off-road and is relocated to road allowance, this will result in easier access and can reduce vegetation management maintenance costs. Since less than one percent of distribution system kilometers of line will be impacted over the plan period, it is anticipated to result in a minimal decrease in vegetation OM&A expenditures.

2. **System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01)**, fund the addition of new overhead and underground circuits. In cases where new overhead lines are built, vegetation management costs will increase to maintain clearances to vegetation on the new lines. Since this investment is expected to increase total distribution system lines by less than one percent over the plan period, it is anticipated to result in a minimal increase in vegetation OM&A expenditures.

The following attachment(s) are provided as part of this section:

- Attachment 1 - Appendix A: OEB Appendix 2-AB

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

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2018			2019			2020			2021			2022			2023	2024	2025	2026	2027
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Fcst	Var	Plan	Fcst[2]	Var					
			%			%			%			%			%					
System Access	175.1	175.1	0%	147.9	197.3	33%	153.4	193.6	26%	150.9	171.5	14%	143.0	180.8	26%	239.6	240.6	227.0	212.6	204.3
System Renewal	219.7	219.7	0%	202.3	189.0	-7%	222.2	228.6	3%	237.3	236.1	-1%	256.7	224.9	-12%	373.1	410.3	494.2	491.5	497.8
System Service	79.1	79.1	0%	124.0	112.8	-9%	129.4	98.1	-24%	144.1	132.6	-8%	103.0	153.2	49%	196.5	169.7	229.6	192.0	205.9
General Plant	90.7	90.7	0%	142.8	114.3	-20%	150.3	178.2	19%	95.3	173.8	82%	100.4	105.7	5%	195.9	207.4	170.1	175.5	162.9
TOTAL EXPENDITURE	564.5	564.5	0%	617.1	613.4	-1%	655.3	698.6	7%	627.6	714.0	14%	603.2	664.6	10%	1,005.1	1,028.0	1,120.8	1,071.7	1,070.9
System OM&A	$ 544.4	$ 558.8	3%		$ 559.6	--		$ 560.2	--	--	$ 531.4	--	--	$ 535.8	--	$ 597.5	*	*	*	*

* System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2024 - 2027 is determined based on the escalation factor identified in Exhibit A-04-3.

** 2022 is Bridge Year Forecast

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
For a more detailed explanation of shifts in forecast vs historical expenditures, please see DSP Section 3.9
Notes on year over year Plan vs. Actual variances for Total Expenditures
See DSP Section 3.9 Appendix B "Capital Program Performance Report 2019, 2020"
Notes on Plan vs. Actual variance trends for individual expenditure categories
See DSP Section 3.9 Appendix B "Capital Program Performance Report 2019, 2020"

SECTION 3.9 – DSP – CAPITAL EXPENDITURES – TRENDS AND VARIANCES

3.9.1 INTRODUCTION

From 2023 to 2027, Hydro One Distribution plans to invest $5,297M in total capital expenditures across all four OEB categories (System Access, System Renewal, System Service, and General Plant), to balance various needs and priorities. Hydro One will also continue to invest where mandated by regulatory requirements to maintain compliance. Investments related to General Plant are detailed separately within the GSP Section 4.9. The trend over the test years of expenditures for System Access, System Renewal are System Service are summarized below:

- *System Access* – Capital expenditures over the test years are forecast to increase compared to historical levels as Hydro One continues to make non-discretionary investments to remain compliant with applicable codes, standards, laws, or regulations.
- *System Renewal* – Capital expenditures increase compared to historical levels to address deteriorating assets on the distribution system. These investments are critical to address assets in poor condition to maintain of overall system health. Failure to address these assets will result in increased pressure on future budgets, work execution capacity, and increase the risk to future reliability.
- *System Service* – Capital expenditures increase compared to historical levels as a result of modifications to Hydro One's distribution system to ensure that the system continues to meet operational objectives while addressing anticipated future customer electricity service requirements. Investments in this category are driven by reliability-focused initiatives, or in response to capacity or operational constraints caused by increased customer load.

For each category of System Access, System Renewal and System Service, this section first discusses variances between the OEB approved 2018-2022 capital levels versus 2018-2021 historical period actuals and the 2022 bridge year forecast. Hydro One has made every effort to manage capital expenditures to the overall envelope. As a result of increases in non-discretionary System Access expenditures, Hydro One was required to make reductions or deferrals to discretionary investments to mitigate the impact to the total capital envelope. As noted in Hydro One's Distribution Capital Performance Report, DSP Section 3.9, Attachment 2, Hydro One's total envelope-level variances to OEB-Approved capital amounts for 2019 and 2020 were -1% and +7% respectively.[1] This trend of non-discretionary expenditures impacting the pacing of discretionary investments is forecast to continue in 2021 and 2022.

Following the discussion of historical trends and variances, section 3 below discusses the trends of planned expenditures (2023-2027) relative to historic actuals for System Access, System Renewal and System Service. The largest increases in forecast investments are associated with Hydro One's plans to adequately address poor condition assets. Hydro One intends to maintain system reliability by replacing assets that pose higher reliability risks, including specific poles, line sections, and distribution stations, as well as renewing the company's smart meter fleet.

In addition to addressing the needs driven by asset condition under the System Renewal category, Hydro One's capital plan also proposes increases to discretionary investments under the System Service category, to facilitate load growth, improve reliability for vulnerable customers through energy storage solutions, and improve overall system reliability through grid modernization investments.

Figure 1 below shows the five-year view of Historical Period (2018-2021), Bridge Year (2022) and Forecasting Period (2023-2027).

[1] Including the General Plant capital allocated to distribution.

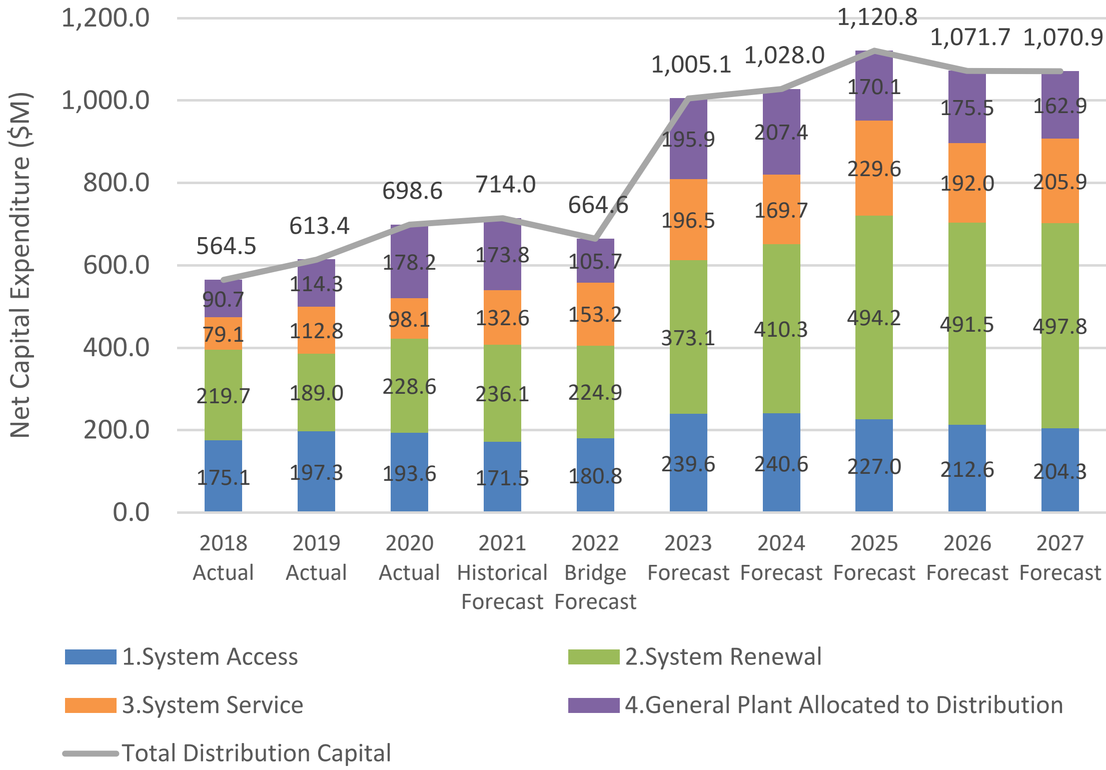

Figure 1: Historical and Forecast Capital Expenditures

3.9.2 HISTORICAL CAPITAL EXPENDITURES TRENDS AND VARIANCES

This section discusses Hydro One Distribution's historical actual capital expenditures and bridge year forecast in comparison to the levels approved during Hydro One's last distribution rate proceeding. For the 2018-2022 period, actual / forecast expenditures total $3,255M, which is 6% higher than the OEB-approved envelope of $3,068M.[2] Therefore Hydro One Distribution expects to exceed the multi-year OEB approved capital envelope by $187M. This overage is to accommodate increased non-discretionary System Access investments, stations demand capital program investments, trouble call and storm response activities, and to prioritize IT projects that have a significant benefit to the functionality of Hydro One Distribution's core business.[3] Further, additional investments were undertaken to address unprecedented and rapid growth in the Leamington-area, with cumulative customer requests related to the greenhouse sector in excess of 1,400 MW to date.

The above overages have been partially mitigated by an overall reduction in System Renewal and deferral of projects within System Service relative to the OEB-Approved amounts for the 2018-2022 period. When considering the overall system and customer needs, further deferrals were determined not to be prudent. Annual expenditures across all OEB categories are summarized in Table 1 below. The historical trends and variances of the System Access, System Renewal, and System Service categories are discussed in greater detail in the following sections. Since general plant expenditures are not specific to Hydro One Distribution, they are discussed separately in the GSP Section 4.9.

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[2] Including the General Plant investments allocated to Distribution.
[3] A notable IT project that is contributing to the overage is the Design Optimization and Transformation (DOT) project, which is an initiative to replace Hydro One Distribution's legacy design and estimating tool that, once complete, will ensure customer cost estimates are prepared in a shorter time, are more consistent, and cost less to develop. Additional details on variances that are specific to General Plant expenditures can be found in GSP Section 4.9.

Table 1 - Historical and Bridge Years Capital Expenditure Summary ($M)

OEB Category	Historical												Bridge Year		
	2018			2019			2020			2021			2022		
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
1.System Access	175.1	175.1	0%	147.9	197.3	33%	153.4	193.6	26%	150.9	171.5	14%	143.0	180.8	26%
2.System Renewal	219.7	219.7	0%	202.3	189.0	-7%	222.2	228.6	3%	237.3	236.1	-1%	256.7	224.9	-12%
3.System Service	79.1	79.1	0%	124.0	112.8	-9%	129.4	98.1	-24%	144.1	132.6	-8%	103.0	153.2	49%
Subtotal Categories 1, 2, and 3	**473.9**	**473.9**	**0%**	**474.2**	**499.1**	**5%**	**505.0**	**520.4**	**3%**	**532.3**	**540.2**	**1%**	**502.7**	**558.9**	**11%**
4.General Plant Allocated to Distribution	90.7	90.7	0%	142.8	114.3	-20%	150.3	178.2	19%	95.3	173.8	82%	100.4	105.7	5%
Total Distribution Capital	**564.5**	**564.5**	**0%**	**617.1**	**613.4**	**-1%**	**655.3**	**698.6**	**7%**	**627.6**	**714.0**	**14%**	**603.2**	**664.6**	**10%**
System OMA	**544.4**	**558.8**	**0.0**		**559.6**			**560.2**			**531.4**			**535.8**	

3.9.2.1 SYSTEM ACCESS

Table 2 - System Access

OEB Category	Historical												Bridge Year		
	2018			2019			2020			2021			2022		
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
1. System Access	175.1	175.1	0%	147.9	197.3	33%	153.4	193.6	26%	150.9	171.5	14%	143.0	180.8	26%

As discussed in exhibit DSP Section 3.6, System Access expenditures are non-discretionary investments that Hydro One is obligated to perform as a distributor to be compliant with applicable codes, standards, laws, or regulations. Hydro One's 2018 expenditures align exactly with forecast expenditures due to the timing of the OEB's Decision and Order in EB-2017-0049 (issued in March 2019), and as such are not generally included in the variance explanations.

As shown in Table 2, over the 2019 to 2022 period, System Access expenditures have been higher, and are forecast to remain higher, than OEB-approved levels. Expenditures have exceeded approvals primarily due to non-discretionary expenditures associated with the design and construction of new load customer connections and service upgrades (DSP Section 3.11, D-SA-02). These increased expenditures were driven by higher than forecast connection volumes and an increase in large expansion projects.

3.9.2.2 SYSTEM RENEWAL

Table 3 - System Renewal

OEB Category	Historical												Bridge Year		
	2018			2019			2020			2021			2022		
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
2. System Renewal	219.7	219.7	0%	202.3	189.0	-7%	222.2	228.6	3%	237.3	236.1	-1%	256.7	224.9	-12%

For the 2018-2022 period, System Renewal (Table 3) investments continue to represent the largest share of expenditures by category, however relative to the $1,138M total approved envelope, the $1,098M actual / forecast is $40M, or 4% lower. The reduction in System Renewal expenditures was, and will continue to be, due to the deferral of investments, which was required to accommodate increased System Access expenditures discussed above. Despite these deferrals, 51% of all System Renewal investments during this time are non-discretionary investments such as stations demand capital program, storm response, and PCB replacement, which are not candidates for deferral. The remaining investments are the only candidates for deferral in this category which are managed and paced by the investment planning process.

In addition to adjusting the pacing of planned investments to manage overall expenditures, Hydro One has also undertaken targeted initiatives to reduce capital expenditures while continuing to maintain the overall health of its asset base where possible. Examples of this approach are the wood pole test-and-treat and refurbishment programs, detailed within (DSP Section 3.11, D-SR-07). These programs extend wood pole life at a lower per pole cost than the cost of a complete replacement. A further example, related to distribution stations, is a newer padmount transformer design. Where implementation of this design is feasible, it results in a reduction of the overall infrastructure requirements, which reduces costs.

Despite the efforts Hydro One has made to reduce expenditures and maintain overall asset health, there is a significant population of deteriorating assets that have remained unaddressed and this is one of the factors resulting in an increase in System Renewal expenditures, as detailed further below.

3.9.2.3 SYSTEM SERVICE

Table 4 - System Service

OEB Category	Historical (Previous Plan and Actual / Forecast)												Bridge Year		
	2018			2019			2020			2021			2022		
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
3. System Service	79.1	79.1	0%	124.0	112.8	-9%	129.4	98.1	-24%	144.1	132.6	-8%	103.0	153.2	49%

System Service expenditures (Table 4) are anticipated to be closely aligned with the overall approved totals for the 2018-2022 period ($579M approved versus $576M actual). However, to accommodate needs in other categories, specifically, non-discretionary expenditures within the System Access category, there are year to year variations in System Service investments resulting from adjustments to the pacing of these investments that are discretionary in nature.

The list of load growth investments completed within the System Service category has changed from the last filing. The main driver of this change was the unanticipated investment needed in the Leamington area. Since the last application, the Leamington area has seen an influx of greenhouses. This recent growth has led to an unprecedented corresponding increase in customer requests for capacity, now in excess of 1,400 MW. To accommodate these connection requests Hydro One had to increase investments beyond the previously planned levels in the System Access category, as noted above in section 2.1. As a result of this and other funding needs, investments in planned system upgrades have been deferred from the 2018-2022 period into the 2023-2027 planning period as discussed below.

3.9.3 FORECAST CAPITAL EXPENDITURE TRENDS

This section discusses the trends between Hydro One Distribution's historical actual expenditures (2018-2022) and forecast expenditures (2023-2027). These expenditures are summarized in Table 5 below, and plotted in Figure 2 for a visual indication of expenditure trends and represent an increase of approximately 63% over the actual and forecast capital expenditures for the 2018-2022 period.

Table 5 - Ten-year Capital Plan ($M)

OEB Category	Historical				Bridge	Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1. System Access	175.1	197.3	193.6	171.5	180.8	239.6	240.6	227.0	212.6	204.3
2. System Renewal	219.7	189.0	228.6	236.1	224.9	373.1	410.3	494.2	491.5	497.8
3. System Service	79.1	112.8	98.1	132.6	153.2	196.5	169.7	229.6	192.0	205.9
Subtotal Categories 1, 2, and 3	**473.9**	**499.1**	**520.4**	**540.2**	**558.9**	**809.2**	**820.6**	**950.7**	**896.1**	**908.0**
4. General Plant Allocated to Distribution	90.7	114.3	178.2	173.8	105.7	195.9	207.4	170.1	175.5	162.9
Total Distribution Capital	**564.5**	**613.4**	**698.6**	**714.0**	**664.6**	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**
System OMA	**558.8**	**559.6**	**560.2**	**531.4**	**535.8**	**597.5**				

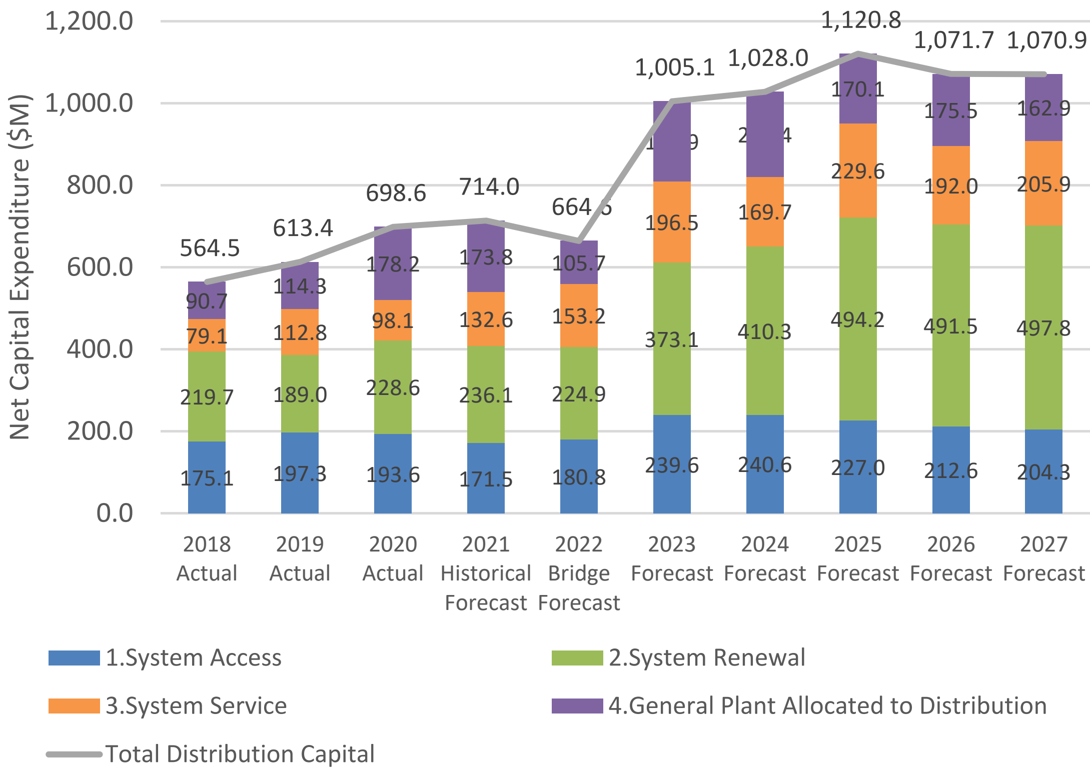

Figure 2: Ten-Year Capital Plan Snapshot

3.9.3.1 SYSTEM ACCESS

Table 6 - System Access ($M)

OEB Category	Historical				Bridge	Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1. System Access	175.1	197.3	193.6	171.5	180.8	239.6	240.6	227.0	212.6	204.3

Forecast expenditures for System Access (Table 6) throughout the 2023-2027 test years are higher than 2018-2022 actual / forecast expenditures. This increase is attributable to costs related to new and upgraded connections, metering sustainment, and joint use requests. System Access expenditures represent mandatory obligations for Hydro One Distribution. For example, the forecasted increase in metering sustainment costs in 2023 is a result of the increasing number of failing smart meters that must be addressed. These sustainment costs are forecast to gradually decrease beyond 2024, as planned meter replacement (System Renewal) programs increase within the same timeframe. A summary of the forecast increases within the System Access category are as follows:

1. New Load Connections, Upgrades, Cancellations (DSP Section 3.11, D-SA-02), total increase of $111.2M;
2. Metering Sustainment (DSP Section 3.11, D-SA-04), total increase of $87.6M, and
3. Joint Use and Relocations (DSP Section 3.11, D-SA-01), total increase of $18.6M.

A more detailed description of the most significant increases that are being forecasted for System Access investments are as follows:

1. New Load Connections, Upgrades, Cancellations (DSP Section 3.11, D-SA-02), represents total expenditures of $793.0M over the 2023-2027 planning period, which is an increase of $111.2M from actual / forecast expenditures for the 2018-2022 historical period. Expenditures for the design and construction of new and upgraded connections will increase approximately 10% throughout the planning period, which is a result of forecasted volumes.

2. Metering Sustainment (DSP Section 3.11, D-SA-04) represents total expenditures of $189.5M over the 2023-2027 planning period, which is an increase of $87.6M from actual / forecast expenditures for the 2018-2022 period. The forecast increase in metering sustainment is a result of meter failures, as an increasing number of meters reach the end of their service life. Metering sustainment costs will peak in 2023 at $62.6M, and steadily decline to $8.9M in 2027, as a result of the installation of new AMI 2.0 meters (DSP Section 3.11, D-SR-12). Metering sustainment expenditures support corrective and preventative maintenance programs to meet regulatory requirements under the *Electricity and Gas Inspection Act*, the Weights and Measures Act, the OEB's DSC, and the IESO's *Market Rules*. Retail revenue metering represents approximately 97% of the total expenditures and are required to meet regulatory requirements for meter sampling and for the replacement of failing AMI 1.0 meters that have begun to reach end-of-life. The remaining Wholesale Revenue Metering (WRMI) expenditures (approximately 3% of

total) are relatively consistent and address IESO market rule reporting requirements, meter reverification, corrective and preventative maintenance.

3. Joint Use and Relocations (DSP Section 3.11, D-SA-01) represents total expenditures of $134.6M over the 2023-2027 planning period, which is an increase of $18.6M from actual / forecast expenditures for the 2018-2022 historical period. Joint Use and Relocation expenditures for the 2023-2027 planning period are based on historical spending, and are adjusted to reflect forecast work volumes provided by Joint Use Partners, where available. External factors such as the planned expansion of telecommunications infrastructure, driven by some of our Joint Use partners, and internal factors such as the integrated work volumes of acquired utilities are reflected in the anticipated increase of forecast work volumes as compared to the historical period. Year-over-year variations in expenditures are generally due to the expected volume and scope of Joint Use and Relocation requests.

3.9.3.2 SYSTEM RENEWAL

Table 7 - System Renewal ($M)

OEB Category	Historical				Bridge	Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
2. System Renewal	219.7	189.0	228.6	236.1	224.9	373.1	410.3	494.2	491.5	497.8

For the 2023-2027 planning period, System Renewal (Table 7) represents the greatest share of capital expenditures, and is forecast to increase funding requirements from the historical and bridge years. The bulk of these increases over the 2023-2027 planning period are attributed to expenditures for:

1. Advanced Meter Infrastructure 2.0 (DSP Section 3.11, D-SR-12), total increase of $553.8M;
2. Pole Sustainment Program (DSP Section 3.11, D-SR-07), total increase of $289.2M;
3. Distribution Station Refurbishment (DSP Section 3.11, D-SR-04), total increase of $133.4M;
4. Distribution Lines Sustainment Initiatives (DSP Section 3.11, D-SR-10), total increase of $131.1M; and

5. Distribution Lines Trouble Call and Storm Damage Response (DSP Section 3.11, D-SR-05), total increase of $21.4M.[4]

Each variance is discussed below, with additional investment-specific details found within each ISD:

1. The Advanced Metering Infrastructure 2.0 program (DSP Section 3.11, D-SR-12), represents total expenditures of $558.3M over the 2023-2027 planning period, which is an increase of $553.8M from actual / forecast expenditures for the 2018-2022 period.[5] The AMI 2.0 program constitutes the planned investments needed to mass replace Hydro One's legacy AMI 1.0 system. Since this is a new program, the expenditure increases are closely aligned to expenditure totals. The AMI 1.0 system is comprised of approximately 1.4 million smart meters, of which close to 1 million are between 11-13 years old and will soon reach the end of their service life. Manufacturer service life attestations, benchmarking studies, independently conducted Accelerated Life Testing (ALT) of meters, and trends in increasing meter failures all support an approximately 15-year service life for AMI 1.0 meters. Significantly, the ALT study found critical failures in meters involving the rapid degradation of the capacitor that enables meters to reliably communicate, and based on these findings, close to 579,000 meters are projected to fail by the end of the planning period in 2027. The physical deterioration of meter components and meter failures create impacts and critical risks for Hydro One affecting various elements of its business including:
    - Increased meter sustainment costs associated with the need to individually replace increasing numbers of failed AMI 1.0 meters (see SA-04);
    - Higher labour costs for unplanned individual failed meter replacement relative to more efficient planned mass meter replacement;

[4] $17.8M in 2018 and $20.7M in 2019 of historical actual expenditures that are captured under DSP Section 3.11, D-SR-05 were previously captured under the System Service category and are categorized as SS-Other in Appendix 2-AA: Capital Projects Table.
[5] As noted in DSP Section 3.11, D-SR-12, Hydro One had prior investments of approximately $4M for the Head End System and the Pilot Project.

- Reduced billing reliability and resultant customer dissatisfaction from estimated billing and billing corrections;
- Replacement of failed meters with obsolete technology and associated lost opportunities for future benefits associated with a modern system; and
- Regulatory non-compliance.

Additional details on the rationale, timing, and scope of the AMI 2.0 program investment can be found in DSP Section 3.2, as well as DSP Section 3.11, D-SR-12.

2. The pole sustainment program (DSP Section 3.11, D-SR-07) represents total expenditures of $562.6M over the 2023-2027 planning period, which is an increase of $289.2M from actual / forecast expenditures for the 2018-2022 historical period. The forecast increases are due to proposed increased work volumes as detailed in DSP Section 3.11, D-SR-07, which is required to reduce the total number of poor condition poles. Increased costs are also a result of Hydro One's targeted approach to pole replacements that focus on the poles that pose the greatest reliability risk. Poles that pose the greatest reliability risk are those that are poor condition and support multiple circuits or serve higher numbers of downstream customers. Replacing poles that support multiple circuits have higher costs for both labour and materials, resulting in increased unit values. Accordingly, Hydro One continues to focus on pole condition and reliability impact as the primary drivers for investment, and is planning to replace 51,500 poles and refurbish another 14,000 as part of the 2023-2027 pole sustainment program.
3. The Distribution Station Refurbishment program (DSP Section 3.11, D-SR-04), represents total expenditures of $179.1M over the 2023-2027 planning period, which is an increase of $133.4M from actual / forecast expenditures for the 2018-2022 historical period. The forecast increase is due to the need to replace transformers identified in to be in poor condition to maintain the health of the transformer population and mitigate the risk of long duration outages. Of the 992 Distribution Stations that Hydro One owns, maintains, and operates, approximately 20% or 237 have power transformers classified as being in "poor condition" and at high risk of failure. A power transformer failure is a significant reliability event for the customers supplied by the station, with restoration efforts that take 6.6 hours on average for a Mobile Unit Substation (MUS) to be brought to site. In

severe cases, these outages can take up to 21 hours. Station refurbishments aim to replace station transformers that are in poor condition, and avoid the lengthy outages associated with a failure. Although station refurbishment expenditures are forecast to increase, the forecasted expenditure level is the amount required to fund the replacements necessary to prevent a rise in the current percentage of transformers in poor condition (i.e., 20%).

4. The Distribution Lines Sustainment Initiatives program (DSP Section 3.11, D-SR-10), represents total expenditures of $183.0M over the 2023-2027 planning period, which is an increase of $131.1M from actual / forecast expenditures for the 2018-2022 historical period. The proposed increase in Distribution Lines Sustainment expenditures is due to two main reasons. First, the deferral of previously planned overhead feeder investments from the 2018-2022 period to accommodate non-discretionary investments. Second, to fund a new cable injection investment to rejuvenate specific sections of underground cable that are at risk of failing, which is a lower-cost alternative to a traditional capital replacement. These increased expenditures for lines sustainment initiatives are crucial to prevent asset failure and the associated reliability impacts.

5. Distribution Lines Trouble Calls and Storm Damage Response (D-SR-05), represents total expenditures of $551.7M over the 2023-2027 planning period, which is an increase of $21.4M from actual / forecast expenditures for the 2018-2022 historical period. These expenditures comprise the non-discretionary work required to restore supply for Hydro One customers or address imminent safety hazards. Hydro One’s forecasting for storm response expenditures is based on an inflation-adjusted average of annual expenditures since 2005, with “outlier” years of unusually high expenditures removed from the forecast – namely, 2006, 2013, and 2018.

3.9.3.3 SYSTEM SERVICE

Table 8 - System Service ($M)

OEB Category	Historical				Bridge	Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
3. System Service	79.1	112.8	98.1	132.6	153.2	196.5	169.7	229.6	192.0	205.9

Over the planning period, Hydro One plans to increase System Service (Table 8) investments in several areas. These investments are comprised of investments that address load growth, and those that address reliability. Load growth investments facilitate continued customer connections in areas where capacity is limited, whereas reliability investments improve the continuity of supply, particularly for customers who experience especially poor reliability. A summary of the forecast increases within the System Service category are as follows:

1. Energy Storage Solutions (DSP Section 3.11, D-SS-04), total increase of $162.6M;
2. System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01), total increase of $150.4M;
3. Worst Performing Feeders (DSP Section 3.11, D-SS-05), total increase of $119.5M;
4. Reliability Improvements (DSP Section 3.11, D-SS-02), total increase of $22.1M; and
5. Demand System Modifications (DSP Section 3.11, D-SS-03), total increase of $16.2M

A more detailed summary of all System Service investments, including the forecast expenditures and increases relative to historical actuals, is as follows:

1. Energy Storage Solutions (DSP Section 3.11, D-SS-04), represents total expenditures of $177.3M over the 2023-2027 planning period, which is an increase of $162.6M from actual / forecast expenditures for the 2018-2022 historical period. Since this is a new initiative, the expenditure increase is closely aligned with expenditure totals. Energy storage investments will address customers and communities with exceptionally poor reliability, whose reliability performance cannot be economically addressed through other more conventional alternatives, such as building a redundant supply point. Energy storage solutions introduce system resilience directly at the customer site, by providing a temporary source of backup power when the upstream supply is lost. These energy storage expenditures are being undertaken in alignment with customer engagement

results which support addressing customers with exceptionally poor reliability by leveraging energy storage technologies.

2. System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01), represents total expenditures of $478.2M over the 2023-2027 planning period, which is an increase of $150.4M from actual / forecast expenditures for the 2018-2022 historical period. Load growth investments are critical to ensuring Hydro One's system has sufficient capacity to accommodate new connections, and to support growing communities. Not performing these investments will lead to an increased risk of asset failure and / or power quality issues. The trend of increased expenditures throughout the 2023-2027 planning period is in part due to project deferrals from the 2018-2022 period, as well as ongoing costs associated with greenhouse growth in the Windsor-Essex (Leamington) area, which total approximately $200M for the 2018-2022 period, and approximately $170M for the 2023-2027 planning period.
3. Worst performing feeders (DSP Section 3.11, D-SS-05), represents total expenditures of $209.4M over the 2023-2027 planning period, which is an increase of $119.5M from actual / forecast expenditures for the 2018-2022 historical period. The continuation of Hydro One's worst performing feeders program aims to address feeders that are performance outliers, and which contribute the most to system SAIDI. Funding for the worst performing feeders program is planned to increase in 2023, with expenditures remaining consistent throughout the planning period. These increased expenditures are in response to customer engagement results, which indicated strong support to increase the pace of reliability improvements through grid modernization. Customers also identified a reliable electrical supply as one of their top outcome priorities.
4. Reliability Investments (DSP Section 3.11, D-SS-02) represents total expenditures of $40.0M over the 2023-2027 planning period, which is an increase of $22.1M from actual / forecast expenditures for the 2018-2022 historical period. These investments target feeders where reliability improvements can be achieved by creating ties between feeders and utilizing SCADA controls to remotely operate feeder ties. SCADA-enabled feeder ties will minimize the extent of an outage through an alternate supply point, and can be achieved in much less time than manual, on-site, restoration efforts.

5. Demand System Modifications (DSP Section 3.11, D-SS-03), represents total expenditures of $68.3M over the 2023-2027 planning period, which is an increase of $16.2M from actual / forecast expenditures for the 2018-2022 historical period, and is based on historical trends. Demand system modifications address near-term system needs that arise from naturally occurring changes to the distribution system, which are usually caused by localized load growth. These non-discretionary investments are critical to ensure the continued performance of Hydro One's distribution system and to comply with the section 3.3 of the DSC.

The following attachment(s) are provided as part of this section:

- Attachment 1 – Dx Chapter 2 Appendix 2-AA - Capital Projects Table for Distribution
- Attachment 2 – Capital Program Performance Report 2019 to 2020

Appendix 2-AA
Capital Projects Table ($M)

Projects	2018	2019	2020	2021 Bridge	2022 Bridge	2023 Test	2024 Test	2025 Test	2026 Test	2027 Test
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
System Access										
D-SA-01 Joint Use and Relocations	20.4	28.8	26.2	21.4	19.1	24.8	29.0	27.0	26.5	27.2
D-SA-02 New Load Connections, Upgrades, Cancellations	121.2	141.7	146.4	130.6	141.7	150.7	154.6	158.5	162.5	166.7
D-SA-03 Customer Demand Distributed Energy Resources	6.7	6.6	2.2	1.9	1.4	1.4	1.4	1.4	1.4	1.4
D-SA-04 Metering Sustainment	26.8	20.1	18.8	17.6	18.5	62.6	55.6	40.1	22.2	8.9
D-SA-Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	**175.1**	**197.3**	**193.6**	**171.5**	**180.8**	**239.6**	**240.6**	**227.0**	**212.6**	**204.3**
System Renewal										
D-SR-01 Distribution Stations Demand Capital Program	6.6	5.6	9.8	4.9	5.0	6.2	6.3	6.4	6.5	6.7
D-SR-02 Mobile Unit Substation Program	1.3	6.9	4.0	4.2	4.3	3.5	4.2	2.9	3.3	4.6
D-SR-03 Distribution Station Planned Component Replacement Program	5.0	7.7	8.8	6.9	7.1	4.6	3.3	1.1	1.2	1.2
D-SR-04 Distribution Station Refurbishment	11.7	16.5	7.4	6.9	3.2	44.8	41.5	28.5	32.3	32.1
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response	112.7	74.6	118.4	92.3	93.8	106.0	108.1	110.3	112.5	114.7
D-SR-06 Distribution Lines PCB Equipment Replacement Program	6.3	8.1	4.8	9.5	9.5	9.4	9.5	9.5	0.0	0.0
D-SR-07 Pole Sustainment Program	52.0	44.3	43.6	73.4	60.1	107.9	110.6	112.4	114.9	116.8
D-SR-08 Distribution Lines Minor Component Replacement Program	1.4	4.9	6.3	12.4	12.3	12.4	14.5	13.5	8.6	7.1
D-SR-09 Submarine Cable Replacement Program	3.2	6.3	6.7	10.9	11.1	12.2	12.5	12.7	13.0	13.2
D-SR-10 Distribution Lines Sustainment Initiatives	7.8	8.1	11.7	10.7	13.7	31.5	30.3	35.3	43.2	42.7
D-SR-11 Life Cycle Optimization & Operational Efficiency Projects	9.1	3.9	6.2	2.5	0.2	2.8	6.5	7.1	0.8	0.4
D-SR-12 Advanced Meter Infrastructure 2.0 (AMI 2.0)	0.0	0.0	0.0	0.7	3.9	30.9	62.0	153.7	154.4	157.3
D-SR-Other	2.6	2.0	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9
Sub-Total	**219.7**	**189.0**	**228.6**	**236.1**	**224.9**	**373.1**	**410.3**	**494.2**	**491.5**	**497.8**
System Service										
D-SS-01 System Upgrades Driven by Load Growth	26.5	45.2	50.7	97.1	108.5	98.2	76.3	127.5	76.1	100.2
D-SS-02 Reliability Improvements	1.7	4.1	4.6	3.8	3.7	7.3	0.1	6.5	18.6	7.5
D-SS-03 Demand System Modifications	7.9	11.8	14.0	7.5	10.9	13.2	13.4	13.7	13.9	14.2
D-SS-04 Energy Storage Solutions	0.1	1.6	5.0	3.7	4.2	34.3	35.0	35.6	36.3	36.0
D-SS-05 Worst Performing Feeders	8.3	21.9	20.7	17.0	22.0	39.6	40.9	42.2	43.0	43.8
D-SS-06 Power Quality and Stray Voltage	1.0	1.3	1.2	3.3	3.4	3.8	3.9	4.0	4.0	4.1
D-SS-Other	33.6	26.9	2.0	0.1	0.4	0.1	0.1	0.1	0.1	0.1
Sub-Total	**79.1**	**112.8**	**98.1**	**132.6**	**153.2**	**196.5**	**169.7**	**229.6**	**192.0**	**205.9**
General Plant Allocated to Distribution										
Fleet	18.1	29.0	25.7	28.3	28.5	50.6	51.7	52.2	53.0	54.7
Facilities & Real Estate	13.7	15.6	45.0	23.7	26.5	65.4	67.2	44.2	39.9	35.7
Information Solutions	52.3	67.4	76.2	66.1	44.0	62.5	71.6	68.5	78.5	70.2
System Operations	5.3	4.7	32.8	55.7	5.7	15.4	14.7	4.0	3.2	2.3
System Capability Reinforcement	2.9	-1.0	-0.7	0.0	1.0	2.0	2.2	1.1	1.0	0.0
Other	-1.7	-1.5	-0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	**90.7**	**114.3**	**178.2**	**173.8**	**105.7**	**195.9**	**207.4**	**170.1**	**175.5**	162.9
Total	**564.5**	**613.4**	**698.6**	**714.0**	**664.6**	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***										
Total	**564.5**	**613.4**	**698.6**	**714.0**	**664.6**	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

CAPITAL PROGRAM PERFORMANCE REPORT 2019 AND 2020

1.0 INTRODUCTION

This distribution Capital Program Performance Report is provided in response to the Ontario Energy Board's (OEB) Decision and Order in EB-2017-0049, which directed Hydro One to submit with this application a comprehensive report detailing the Company's actual performance in the execution of its capital program relative to plan.[1]

In particular, the OEB directed that this report:

- Show performance at the program level in terms of overall expenditures and in-service additions relative to plan. This information is provided in section 2.0, at the OEB category level.
- Show the status of each major project or program (i.e., those with a total budgeted cost greater than $3M and planned to be completed during the test years) and provide an explanation of variance regarding scope, cost or schedule. Program-level variances are provided in section 3.0. Major project variances are provided in section 3.2.

This report is divided into two main sections. Section 2.0 focuses on performance at the overall envelope and OEB category level, demonstrating Hydro One's ability to successfully manage to the overall capital envelope in terms of both capital expenditures and ISAs. Section 3.0 focuses on performance at the project and program level. That section outlines the approach used by Hydro One to manage projects and programs and provides an overview of performance. The projects and programs included in this report have material (greater than or equal to $3 million) actual or planned ISA in 2019 and 2020.

[1] EB-2017-0049, Decision and Order, March 7, 2019, Appendix 2. The TSP and GSP Capital Program Performance Reports are filed in this application as DSP Section 2.9, Attachment 2 and GSP Section 4.9, Attachment 2 respectively.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL

Hydro One's Distribution capital portfolio is comprised of investments designed to refurbish existing assets as well as install new assets to address system needs. The Distribution capital envelope is predominantly program-based with smaller scale projects. Distribution is also required to respond to a high volume of demand work with short turnaround times, which can impact work completed within the capital envelope annually.

A summary of the Distribution capital envelope for 2019 and 2020 is shown below in Table 1, organized according to the categories defined by the OEB Filing Requirements.

Table 1 - Distribution Capital Expenditures and In-Service Additions (2019 and 2020) (M)[2]

OEB Category	Capital Expenditures 2019			In-Service Additions 2019			Capital Expenditures 2020			In-Service Additions 2020		
	Plan	Actuals	Variance	Plan	Actuals	Variance	Plan	Actuals	Variance	Plan	Actuals	Variance
1. System Access	147.9	197.3	**33%**	147.7	189.9	**29%**	153.4	193.6	**26%**	144.7	197.5	**36%**
2. System Renewal	202.3	189.0	**-7%**	223.3	201.9	**-10%**	222.2	228.6	**3%**	225.3	217.8	**-3%**
3. System Service	124.0	112.8	**-9%**	81.6	89.2	**9%**	129.4	98.1	**-24%**	170.9	97.3	**-43%**
Subtotal Categories 1, 2, and 3	**474.2**	**499.1**	**5%**	**452.6**	**481.1**	**6%**	**505.0**	**520.4**	**3%**	**540.9**	**512.6**	**-5%**
4. General Plant Allocated to Distribution	142.8	114.3	**-20%**	103.9	104.1	**0%**	150.3	178.2	**19%**	135.9	155.5	**14%**
Grand Total	**617.1**	**613.4**	**-1%**	**556.5**	**585.1**	**5%**	**655.3**	**698.6**	**7%**	**676.8**	**668.1**	**-1%**

At the total envelope level for 2019, including General Plant Allocated to Distribution, capital expenditures totalled $613.4M, which is 1% lower than the approved enveloped, while in-service additions totalled $585.1M or 5% higher than the approved envelope. For 2020, total envelope capital expenditures totalled $698.6M or 7% higher than the approved envelope and in-service additions totalled $668.1M or 1% lower than the approved envelope. Details on the capital and in-service additions for General Plant Allocated to Distribution are provided in the Capital Program Performance Report for General Plant in DSP Section 4.9, Attachment 2. The

[2] Does not include Acquired Utilities of Haldimand, Norfolk, and Woodstock.

remainder of this report focuses on the capital and in-service performance of System Access, System Renewal, and System Service investments attributable wholly to Distribution.

In 2019, Distribution's capital expenditures totalled $499M, which represents an overage of 5% compared to the approved envelope and 6% variance for in-service additions. Capital expenditures in 2020 totalled $520M which represents an overage of 3%, while in-service additions were 5% lower than plan at $513M. This trend was largely due to overspending within the System Access category which contains non-discretionary investments partially offset by reductions in System Renewal and System Service. Although the nature of some work performed under System Renewal and System Service categories provide more flexibility around timing of completion compared to System Access, there are circumstances where the impact to the system poses a high-risk failure and consequence which drives the need for increased capital expenditure. Details on the drivers of variances in each year are provided in sections 2.1 and 2.2 for 2019 and 2020, respectively.

As evident from Table 1, the pattern of heightened non-discretionary spending was generally offset by reprioritization of other important but ultimately discretionary work. This reflects Hydro One Distribution's active management of a large capital portfolio which includes large proportion of non-discretionary, externally-driven spending. Circumstances may change throughout the year and the organization must adapt accordingly. In many cases, Hydro One is required to meet legal, contractual or statutory obligations, and as such there are no alternatives other than to fund demand work as required. As a consequence, in-year fluctuations and re-direction occurs resulting in variances between planned and actual capital expenditures.

2.1 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL IN 2019

In 2019, at the overall envelope level, Distribution capital expenditures and in-service additions were higher than budget by $24.9M or 5%, and $28.5M or 6% respectively as shown in Table 2. The OEB categories and associated variance explanations are outlined below.

Table 2 - OEB Category Performance 2019 ($M)

OEB Category	Capital Expenditures			In-Service Additions		
	2019			2019		
	Plan	Actuals	Variance	Plan	Actuals	Variance
1.System Access	147.9	197.3	**33%**	147.7	189.9	**29%**
2.System Renewal	202.3	189.0	**-7%**	223.3	201.9	**-10%**
3.System Service	124.0	112.8	**-9%**	81.6	89.2	**9%**
Subtotal Categories 1, 2, and 3	**474.2**	**499.1**	**5%**	**452.6**	**481.1**	**6%**
4.General Plant Allocated to Distribution	142.8	114.3	**-20%**	103.9	104.1	**0%**
Grand Total	**617.1**	**613.4**	**-1%**	**556.5**	**585.1**	**5%**

System Access: The largest variance in 2019 was in the System Access category, with capital expenditures and in-service additions higher than budget by $49M or 33% and $42M or 29% respectively. The main driver of this overage compared to the approved expenditure amount was increased demand for more complex New Load Connections and Service Upgrades, specifically to support line expansion requests, subdivision connections and large customer upgrades.

System Renewal: Capital expenditures and in-service additions were lower than budget by $13M or 7% and $21M or 10% respectively, primarily due to the Pole Replacement program which accounted for nearly $9M of capital expenditure reductions. This was a direct result of funding reallocated and resources deployed to higher priority customer-driven demand work within System Access. Additional reductions to Pole Replacement to further offset the variance were not approved as it presented risk to the system based on the conditions of the poles identified for replacement and the organization did not want to introduce greater risk to the pole demographics in future years. The remaining reductions were made in the Distribution Lines Planned Component Replacement, Distribution Lines PCB Equipment Replacement and Submarine Cable Replacement programs and was a combination of lower replacement volumes required and resources and funding reallocated to higher demand volumes whereby replacement was deferred to future years.

System Service: Overall, capital expenditures were $11M or 9% lower than budget while in-service additions were $7M or 9% higher than budget, due to increases and decreases required among various investments in the category based on customer priorities, project deferrals, system needs and resource availability. As a result of increased expenditures in support of Leamington Feeder Development work and the Worst Performing Feeder Initiative, deferral of multiple major projects were used to offset these increases. Overall reductions were also offset by an increase of $9M required to fund Post Trouble work that was largely field initiated and deemed a risk if not addressed immediately.

2.2 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL IN 2020

In 2020, at the overall envelope level, Distribution capital expenditures were $15.4M or 3% higher than budget, while in-service additions were $28M or 5% lower than budget as shown in Table 3. The OEB categories and associated variance explanations are outlined below.

Table 3 - OEB Category Performance 2020 ($M)

OEB Category	Capital Expenditures			In-Service Additions		
	2020			2020		
	DRO Plan	Actuals	Variance	DRO Plan	Actuals	Variance
1. System Access	153.4	193.6	**26%**	144.7	197.5	**36%**
2. System Renewal	222.2	228.6	**3%**	225.3	217.8	**-3%**
3. System Service	129.4	98.1	**-24%**	170.9	97.3	**-43%**
Subtotal Categories 1, 2, and 3	**505.0**	**520.4**	**3%**	**540.9**	**512.6**	**-5%**
4. General Plant Allocated to Distribution	150.3	178.2	**19%**	135.9	155.5	**14%**
Grand Total	**655.3**	**698.6**	**7%**	**676.8**	**668.1**	**-1%**

System Access: The largest variance in 2020 was in the System Access category, with capital expenditures and in-service additions higher than budget by $40M or 26% and $53M or 36% respectively. The main driver of this overage compared to the approved expenditure amount was increased demand for large New Load Connections and Service Upgrade projects which also impacted costs associated with design and estimation due to project complexity and varying scope compared to historical requests. A significant portion of this work was within the Essex area where there has been an influx of greenhouses in recent years and a corresponding demand for large expansions and connections. In addition, increased demand within the Joint Use and Relocations program occurred to support an influx of requests for third party attachments primarily related to broadband internet access.

System Renewal: Capital expenditures were $6M or 3% higher than budget while in-service additions were $7.5M or 3% lower than budget. The increase in expenditures was largely a result of costs incurred within the Distribution Lines Trouble Call and Storm Damage Response program, totalling $25.4M. The primary offset to these increases, were reductions made were to the Pole Replacement program, which was decreased by $17.3M. Due to the nature of work that is required to maintain a safe and reliable Distribution network and the reduction made to the Pole Replacement program, there was limited flexibility for further reductions within this category.

System Service: The System Service capital expenditures and in-service additions were lower than budget by $31M or 24% and $73.6M or 43% respectively. This was primarily due to major projects being deferred to facilitate staying within or close to the OEB approved envelope. In addition, many load growth system upgrade projects originally planned were deferred to accommodate an increase in funding above approved levels needed support the Leamington DESN#2 Feeder Development Project, Nakina BESS Project, the Worst Performing Feeder Initiative and Post Trouble work.

3.0 PERFORMANCE AT THE PROGRAM AND PROJECT LEVEL

Hydro One's Distribution expenditures consist of programs and projects. Programs involve work that is repeatable in nature on a specific asset type that recurs every year and the assets are in-serviced in the same fiscal year. Projects are stand-alone jobs with a discrete beginning and end which may span over more than one fiscal year and in-service does not occur until energization occurs. Program-level variances are discussed in Section 3.1, and project-level variances are discussed in Section 3.2.

Programs and projects with a total budgeted cost of greater than $3M have been summarized in the following sub-sections along with variance explanations. The thresholds used by Hydro One to identify "material variances" were determined using the following criteria:

- **Scope Variances** – For programs, material scope variances arise if the unit accomplishment filed in the rate application varied from the actual unit accomplishment by 20%. For projects, material scope variances arise if the project required internal approval for a scope change.
- **Cost Variances** – Material cost variances were identified where the in-year variance in cost is greater than or equal to $0.5M and the cost is 10% over or under budget.
- **Date Variances** – Material date variances were identified where the actual or projected in-service year changed from the year proposed.

Capital programs and projects that met at least one of these criteria were deemed to be material variances for the purposes of this report. Material variances are presented in four categories:

- **Emergent Needs**: Emergent needs are investments that Hydro One made and in-serviced during the 2019-2020 period in response to a change of priority due to equipment condition or failure, as well as customer needs.
- **Reprioritization**: Reprioritization includes investments that are accelerated or deferred. Accelerated investments can include projects or programs that need to be completed sooner than planned and follow Hydro One's redirection process. The process allows the company to adjust its work delivery when changes occur. In some cases, this results in the acceleration of work when resources are redirected from another delayed project. Alternatively, deferral can occur as a result of increased demand for non-discretionary investments and planned discretionary work is reprioritized as a result.
- **Execution Factors**: Execution factors represent delays encountered during the execution phase of work which can include timing delays that arise as a result of changing conditions, risks and priorities that need to be addressed during execution. As risks materialize, plans are adjusted to accommodate the change and mitigate the overall

impact to cost, schedule and resources. This can change the year in which the project goes in-service but does not typically change the in- service amount or have impacts to the volume of work completed within a capital program and subsequently can impact in-service additions. Some of the main causes for delays are outage delays or cancellations, material delivery and logistics factors as well as customer needs.

- **Work Definition Issues**: Work definition variances naturally arise as a project's scope, estimated budget and schedule are refined and the project moves from the high-level planning phase to design and estimate followed by execution. As the project is refined, there may be increases or decreases to the project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

As is described in the Distribution Capital Work Execution Strategy (DSP Section 3.10), Hydro One Distribution continues to improve its planning and estimating processes, tools and technology to minimize work definition issues. As a result, the in-service addition amounts and project expenditures are more accurate, although changes may still arise during the planning process. Drivers of change include:

- prudent scope changes or additions made as project plans mature;
- assumptions made in earlier project phases that are later clarified as site-specific conditions are addressed; and
- risks that either materialize or are mitigated during execution that impact the amount of contingency spent.

3.1 PROGRAM VARIANCES

A large portion of Distribution's capital work program includes investments that are demand in nature and require action in a specified period as part of Hydro One's obligations under Distribution System Code. While Distribution makes every effort to work within its budget, there are times when an influx of demand work results in a reprioritization of resources away from planned work. Hydro One has a robust redirection process that provides the flexibility necessary to reprioritize investments to respond to fluctuations in emergent work while trying to minimize as best it can the impacts of deferring planned investments that can introduce additional risks to the system in future years. Sections 3.1.1 and 3.1.2 provide details on program-level variances in 2019 and 2020, respectively.

3.1.1 2019 PROGRAM-LEVEL VARIANCES

Table 4 provides further detail on 2019 programs with a total budgeted cost greater than $3M. Major variances that resulted in additional expenditures in 2019 compared to the approved expenditure amounts mainly fall into the Emergent Needs and Reprioritization categories based on customer and equipment requirements.

1

Table 4 - Distribution Program Variances 2019

OEB Category	ISD[3]	ISD Description	Net DRO Plan ($M)	Net Actual ($M)	Net Variance ($M)	ISA DRO Plan ($M)	ISA Actual ($M)	ISA Variance ($M)	Units DRO Plan	Units Actual	Units Variance	Variance Type
System Access	SA-01	Joint Use and Line Relocations Program # of poles	16.6	28.8	12.2	17.1	26.9	9.8	1,659	2,339	680	Emergent Needs
	SA-02	Meter Infrastructure Sustainment # of Devices or Meters	17.9	19.6	1.7	20	19.4	-0.6	18,000	25,529	7,529	Emergent Needs
	SA-04	New Load Connections, Service Upgrades, Cancellations and Metering # of Connections, Designs, Upgrades, Cancellations, or Subdivisions	108.9	141.7	32.8	101.8	134.8	33	41,244	37,907	-3,337	Emergent Needs
	SA-05	Generation Connections # of Generation Connections	3.8	6.7	2.9	7.9	8.2	0.3	778	330	-448	Execution Factors
System Renewal	SR-01	Distribution Station Demand Program n/a	4.6	5.6	1	5.3	4.8	-0.5	n/a	n/a	n/a	Emergent Needs
	SR-02	Mobile Unit Substations Program # of MUSs	4.9	6.9	2	3.3	7.2	3.9	3	3	0	Execution Factors
	SR-04	Distribution Station Component Planned Replacement Program # of Components	4.6	5.5	0.9	4.6	5.3	0.7	39	248	209	Work Definition
	SR-08	Distribution Lines PCB Equipment Replacement Program # of Transformers	9.9	8.1	-1.8	9.9	8.1	-1.8	2,735	1,539	-1,196	Execution Factors
	SR-09	Pole Replacement Program # of Poles	53.2	44.3	-8.9	53.2	44.2	-9	6,970	3,984	-2,986	Reprioritization
	SR-10	Distribution Lines Planned Component	7.4	4.9	-2.5	7	4.9	-2.1	4,213	2,469	-1,744	Reprioritization

[3] The ISD numbers presented are the ISD numbers presented in the last distribution application.

OEB Category	ISD[3]	ISD Description	Net DRO Plan ($M)	Net Actual ($M)	Net Variance ($M)	ISA DRO Plan ($M)	ISA Actual ($M)	ISA Variance ($M)	Units DRO Plan	Units Actual	Units Variance	Variance Type
		Replacement # of crossarms replaced, nest relocated, transformers, or sentinel lights										
	SR-11	Component Replacement Submarine Cable # of Submarine Cables	9.1	6.3	-2.8	9.1	6.2	-2.9	245	235	-10	Reprioritization
	SR-12	Distribution Lines Sustainment Initiatives n/a	6.8	8	1.2	11.1	9.4	-1.7	n/a	n/a	n/a	Reprioritization
System Service	SR-07[4]	Distribution Lines Trouble Call and Storm Damage Response Program # of occurrences	12.4	22.1	9.7	12.4	21.5	9.1	842	1,263	421	Emergent Needs
	SS-04	Demand Investments n/a	3.3	4.3	0.9	3.3	4.2	0.9	n/a	n/a	n/a	Emergent Needs
	SS-05	Distribution System Modifications n/a	6.4	7.6	1.1	5.5	7.2	1.7	n/a	n/a	n/a	Emergent Needs
	SS-06	Worst Performing Feeders Program # Devices (Mix of Remotely Operable and Fault Location Devices)	15	21.9	6.9	18.5	18.6	2	745	796	51	Reprioritization

[4]A portion of SR-07 funding is reported in System Service which includes Distribution Capital Post Trouble Call and Distribution Capital Power Quality & Stray Voltage.

The impact of each variance category from a capital expenditure perspective is demonstrated below in Figure 1.

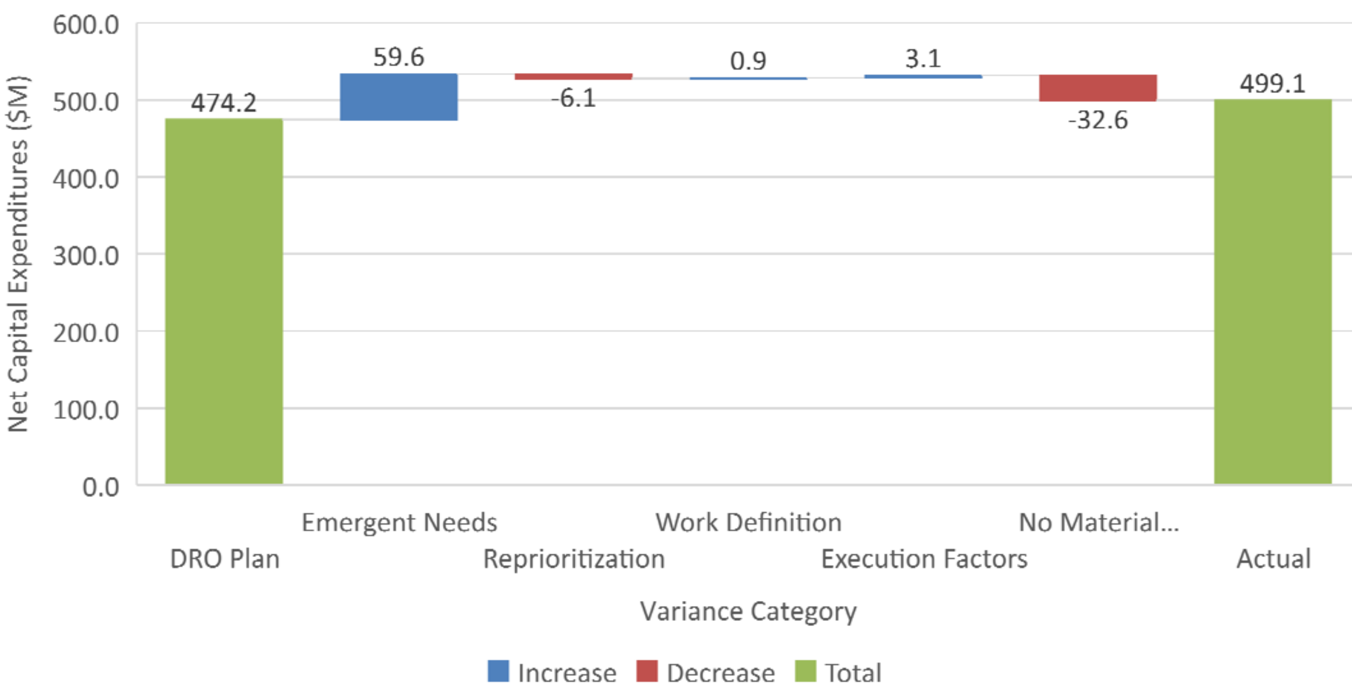

Figure 1: Waterfall chart highlighting the contributions to the 2019 Distribution capital expenditures variance by variance category

- **Joint Use and Lines Relocations Program (D-SA-01):** The Joint Use and Lines Relocations program represented a $12.2M variance to support the influx of requests to access Hydro One's support structure network for the expansion of Telecommunication attachments as well as private customer relocation requests. The variance was categorized as Emergent Needs as Hydro One is required to meet contractual obligations to third parties through Joint Use agreements and to maintain compliance with Hydro One's distributor licence.
- **Meter Infrastructure Sustainment (D-SA-02):** The Meter Infrastructure Sustainment program experienced increased capital expenditures of $1.7M compared to plan as

funding for the Meter Inventory investment is based on projected inventory requirements. Additional purchases were required to accommodate an increase in AMI 1.0 meter failures.

- **New Load Connection, Service Upgrades, Cancellations and Metering program (D-SA-04)**: The New Load Connection, Service Upgrades, Cancellations and Metering program variance accounted for the largest increase within System Access, totalling $32.8M due to higher demand compared to historical trends and was categorized as Emergent Needs. The additional capital expenditure was required to support an increased volume of subdivision designs and connections as well as an upsurge in line expansions and above criteria connections that are more complex, require additional labour hours and therefore more expensive. Service upgrades also experienced an influx in large project requests resulting in increase design and construction costs.
- **Generation Connections (D-SA-05):** Generation Connections was over plan by $2.9M. In addition to increased demand and a large number of FIT connections, the majority of overspend was attributed to one particular investment that required a number of scope changes to facilitate the connection of the generator.
- **Distribution Station Demand Program (D-SR-01):** Capital expenditures exceeded plan by $1M due to the demand nature of the work required. This program involves addressing equipment failures and demand-driven system upgrades that require immediate equipment replacement. As a result, the variance is categorized as emergent needs.
- **Mobile Unit Substations Program (D-SR-02):** The Mobile Unit Substations (MUS) program experienced increased expenditures totalling $2M as a result of additional units that were advanced to 2019 from 2020 due to anticipated supplier issues in 2020.
- **Distribution Station Component Planned Replacement (D-SR-04):** The Distribution Station Planned Component Replacement investment addresses the need to replace individual components in distribution stations on a planned basis. Prior to 2019, this investment primarily focused on the replacement of MUS Structures and replacement of station switches. In 2019, Hydro One added the replacement of oil hydraulic reclosers

with vacuum hydraulic reclosers to this investment, which is expected to lower the lifecycle cost of these reclosers. Overall the program was overspent by $0.9M. The majority of the overage was due to the addition of the hydraulic recloser replacement initiative to the scope.

- **Distribution Lines PCB Equipment Replacement Program (D-SR-09):** The PCB Equipment Replacement program was $1.8M below plan due to fewer proactive replacements compared to the original budget. However, the unit cost was higher due to the complexity of replacements which is dependent on individual design requirements. If replacement is of functional equivalent, unit costs are relatively low but if replacement requires replacement of the pole and transformer for instance, the cost is significantly higher. PCB replacement is driven by the inspection program in which the piece of equipment either fails a PCB test (contains PCB content greater than 45 parts-per-million) or the equipment could not be sampled.
- **Pole Replacement (D-SR-09):** The Pole Replacement program was reduced by $8.9M and completed 2,986 fewer poles compared to plan. The overall reduction in spend was to offset increased capital expenditures required within System Access. Higher unit costs have resulted from the targeted replacement of more critical poles, further reducing the number of poles replaced within the year.
- **Distribution Lines Planned Component Replacement (D-SR-10):** Overall program expenditures were lower than plan by $2.5M as a result of fewer transformers housed in substandard structures replaced. Higher priority demand work limited resources available to complete design and construction work, deferring more complex units to the following year.
- **Component Replacement Submarine Cable (D-SR-11):** Capital expenditures for submarine cable replacement was below plan by $2.8M. This was a result of higher priority demand work that limited resource availability and the early onset of winter that limited access to waterways in the later part of the year.
- **Distribution Lines Sustainment Initiatives (D-SR-12):** This investment includes projects that have historically been categorized into a program. Expenditures for Distribution

Lines Sustainment Initiatives also required an increase to annual expenditures that was the result of reprioritization. The overall impact was an increase of $1.2M compared to plan which was partially offset by projects that were deferred into future years due to reprioritization of customer driven demand work. This included the Owen Sound TSM24 Rebuild Stage 1 and Port ArthurTSM6 Feeder-WestLoon Lake Phases 1&2.

- **Distribution Lines Trouble Call and Storm Damage (D-SR-07):** This portion of SR-07 is reported within System Service and only accounts for two work programs; Dx Capital Post Trouble Call and Dx Capital Power Quality & Stray Voltage. An additional $9.7M was required for Post Trouble Call and Power Quality requests. Post Trouble Calls involve a return trip to permanently repair a temporary fix completed during the initial trouble call. This also includes field initiated requests that field personnel have determined require replacement immediately due to potential safety or reliability concerns. Such requests have increased in demand in recent years and contributed to the increased need for additional spend.
- **Demand Investments (D-SS-04):** Demand Investments involve minor distribution system modifications that ensure adequate supply of electricity to customers by addressing system needs identified by customer power quality complaints, feeder studies and system impact assessments. Increased demand in 2019 resulted in an increase of $0.9M to program expenditures. The variance was deemed to be an Emergent Need as the work is high-priority in nature, with short turn around times that require Hydro One to promptly respond to system needs related to growth and effective operation of the distribution system.
- **Distribution System Modifications (D-SS-05):** Distribution System Modifications is another investment that is driven by customer needs which is focused on correcting feeder load balance, voltage quality and protection coordination issues that arise due to load growth and economic changes. In 2019, the program experienced higher demand than anticipated resulting in an additional $1.1M in capital expenditures that had to be completed in-year.

- **Worst Performing Feeders Program (D-SS-06):** The Worst Performing Feeder program was released with the intent of being completed over multiple years. In 2019, program spend was higher than the approved expenditure levels by $6.9M which is a result of increased program costs due to the limited historical costing data available at the time of plan finalization. In 2019, additional funding was allocated to the program through Hydro One's reprioritization process as this investment was determined to be a cost effective program to mitigate reliability risk on the system.

3.1.2 2020 PROGRAM-LEVEL VARIANCES

Table 5 provides variance details on programs in 2020 with a total budgeted cost greater than $3M. Like 2019, major variances that resulted in additional expenditure in 2020 compared to the approved expenditure amounts mainly fall into the Emergent Needs and Reprioritization categories based on customer and equipment requirements. Another important factor affecting program performance in 2020 was the impact of COVID-19 and modified work procedures implemented to maintain employee safety. For example, implementing one person per vehicle has a slight impact on cost per unit.

Table 5 - Distribution Program Variances (2020)

OEB Category	ISD	ISD Description[5]	Net DRO Plan ($M)	Net Actual ($M)	Net Variance ($M)	ISA DRO Plan ($M)	ISA Actual ($M)	ISA Variance ($M)	Units DRO Plan	Units Actual	Units Variance	Variance Type
System Access	SA-01	Joint Use and Line Relocations Program # of Poles	17.7	26.2	8.5	17.7	24.6	6.9	1,446	10,735	9,289	Emergent Needs
	SA-02	Meter Infrastructure Sustainment # of Devices or Meters	18.3	18.7	0.5	18.4	21.6	3.2	18,000	28,464	10,464	Emergent Needs
	SA-03	AMI Network Expansion # of Devices	9.3	0.1	-9.2	0	0.1	0.1	1,194	0	-1,194	Work Definition
	SA-04	New Load Connections, Service Upgrades, Cancellations and Metering # of Connections, Designs, Upgrades, Cancellations, or Subdivisions	105.6	146.4	40.8	106	147.3	41.4	40,291	40,967	676	Emergent Needs
System Renewal	SR-01	Distribution Station Demand Program n/a	4.8	8.5	3.8	4.7	5.2	0.5	n/a	n/a	n/a	Emergent Needs
	SR-04	Distribution Station Component Planned Replacement Program # of Components	5.1	6.8	1.7	4.8	6	1.3	50	263	213	Work Definition
	SR-06	Distribution Station Refurbishments # of Stations	6.4	7.7	1.3	14.1	7.6	-6.5	0	1	1	Work Definition
	SR-07[6]	Distribution Lines Trouble Call and Storm Damage Response Program # of poles/equipment, transformers, or occurrences	80.2	105.6	25.4	80.2	104.2	24	9,926	1,129,384	1,119,458	Emergent Needs
	SR-08	Distribution Lines PCB Equipment Replacement Program # of Transformers	11	4.8	-6.2	11	4.8	-6.2	2,983	1,026	-1,957	Execution Factors
	SR-09	Pole Replacement Program # of Poles	59.7	43.6	-16.1	59.7	43.5	-16.2	8,158	4,519	-3,639	Reprioritization

[5] The ISD numbers presented are the ISD numbers presented in the last distribution application.
[6] A portion of SR-07 funding is reported in System Service which includes Distribution Capital Post Trouble Call and Distribution Capital Power Quality & Stray Voltage.

OEB Category	ISD	ISD Description[5]	Net DRO Plan ($M)	Net Actual ($M)	Net Variance ($M)	ISA DRO Plan ($M)	ISA Actual ($M)	ISA Variance ($M)	Units DRO Plan	Units Actual	Units Variance	Variance Type
	SR-10	Distribution Lines Planned Component Replacement # of crossarms replaced, nest relocated, transformers, or sentinel lights	4.1	6.3	2.2	4.1	6.3	2.2	4,069	3,013	-1,056	Reprioritization
	SR-11	Component Replacement Submarine Cable # of Submarine Cables	9.7	6.7	-3	9.7	6.6	-3.1	230	298	68	Reprioritization
	SR-12	Distribution Lines Sustainment Initiatives n/a	16.3	11.2	-5.1	12.8	9.8	-3	n/a	n/a	n/a	Reprioritization
System Service	SS-04	Demand Investments n/a	3.6	2.9	-0.7	3.4	3.7	0.3	n/a	n/a	n/a	Emergent Needs
	SS-05	Distribution System Modifications n/a	3.7	6.9	3.1	5.4	7.2	1.9	n/a	n/a	n/a	Emergent Needs
	SS-06	Worst Performing Feeders Program # Devices (Mix of Remotely Operable and Fault Location Devices)	15.8	20.7	4.9	15.8	20.7	4.9	786	799	13	Reprioritization

The impact of each variance category from a capital expenditure perspective is demonstrated below in Figure 2.

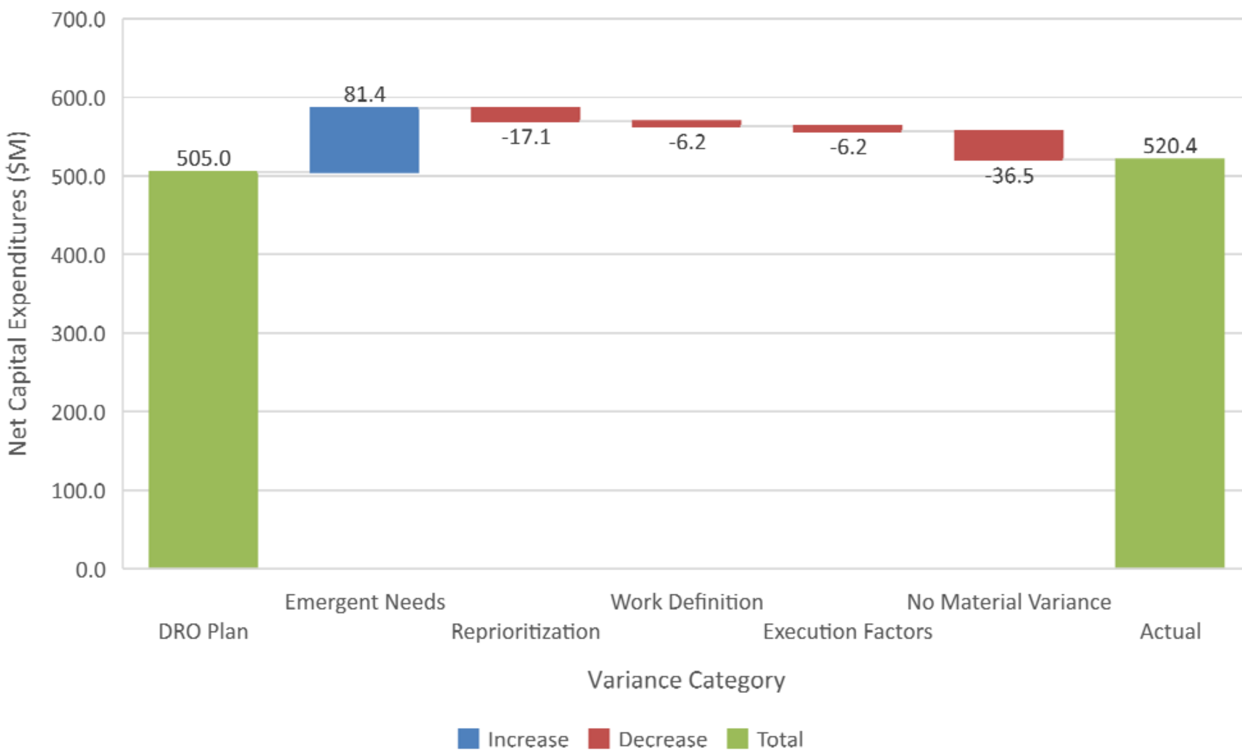

Figure 2: Waterfall chart highlighting the contributions to the 2020 Distribution capital expenditures variance by variance category

- **Joint Use and Lines Relocations Program (D-SA-01):** The Joint Use and Lines Relocations program continued to experience an influx of requests for access to Hydro One's support structures by Telecommunication Companies. As this program is budgeted based on historical demand analysis, an additional $8.5M was required to meet obligations to third parties through Joint Use agreements. Hydro One was able to manage a portion of this influx by contracting the construction of make-ready work in certain high demand locations, which provided some relief for internal resources.
- **Meter Infrastructure Sustainment (D-SA-02):** The Meter Infrastructure Sustainment program experienced increased capital expenditures compared to plan by $0.5M as

funding for the Meter Inventory investment is based on projected inventory requirements. Additional purchases were required to accommodate an increase in AMI 1.0 meter failures.

- **Meter Infrastructure Expansion Program (D-SA-03):** This planned investment of $9.2M to continue to expand the AMI 1.0 network to reach additional customers through leveraging ongoing Telecommunications Carrier upgrades was cancelled. Following detailed field investigation and testing it was determined that the cost per new customer added to the network was not economic.
- **New Load Connection, Service Upgrades, Cancellations and Metering program (D-SA-04**): An increase of $40.8M was necessary to meet increased demand compared to plan and was categorized as Emergent Needs. The additional capital expenditure was required to support an increased volume of line expansion requests that are more costly than lies along connections and a continued rise in subdivision designs and connections. An increase in large connection and upgrade projects also continued to trend in 2020, of which 66% of the projects were in the Essex area that continues to experience load growth.
- **Distribution Station Demand Program (D-SR-01):** Capital expenditures exceeded by $3.8M due to the demand nature of the work required. This program involves addressing equipment failures and demand-driven system upgrades that required immediate equipment replacement. As a result, the variance is categorized as emergent needs.
- **Distribution Station Component Planned Replacement (D-SR-04):** The Distribution Station Planned Component Replacement investment addresses the need to replace individual components in distribution stations on a planned basis. Prior to 2019, this investment primarily focused on the replacement of MUS Structures and replacement of station switches. In 2019, Hydro One added the replacement of oil hydraulic reclosers with vacuum hydraulic reclosers to this investment, which is expected to lower the lifecycle cost of these reclosers. Overall the program was overspent by $1.7M in 2020.

The majority of the overage was due to the addition of the hydraulic recloser replacement initiative to the scope.

- **Distribution Station Refurbishments (D-SR-06):** Station refurbishments aim to correct deficiencies in power transformers or other station equipment to prevent significant outages from occurring. The program incurred a $1.3M increase in 2020 which is a result of reprioritization efforts of work originally planned to be completed in 2019 that was deferred to 2020 due to scoping decisions.
- **Distribution Lines Trouble Call and Storm Damage (D-SR-07):** This portion of SR-07 includes the following investments; Dx Capital Trouble Call Poles & Equipment, Dx Capital Storm Damage, Dx Capital Trouble Sub and UG Cable and Dx Capital Trouble Call Damage Claims. An increase of $25.4M to Distribution Lines Trouble Call and Storm Damage was required mainly due to significant storm activity in mid-November, which represented $21M above the three-year historical average for November. It should also be noted that the unit of measure for storm damage was changed in 2020 to the number of customers impacted as opposed to number of occurrences that was used historically. The number of customers impacted in 2019 was approximately 800,000 compared to approximately 1,100,000 in 2020.
- **Distribution Lines PCB Equipment Replacement Program (D-SR-09):** The PCB Equipment Replacement program was $6.2M below plan due to lower volume of replacements which was also a result of work suspension in March due to COVID-19 restrictions. The unit cost was also lower than expected as more transformer replacements of the same functional equivalent were installed.
- **Pole Replacement (D-SR-09):** The Pole Replacement program was reduced by $16.1M and completed 3,639 fewer poles compared to plan. Program spend was impacted as a result of COVID-19 measures implemented in March that resulted in suspension of the work program temporarily. Higher priority demand work impacted the ability to replace more units and offset increased capital expenditures required within System Access. To mitigate impacts to the Pole Replacement program, the organization worked towards a prioritized list to address higher priority poles where possible. Higher unit costs have

resulted from the targeted replacement of more critical poles, however unit costs in 2020 were reduced compared to the previous year largely due to improved work planning.

- **Distribution Lines Planned Component Replacement (D-SR-10):** Overall program expenditures were higher than plan by $2.2M largely due to increased sentinel light costs and a slight increase to the crossarm and nest replacement programs.
- **Component Replacement Submarine Cable (D-SR-11):** Capital expenditures for submarine cable replacement was below plan by $3M. This was a result of higher priority demand work that limited resource availability. Modified work procedures and delayed access to waterways as a result of COVID-19 further impacted the ability to complete the program as planned.
- **Distribution Lines Sustainment Initiatives (D-SR-12):** This investment includes projects that have historically been categorized into a program. Expenditures for Distribution Lines Sustainment Initiatives were less than plan by $5.1M in 2020. This was a result of reprioritization that lead to the addition or removal of projects against the original plan. Storm events late in the year resulted in deferral of work to 2021, forcing further reductions in spending compared to plan.
- **Demand Investments (D-SS-04):** Demand Investments involve minor distribution system modifications that ensure adequate supply of electricity to customers by addressing system needs identified by customer power quality complaints, feeder studies and system impact assessments. The program was $0.7M below approved expenditure levels due to lower demand.
- **Distribution System Modifications (D-SS-05):** Distribution System Modifications is another investment that is driven by customer needs focused on correcting feeder load balance, voltage quality and protection coordination issues that arise due to load growth. In 2020, the program experienced higher demand than anticipated resulting in an additional $3.1M in capital expenditures that were linked to customer connections.
- **Worst Performing Feeders Program (D-SS-06):** In 2020, program spend was higher than approved expenditure levels by $4.9M which is a result of work in 2019 that was carried

over to 2020 and increased program costs due to the limited historical costing data available at the time of plan finalization. Some execution challenges were also a factor due to outage constraints and coordination efforts with other internal lines of business.

3.2 PROJECT VARIANCES

The Distribution capital envelope is predominantly program-based, with smaller scale projects. However, some large System Service investments are required to ensure the system can accommodate new connections and growing communities. There are circumstances where projects will span over multiple years, such as the dynamics of demand-driven work and project variables that require efficient redirection of resources. Accordingly, Hydro One focuses on adherence to the total project cost rather than adherence to in-year expenditures.

3.2.1 2019 PROJECT-LEVEL VARIANCES

Table 6 summarizes the projects that met the criteria of a major variance for either timing, scope or cost with detailed explanations for each listed below. As the Distribution capital work program is largely comprised of programs and smaller projects, few projects meet the $3M threshold for providing a variance explanation.

Table 6 - Capital Project Variances (2019)

OEB Category	AR Name	Project Phase ($M)	Net DRO Plan ($M)	Net Actual ($M)	ISA DRO Plan ($M)	ISA Actual ($M)	Net DRO Plan Project Total ($M)	Net Project End Forecast ($M)	Project End Variance ($M)	Net LTD Actual ($M)	DRO Plan IS Year	Forecast/Actual IS Year	Date Variance (Years)	Variance Req'd
System Service - Unassigned	Nakina DS F2 BESS 25451	Execution	8	1.3	8.1	0	8.1	8.3	0.2	1.4	2019	2021	2	Yes
System Service - SS-02 System Upgrades Driven by Load Growth	Kirkland Lake Voltage Conversion - Stage 1 23080	Execution	3.8	0.2	4.6	0	4.6	7.8	3.2	1	2021	2021	0	Yes
	Leamington TS Feeder Development 23304	Execution	2	4.8	2.5	5.3	21.5	34.5	13	34	2019	2019	0	Yes
	Leamington TS DESN2 Feeder Development 25285	Execution	30.2	22.5	0	11.9	41.1	53.6	12.5	52.1	2020	2020	0	Yes

Nakina DS F2 BESS: This project investment is a pilot initiative for a Hydro One owned and operated Battery Storage facility in rural Ontario which is intended to provide backup power to the Aroland First Nation community where the community has been susceptible to prolonged outage durations. The project incurred increased costs as a result of complexities in finalization of the engineering design, COVID-19 restrictions, construction, commissioning and in-servicing which has also resulted in delays to the original in-service date.

Kirkland Lake Voltage Conversion Stage 1: The overall project scope involves the conversion of the Goodfish Distribution Station feeders and refurbishment of the existing station to meet load growth needs in the area and address end-of-life assets. After estimate completion, Hydro One determined that the project costs would be higher than the approved investment as outlined in the 2018-2022 Distribution Rate Order. Given the significant forecasted load growth and condition of existing assets, the increased costs of the investment were addressed through Hydro One's redirection process to minimize the risk of overloading feeders, unsupplied load and reliability issues.

Leamington TS Development: As an outcome of the Supply to Essex Country Transmission Reinforcement project, it was identified that there was a need to have a separate project to build new and modify existing distribution assets to complete the transmission project. The Leamington TS Development project involved relocation of a distribution line as well as the installation of eight new distribution lines from Leamington Transformer station. This would become the largest Distribution project the organization had completed. The cost of the project was $13M higher than originally anticipated due to the unforeseen need to enhance the system with larger distribution poles to enable additional load requirements and the reconfiguration of distribution line lengths and routes.

3.2.2 2020 PROJECT-LEVEL VARIANCES

Table 7 provides an overview of 2020 projects over the $3M threshold. Many of the projects listed are still within the planning stage with current variances mainly attributed to reprioritization of projects and a shift from the original investment plan with minimal spend allocated to cover design costs prior to project approval. Of the listed projects, Enfield TS Feeder Development and Leamington DESN2 Feeder Development are completed projects with material variances.

1

Table 7 - Capital Project Variances (2020)

OEB Category	AR Name	Project Phase	Net DRO Plan ($M)	Net Actual ($M)	ISA DRO Plan ($M)	ISA Actual ($M)	Net DRO Plan Project Total ($M)	Net Project End Forecast ($M)	Project End Variance ($M)	Net LTD Actual ($M)	DRO Plan IS Year	Forecast/Actual IS Year	Date Variance (Years)	Variance Req'd
System Renewal – SR-13 Life Cycle Optimization and Operational Efficiency Projects	Eugenia RS - 44kV Pole Mount Regulators 23374	Planning	3.3	0	4.3	0	4.3	1.1	-3.2	0.7	2022	2022	0	Yes
System Service – SS-02 System Upgrades Driven by Load Growth	Awenda DS F1 Upgrade Supply to Christian Island 23863	Planning	2.8	0	3.5	0	3.5	0.3	-3.2	0.3	2021	2022	1	Yes
	New Old School DS and feeders 24053	Planning	11.2	0.8	11.6	0	11.6	0.1	-11.5	0.8	2021	2021	0	Yes
	Enfield TS Feeder Development 24171	Execution	3.3	3.2	11.2	10.4	11.2	10.7	-0.5	10.4	2019	2020	1	Yes
	Brockville 44kV Load Growth 24453	Planning	9.1	0.3	10	0	10	0.5	-9.5	0.5	2021	2022	1	Yes
	Leamington TS DESN2 Feeder Development 25285	Execution	10.5	29.3	41.1	40.2	41.1	53.6	12.5	52.1	2020	2020	0	Yes
System Service - SS-02 System Upgrades Driven by Load Growth	Wikwemikong Supply - Station & Line Work 25740	Planning	6.1	0.2	6.3	0	6.3	1	-5.3	0.3	2022	2022	0	Yes
	Barrie TS - Construct new feeders 25798	Planning	5.6	0.1	5.8	0	5.8	0.1	-5.7	0.1	2021	2022	1	Yes

Witness: NG Chong Kiat

Enfield TS Feeder Development: This investment involved building two new 44kV feeders from Enfield TS to enable the transfer of approximately 40MW from the existing Wilson TS M12 and M13 feeders. The project included 14.5 kilometers of single circuit overbuild and 2 kilometers of double circuit overbuild and required the movement of existing distributed generation (DG) customers to the new feeders as well as a change in the DG customers' tele-protection. The project was in-serviced in late 2020 with overall spend slightly below the approved expenditure amount which does not meet variance threshold requirements. However, there was a delay in project completion which was a result of changes made to the project scope after release as well as challenges with telecommunication lines properly communicating with the DG customers.

Leamington TS DESN2 Feeder Development: The overall scope of the Leamington TS DESN2 Feeder Development project involved the construction of underground and overhead distribution feeders totalling 56 kilometers in length. The project supported the connection of 220 MW of new greenhouse industry load and provided a more reliable distribution system for existing customers. The increased funding required to support this investment was addressed through Hydro One's redirection process as the Leamington area experienced rapid load growth and requests from greenhouse customers to connect on time to meet critical growing season schedules that were dependent on the completion of this project. The design of the underground duct bank took significantly longer than estimated due to unanticipated complexities including a high volume of existing utilities in the ground that had to be avoided and an underground private feeder that was identified later in the project that required relocation. Further delays were experienced with the construction of the duct bank as a number of manufacturing defects were identified and as a result of these delays, lines construction crews had to re-sequence their execution plan to prioritize customer connection dates. The combination of these factors resulted in the need for additional spend and delayed the project in-service timeline.

4.0 CONCLUSION

Hydro One Distribution has demonstrated the ability to deliver a large and complex capital work program and has the capability of adjusting to meet the needs of its customers. Although capital expenditures were slightly over approved levels in 2019 and 2020, the organization adapted to significant increases in demand requests and weather events to minimize the overall impact to the capital portfolio. This required prioritization of planned work to maintain a safe and reliable distribution network within the year while addressing future year risk and opportunities. As demand investments continue to experience fluctuating volumes, the organization remains focused on improving its planning strategies while leveraging flexibility within its workforce. Maintaining robust oversight over the distribution work portfolio and continuing to identify efficient and cost.

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ACQUIRED UTILITIES

1.0 INTRODUCTION

The purpose of this Attachment 3 is to provide information related to capital expenditures that are unique to the Acquired Utilities[1] until December 31, 2022. All three of the Acquired Utilities have been integrated into Hydro One operations and planning. However, the Acquired Utilities have been excluded from capital expenditures and in-service additions until January 1, 2023, the date they will be integrated into Hydro One for rate-making purposes. Historical fixed asset and rate base information is provided in Section 3 below.

2.0 CAPITAL EXPENDITURE SUMMARY

Table 1 below presents a summary of capital expenditures for the Acquired Utilities up to December 31, 2022.

[1] As previously indicated in this Application, the Acquired Utilities are the former Haldimand County Hydro Inc., Norfolk Power Distribution Inc., and Woodstock Hydro Services Inc.

Table 1 - Historical and Forecast Expenditures[2] ($M)

	Historical			Forecast	
LDC/Category	**2018**	**2019**	**2020**	**2021**	**2022**
Haldimand County Hydro Inc.					
System Access	1.8	1.5	1.9	2.7	2.9
System Renewal	1.6	1.3	1.3	1.7	2.1
System Service	0.1	0.0	0.1	0.1	0.5
General Plant	-	-	-	-	-
Sub Total	**3.5**	**2.8**	**3.2**	**4.5**	**5.5**
Norfolk Power Distribution Inc.					
System Access	1.0	1.4	0.7	1.6	1.6
System Renewal	0.9	0.9	2.0	3.1	2.6
System Service	0.1	0.0	0.0	0.2	0.2
General Plant	-	-	-	-	-
Sub Total	**2.0**	**2.3**	**2.6**	**4.9**	**4.4**
Woodstock Hydro Services Inc.					
System Access	1.0	0.9	0.9	1.2	1.3
System Renewal	0.8	0.5	1.6	2.0	1.4
System Service	0.0	0.0	0.0	0.3	0.3
General Plant	-	-	-	-	-
Sub Total	**1.8**	**1.4**	**2.5**	**3.5**	**3.1**
Grand Total	**7.3**	**6.4**	**8.3**	**12.9**	**13.0**

The historical and forecast periods are discussed further in the following sections.

2.1 HISTORICAL CAPITAL EXPENDITURE TRENDS

This section discusses capital expenditures for the acquired utilities for the historical years. Hydro One Distribution's historical (actual) capital expenditures across all Acquired Utilities for the years 2018-2020 were $22M. The Haldimand County service area accounted for slightly more expenditures ($9.5M) than the other Acquired utilities, with the remaining expenditures distributed between the Norfolk service area ($6.9M) and Woodstock service area ($5.7M). Across all three Acquired utilities, the most significant expenditures over the 2018-2020 period were:

- New Connections and Upgrades;
- Trouble Calls and Storm Response; and

[2] Historical and forecast expenditures shown align with Hydro One Distribution's previous Custom IR period.

- Renewal of lines assets including pole replacements.

The remaining expenditures were largely attributable to Metering Sustainment and Stations Demand / Emergency Capital.

2.2 FORECAST CAPITAL EXPENDITURE TRENDS

This section discusses forecast capital expenditures for the acquired utilities for the current and bridge years (2021-2022). The 2021-2022 period is considered a forecast period and discussed separately for the acquired utilities, since for the years 2023 and beyond, the acquired utilities are integrated in Hydro One's Distribution System Plan.

Total expenditures across all Acquired Utilities for the 2021-2022 period is forecast to be $25.9M. The bulk of expenditures in the forecast period are related to performing work for new connections and storm response. Where prudent, Hydro One has also addressed asset condition and capacity limitations, to maintain operability and system performance in these areas of its distribution system. Details of the expenditures for each Acquired Utility service area are as follows:

2.2.1 HALDIMAND

Forecast expenditures within Haldimand are anticipated to increase, mainly due to an increase in expenditures related to new connections and trouble calls & storm response. In addition, moderate expenditure increases are also forecast in 2022 for the following:

- Wood pole replacements and refurbishments to address poor condition poles and the chemical retreatment of poles at the ground line; and
- Investments to accommodate localized growth and maintain power quality.

2.2.2 NORFOLK

Forecast expenditures for Norfolk are anticipated to increase, mainly due to an increase in expenditures related to new connections and trouble calls & storm response. Moderate expenditure increases are also forecast for the following:

- Renewal of lines assets in 2021 and 2022 that includes relocation of poor condition off-road assets to within road allowance, to improve reliability and accessibility;
- Wood pole replacements and refurbishments in 2021 to address poor condition poles and the chemical retreatment of poles at the ground line; and
- Address stations assets in 2021 & 2022 that have exhibited operational issues.

2.2.3 WOODSTOCK

Forecast expenditures for Woodstock are anticipated to increase, mainly due to an increase in expenditures related to new connections, and trouble calls & storm response. Expenditure increases are also forecast to address the following:

- Renewal of lines assets to replace poor condition, 4.16kV, underground assets with 27.6kV assets which will maintain the reliability of supply, and will also improve operational efficiencies by standardizing on a single delivery voltage; and
- Investments to accommodate localized growth and maintain power quality.

3.0 HISTORICAL FIXED ASSETS AND FORECAST RATE BASE

Tables 2 to 4 below show the historical fixed assets and forecast rate base for each of the Acquired Utilities up to 2022. The 2022 closing balances of the Acquired Utilities have been added to the Hydro One Distribution 2023 opening balances such that all figures shown for 2023-2027 in Exhibit C (rate base) are presented on a combined basis.[3]

[3] As indicated in Exhibit C-01-01 footnote 2, 2023-2027 figures are presented on a combined basis including Acquired Utilities. See also Exhibit C-04-01, C-04-02 and C-04-03.

Table 2 - Haldimand Historical Fixed Assets and Forecast Rate Base ($M)

Year End Fixed Assets	2014	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Plan	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
Utility Plant (Year End)										
Gross Plant at Cost	80.1	79.7	53.4	56.1	58.7	62.3	67.6	69.1	75.0	80.9
Less: Accumulated Depreciation	(32.2)	(32.0)	(0.9)	(2.8)	(4.1)	(5.5)	(6.6)	(8.2)	(10.2)	(12.3)
Net Plant	**47.8**	**47.7**	**52.5**	**53.3**	**54.6**	**56.8**	**61.0**	**60.9**	**64.8**	**68.6**
Average Net Plant	-	-	-	-	-	-	-	-	62.9	66.7
Working Capital	-	-	-	-	-	-	-	-	2.8	2.8
Rate Base	-	-	-	-	-	-	-	-	**65.7**	**69.5**

Table 3 - Norfolk Historical Fixed Assets and Forecast Rate Base ($M)

Year End Fixed Assets	2012 Plan	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast
Utility Plant (Year End)												
Gross Plant at Cost	84.7	83.6	86.9	56.6	56.2	59.0	63.2	65.5	64.6	65.9	70.0	74.1
Less: Accumulated Depreciation	(30.8)	(29.7)	(32.1)	(0.8)	(2.8)	(4.3)	(5.8)	(7.6)	(8.4)	(8.4)	(10.1)	(11.8)
Net Plant	**53.9**	**53.9**	**54.8**	**55.8**	**53.4**	**54.7**	**57.4**	**57.9**	**56.2**	**57.5**	**60.0**	**62.3**
Average Net Plant	-	-	-	-	-	-	-	-	-	-	58.7	61.1
Working Capital	-	-	-	-	-	-	-	-	-	-	2.4	2.4
Rate Base	-	-	-	-	-	-	-	-	-	-	**61.1**	**63.6**

Table 4 - Woodstock Historical Fixed Assets and Forecast Rate Base ($M)

Year End Fixed Assets	2011 Plan	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast
Utility Plant (Year End)													
Gross Plant at Cost	42.3	44.6	45.2	48.9	52.1	27.2	28.6	30.3	31.6	32.9	35.7	41.8	44.8
Less: Accumulated Depreciation	(19.1)	(19.3)	(20.7)	(22.6)	(24.1)	(0.1)	(1.4)	(2.3)	(3.0)	(3.4)	(4.2)	(5.2)	(6.3)
Net Plant	**23.1**	**25.3**	**24.4**	**26.3**	**28.0**	**27.1**	**27.2**	**28.0**	**28.6**	**29.5**	**31.5**	**36.6**	**38.5**
Average Net Plant	-	-	-	-	-	-	-	-	-	-	-	34.0	37.5
Working Capital	-	-	-	-	-	-	-	-	-	-	-	2.5	2.6
Rate Base	-	-	-	-	-	-	-	-	-	-	-	**36.6**	**40.1**

SECTION 3.10 – DSP – CAPITAL WORK EXECUTION STRATEGY

3.10.1 INTRODUCTION

This exhibit describes how Hydro One delivers its work program within approved expenditure levels, while maintaining the necessary flexibility to adjust as required. The Distribution and Transmission work programs are executed in different ways based on the types of investments and how work must be planned and executed. The Distribution work portfolio is predominantly program-based with smaller scale projects compared to Transmission. Distribution is required to respond to a much higher volume of demand work with shorter turnaround times. To succeed in this complex operating environment, Distribution has a nimble and dynamic process for re-prioritizing and transitioning from planned to demand work as required. The challenges and associated measures put in place to maintain portfolio health are explained below.

3.10.2 CAPITAL DELIVERY PROCESS

The capital delivery process starts with the planning and prioritization of capital work through Hydro One's Asset Management and Investment Planning process (see SPF Section 1.6). As discussed there, capital work is planned to address asset condition and anticipated system needs using a risk based approach. The product of the planning process is a series of investment needs that are met through the development of capital programs and projects.

As Distribution's work portfolio is largely driven by non-discretionary investments, the organization can be faced with the need to re-prioritize planned activities to meet demand obligations. This includes leveraging flexible resource options, governance oversight to frequently monitor risks and opportunities, and identifying opportunities to become more efficient in planning, scheduling and executing work programs.

3.10.2.1 PROGRAM AND PROJECT WORKFLOW PROCESS

Hydro One uses a formal work acceptance and release process for both planned and demand work programs and projects. The workflow process attempts to minimize any impacts to planned work resulting from volatility in demand work, which is forecasted based on historical peaks in demand and customer work requests. The planning process helps ensure that sufficient time is allocated for:

- ordering materials with long lead times;
- coordinating with other capital or maintenance work;
- coordinating with other internal and external work groups;
- securing outages and optimize bundling and reliability improvements; and
- scheduling work when site conditions are optimal.

For planned program work, a scope of work is issued annually whereby specific accomplishments identified for replacement in the system are funded by Asset Planning based on risk-assessment and priority. This information is provided to Program Managers within the Distribution Work Management team who review and allocate accomplishments across all operations centres, subsequently releasing this information to the Field Business Centres (FBC) for review. New asset installation is also a scenario and the scope of work indicates the specific locations new equipment is to be installed which is typically driven by reliability and feeder performance data. The role of the FBC is to review the high level plan and determine the most efficient way to plan and schedule the work programs across the respective regions. The utilization of technology such as Geographic Information System mapping in the upfront planning process to drive efficiencies in cross-program planning and execution. Once the accomplishment selection process is completed and bundled where possible, the FBC coordinates technician resources to prepare the necessary designs before execution crews can be scheduled.

Project investments follow a similar pattern where an initial scope of work is produced and the investment is initially released for design and estimating purposes only. It is not until the project receives formal approval to construct, that funding is released and the FBC, working with the Project Manager, begins planning and scheduling of resources in addition to ordering materials. If possible, project and program work is coordinated together to maximize outage windows, resource utilization and reduce mobilization and demobilization efforts and costs.

Due to the demand nature of Distribution's work program, historical peaks in demand are utilized to inform how planned investments are scheduled, with the goal of minimizing interruptions and delays to planned work as much as possible. Seasonal factors are also taken into consideration, particularly in the summer months where high density cottage areas experience an influx in requests. When demand requests are higher than expected, the FBCs adjust schedules to accommodate priority work which could result in shifting of resources across operations centers as a means of ensuring required work is completed. Scheduling of dedicated crews for demand work such as trouble calls is another strategy used to ensure interruptions to planned work is minimized, while maintaining the necessary flexibility to address emergent and demand related requests. If demand work does not materialize as expected, the FBC can advance planned program work based on resource and equipment availability or move resources to support neighbouring areas where volumes of work remain elevated.

As the Distribution organization requires a nimble strategy, it is imperative that planning and execution strategies are coordinated to achieve operational effectiveness. Detailed job planning and frequent communication between crew members and supervisors is emphasized as key communication elements for incident prevention and operational efficiency. By ensuring Distribution's frontline workers and supervisors are well informed of potential risks, and are actively engaged in safe work planning, workplace health and safety continues to improve, resource deployment is optimized and execution delays are minimized where possible. This leads to a reduction in crew mobilization and demobilization keeping overall costs to a minimum.

The Distribution organization is placing increased focus on strategic planning and scheduling which will lead to improved visibility to upcoming work. This enables the organization to bundle various work programs under a common work plan by geographic areas with the ability to advance lower priority work provided it can be done more efficiently. Bundling of work reduces crew windshield time and the number of required mobilization and demobilization activities for field staff; drives effective resource, fleet and material planning; optimizes outage requirements; and allows the organization to be more cost efficient. Further details on this can be found in this Exhibit under section 6.1 Productivity.

3.10.2.2 CAPITAL PROGRAMS

Planned work programs are driven by asset condition and reliability, and are undertaken to control future risks and minimize operational costs. Hydro One strategically selects replacement units based on priority and identified criteria to determine annual work programs. Wood Pole, Meter, PCB Transformer, Submersible cable and Component Replacements are major investments within the Distribution planned portfolio. Planned program work also involves new asset installation such as Communicating Fault Current Indicators where units are determined based on worst performing feeder data and optimal installation locations are selected to drive reliability improvements. Other factors that may be taken into consideration due to the impact on execution and associated unit costs include:

- **Location:** replacement costs vary by region
- **Voltage Level:** LV (M-Class) poles are larger in size and typically have more attachments
- **Setting:** costs vary depending on whether the pole is set in earth, rock, etc.
- **Accessibility:** off-road or high-density areas present additional installation challenges

Demand work is a mix of System Renewal and System Access investments driven by customer's who are connected to or intend to connect to Hydro One's distribution network. These work programs are forecasted based on historical demand analytics, however external factors can have a significant impact on demand volumes, resulting in program fluctuations. Historically, demand work accounts for approximately 65% of Distribution's capital expenditures. Of the demand work, major investments include New Connections (46%), Trouble and Storm restoration efforts (39%), Joint Use and Relocations (15%).

New Connections are defined as new customers that request connection at locations that "lie along" Hydro One's existing distribution network. This portfolio also includes Customer Expansions, which result in capacity increases and Service Upgrades, which involve a change in the customer's service that requires modifying Hydro One owned plant to meet the customer's requirements. The New Connection program is measured by an OEB Service Quality Indicator (SQI) target. This requires Distributors to connect new customers who have satisfied all connection requirements within 5 days, 90% of the time. Hydro One continues to plan and resource the work program accordingly, consistently meeting the target, despite increased volumes the program has experienced in recent years.

Distribution's trouble response program accounts for capital costs related to locating and restoring power outages; responding to and resolving power quality complaints made by customers; and identifying and correcting abnormal system conditions. Storm restoration is categorized as emergency work on Distribution assets following major storms, which exceed the threshold of trouble call response. Both of these programs are critical to maintaining a safe and reliable distribution network, with impacts to required funding and resources when more frequent or severe weather-events occur compared to historical trends.

The Joint Use and Relocation program is responsible for work that is necessary for Hydro One to meet contractual obligations to third parties through Joint Use agreements and occupation agreements with Road Authorities for distribution facilities located on road allowances. As Hydro One is required to comply with legal, contractual and statutory obligations, this work is considered non-discretionary and demand in nature. Increased volumes are anticipated in future years to support the Ontario Government's significant investment to improve high speed internet in rural communities and accommodate the upsurge in fibre attachment requests.

3.10.2.3 CAPITAL PROJECTS

Similar to how program work is planned, capital project investments are developed by Asset Planning based on asset-related needs and risks, particularly on the basis of asset condition, utilization and performance. Some projects are also developed to address load growth and facilitate customer connections. Projects of discretionary nature are prioritized based on a balance of risk mitigation and benefits relative to costs. In general, projects are first released to Distribution Work Management to provide design and estimates for the work. Following a review of the estimate and if approval is granted by Asset Planning, the project is released to the Project Manager for construction.

Capital projects are categorized into System Renewal and System Service investments, which is dependent upon the scope of the work. System Renewal investments are defined as improvements to existing assets and do not include any system enhancements. System Service investments provide new or modified distribution system facilities to accommodate system upgrades driven by load growth; optimize asset life cycle and operational efficiency; and improve system reliability.

Within the System Renewal and System Service envelopes, there are two sub-categories that Distribution projects can be classified; program-based projects and major projects. Program-based projects are typically planned, executed and in-serviced within a year, with the overall investment less than $300,000. Approval to proceed with construction once the detailed estimate is complete is based upon priority and availability of annual funding.

Major projects are those that exceed the $300,000 investment threshold and typically span over multiple years. Formal Business Case approval is required once the detailed design and estimate is complete and total project costs are known. Approval and signoff follows the organizational authority limits which varies depending upon the total cost of the project. Once approved for construction, projects are monitored and scrutinized at multiple levels to ensure that material changes to scope, schedule or cost exceeding the 10% variance threshold are identified and properly approved.

There is a need to maintain flexibility with the timing of Distribution project investments due to the non-discretionary nature of Distribution's capital portfolio. If adjustments are necessary to meet requirements of demand programs, adjustments to in-service dates or scope may be required and resources re-prioritized. Other factors that are considered in the assessment of overall project schedules include design and estimate status, resource requirements, interbusiness commitments, impacts to outage plans and potential implications to projects tied to customer-driven requests.

Distribution projects do not proceed with construction until the design and estimate is finalized and formal business case approval is granted. If the design and estimate stage takes longer than predicted, this can impact project timelines before construction commences. Project plans and forecasts are refined throughout the planning process as the organization gathers information about outage availability, worksite and seasonal conditions, long-lead materials as well as labour and equipment requirements. This can lead to variances between the initial and final project scope, budget or project in-service date. The above mentioned variances are less common for programs which consist of more predictable, repetitive work.

3.10.3 PROJECT OVERSIGHT

Hydro One maintains robust oversight over its distribution work portfolio, with significant improvements made in recent years to drive necessary program and project management and improve forecasting and reporting capabilities. Investments are monitored and scrutinized at multiple levels to ensure that material changes to scope, cost or schedule are identified. Monthly governance meetings are held to review forecasts and performance results. This also involves review of demand trends to evaluate risks and opportunities. Portfolio progress and risk-assessments are compiled for review by senior leadership to facilitate key business decisions and ensure the health of the overall portfolio is maintained. In addition, detailed monitoring and reporting is provided regionally to highlight local performance and any risks by tracking costs, unit accomplishments and schedule performance.

If funding adjustments are required, there is a thorough re-direction process that is initiated through the Redirection Committee (SPF Section 1.7). The Redirection Committee will provide advice and direction on investment adjustments that are required to the business plan to address emerging business needs or to seize opportunities related to the planning and execution of Hydro One's Investment Plan.

3.10.4 FACTORS IMPACTING WORK EXECUTION

3.10.4.1 EXECUTION RESOURCES AND APPROACH

Distribution's resource strategy is designed to ensure that the organization safely and efficiently delivers its work program within approved expenditure levels, while maintaining commitments to Hydro One customers. A work-based approach to staffing is utilized, whereby Hydro One sources staff according to work programs rather than planning the work around the number of internal resources available. Similarly, overtime is used as required to manage demand work when there is a conflict with planned or other priority work.

To address the fluctuating and seasonal nature of Distribution's work program, the organization maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, hiring hall, and temporary staff, as well as qualified vendors. This also includes utilizing Hydro One's apprenticeship and training programs with the guidance of experienced tradespersons and technicians to learn the required skills and support various programs and projects within Distribution Lines. Distribution also has the ability to utilize Transmission project crews to support work programs and projects across the province. This has included major System Renewal and System Access projects, Pole Replacement, Joint Use as well as New Connection and Upgrade work.

Despite increases to planned work, the Distribution organization intends to maintain a relatively flat level of regular status full-time equivalents (FTEs) throughout the rate period. In the Distribution organization, regular FTEs are Power Workers' Union (PWU)-represented and Society of United Professionals (Society)-represented staff, or are members of management that are not represented. Anticipated hiring into regular status PWU or Society roles is primarily limited to the level required to contend with attrition. During the 2023-2027 period, there will be limited increases in casual status FTEs (casual employees in Distribution lines of business are members of the PWU Hiring Hall, or members of a Building Trade Union, such as the Labourers) to account for the need to maintain an adequate level of labour resources to support trades work related to short-term projects, peak work volumes and intermittent work programs.

To execute planned work efficiently, the Distribution organization will continue to strategically balance staffing levels with the optimized use of overtime hours to manage demand. Overtime (OT) is utilized primarily to meet work requirements that bear a limited degree of predictability. Most overtime within the Distribution organization is classified as 'demand overtime' and is associated with customer demand and emergency work such as Trouble Calls, Storm damage, Equipment Replacement, Damage Claims and New Connections. This is distinct from 'planned overtime' which is the planned scheduling of additional work to meet project or work-related completion schedules while managing the size of the workforce or perform work outside of regular working hours to minimize outage impact to customers. For Distribution, demand overtime is necessary to address trouble calls, equipment failure, high priority defect corrections, and storm response. The Distribution work execution plan for the 2023-2027 period assumes OT usage will remain static at around 11%. These planning assumptions are based on an analysis of types of work that result in overtime hours as well as the average observed over the four year period prior to the filing of this application.

Workforce flexibility is a fundamental aspect of Distribution's resource model. Hydro One utilizes qualified vendors for staff augmentation purposes when it is recognized that a specific skill set required on a non-regular basis is not available internally or an influx of work such as supporting broadband internet access, or other customer driven demand work. This is necessary to ensure the efficient execution of the work program and address the ongoing variation in requirements for specific skills. As a result, Hydro One has continued to focus on its outsourcing strategy within the parameters of its existing collective agreements, specifically, through the use of Purchased Service Agreements (PSA) and Request for Proposals (RFP). By stipulating the business requirements and necessary skill set, Hydro One maintains control of the scope of work while driving price competition amongst proponents and increasing work program efficiency.

The Leamington TS DESN#2 Feeder Development project provides an example of the benefits that can be realized when outsourcing is utilized effectively. The sheer size of the project was unprecedented in the Distribution line of business with tight customer-driven timeline commitments. The magnitude of the underground cable build required was better suited to a specialized contractor with the experience and skillset required to perform the work. Distribution's internal workforce was then able to excel through the assignment of work best suited to their skills and expertise, and allowed for parallel construction of both overhead and underground feeders in order to meet project timelines. This resulted in the successful connection of 12 new feeders and approximately 200 MW of load to service new and existing customers.

The Canadian Radio-television and Telecommunications Commission's decision to declare broadband internet access as an essential service, followed by investments and incentives from Federal and Provincial governments for telecom companies provides an alternative example of how Hydro One chose to manage a portion of the influx of applications in 2020 by contracting out the construction of make-ready work in certain high demand locations.

3.10.4.2 MATERIAL SOURCING AND AVAILABILITY

Although the unpredictable nature of demand investments is largely accountable for variations in the plan, other factors include:

- material sourcing and availability;
- equipment and fleet accessibility;
- outage scheduling; and
- Site conditions.

Material costs account for 20% of capital expenditures and for this reason collaborative planning and strategic sourcing are fundamental components that support Distribution's work execution strategy. Delayed delivery of material can impact execution crews, outage plans, customers and costs. Hydro One has an increased focus on streamlining sourcing activities in order to drive improved value for the company. These initiatives ensure contracts are in place and long lead-time materials are being effectively managed to mitigate any potential impacts on program execution due to delays in availability of materials. Hydro One has also placed increased focus on supplier performance management to address any issues with delayed material delivery. This strategy will help manage the evolving sourcing needs of the business as is case with the Grid Modernization investments where Distribution continues to integrate modern technology into the capital work program. Prior to the use of new materials and equipment certain standards may need to be created or updated. This is an important factor to be considered during the planning of material sourcing and availability to ensure execution timelines can be met.

Hydro One's sourcing strategy also relies on a consolidated warehouse approach to coordinate the delivery of materials on scheduled delivery dates to service centers and station locations across the province. Materials are staged from a central warehouse and deployed when required at the work site. This approach ensures that execution receives the right materials at the right time and enables cost efficiencies to be realized by consolidating orders and freight. The warehouse also offers a kitted approach where all required materials for a specific project are bundled and kitted together to minimize job site preparation time and reduces the likelihood of misplaced materials. Alternatively, direct ship options are available if circumstances require expedited delivery or there is increased value based on storage and transportation logistics and costs. Recent technology and process enhancements that have been implemented within Supply Chain enable enhanced spending analytics, improve vendor management and allow for strategic and tactical sourcing to maximize value through negotiations, all of which play a key role in ensuring Distribution's material requirements are met (Exhibit C-09-04).

3.10.4.3 EQUIPMENT & FLEET ACCESSIBILITY

Identifying necessary equipment and fleet requirements to complete the various capital programs and projects must be incorporated into Distribution's tactical planning activities. Equipment and fleet costs account for approximately 10% of capital spend. Completing the annual program or project is put at risk if the appropriate equipment and fleet cannot be secured. During the planning process, Distribution takes into consideration the scope of work required, site conditions, access and seasonal factors to schedule appropriate equipment for safe and efficient execution.

As fleet and equipment is often shared across the organization, emphasis is placed on early release of work to provide sufficient time to plan and schedule. This is particularly true with regards to Mobile Unit Substation (MUS) availability, as Hydro One has a limited number of units that continue to be in high demand. Additionally, as alternate investment options to upgrade and modernize the system are explored, equipment and fleet needs continue to evolve. Recent investments where traditional fenced distribution stations have been replaced with padmount transformers provides an example where specialized equipment is required to transport and offload the transformer using a specialized crane that is not regularly used within Distribution. In circumstances like this, sufficient planning is critical to ensure equipment can be secured internally and if not available, external rental options are coordinated to meet project timelines.

3.10.4.4 OUTAGE SCHEDULING

Many of Hydro One's distribution projects and work programs require parts of the system to be electrically isolated while work is being performed. Obtaining the required planned outages becomes increasingly difficult as the distribution system grows and becomes more complex with the proliferation of Distributed Energy Resources (DER). Planned outages are also susceptible to being cancelled which can be attributed to storm activity, customer demands and system constraints. When planned outages are cancelled, crews have to be demobilized and work rescheduled for a future date. This can result in increased project costs and impact work accomplishments.

To minimize any inefficiency in outage coordination efforts due to these unforeseen issues, Hydro One has made a number of improvements to internal processes and increase communication with regard to outage planning and bundling of work. Some examples include coordination meetings to review work plans and required outages for large projects to improve coordination between controlling authorities and formally establish lead times for outage approvals. Coordination of lines project work with planned station outages has been a positive outcome as a result. Similarly, some program work such as pole replacement and defect correction work has been completed during outages planned for Worst Performing Feeder smart switch installations. This approach allows for improved utilization of system outages by increasing the total volume of work that can be executed during one outage as opposed to multiple outages throughout the year, subsequently reducing the overall impact to customers.

3.10.4.5 SITE CONDITIONS

Varying terrain and seasonal factors that differ across the province impact site conditions, resource needs in addition to equipment and material requirements. The upfront planning process takes into consideration the optimal season to complete work, urban and rural environments, on and off-road access points, required equipment and optimal crew size. Although these circumstances can be unpredictable and may require prompt reaction to changes, the organization utilizes certain conditions to take advantage of environmental conditions to complete work more efficiently.

There are situations where frozen conditions are ideal for access due to swamp-like environments or challenging access points that may be easier with use of snowmobiles. For example, during certain months of the year municipalities can impose what is referred to as half-load restrictions on select roads which prohibits the use of certain weight class of vehicles due to the risk of roadways being unstable for heavy loads. While the half-load season limits the window of certain work, Hydro One is able to make use of the roadways during frozen winter conditions to transport heavy equipment required for construction activities such as pole replacements. Another example of working in winter and frozen conditions involves construction activities in or near conservation parks where the risk of impacting wildlife habitats is minimal.

3.10.5 SAFETY

Hydro One is committed to “be the safest and most efficient utilities” through initiatives that drive operational performance in alignment with the organization’s values, vision and mission. As shown in Figure 1, Distribution has seen a reduction in recordable injury frequency, while serious injuries have fluctuated and remain an area of focus for the organization, with a plan to eliminate all serious injuries and fatalities by 2024.

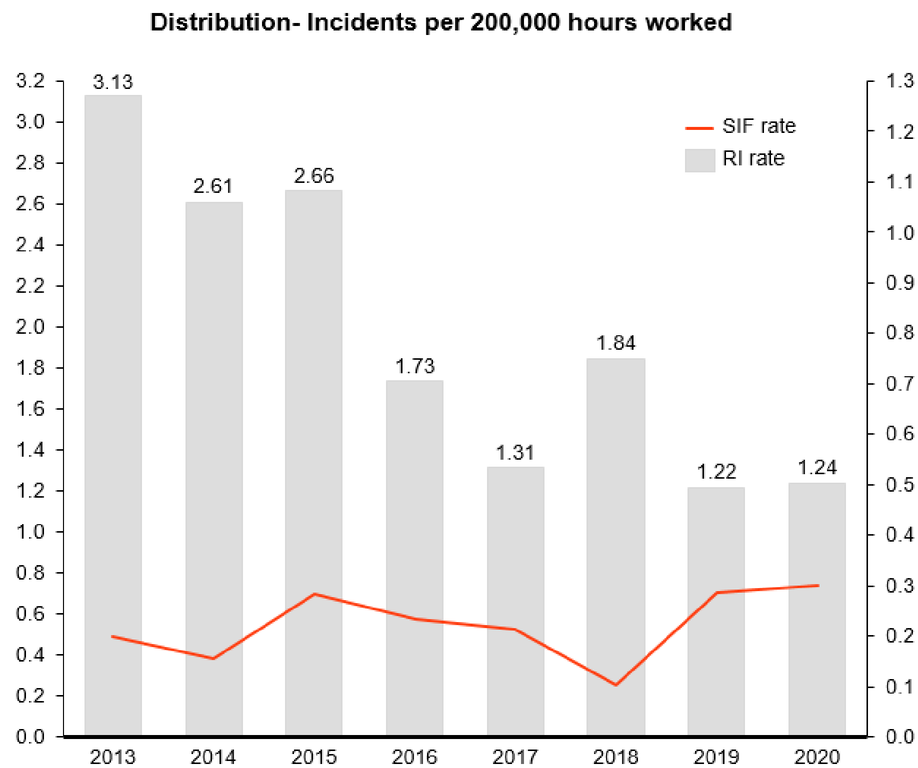

Figure 1: Capital Work Execution, Distribution – Serious Injury Frequency (SIF)

RECORDABLE INJURY AND SERIOUS INJURY RATE (PER 200,000 HOURS WORKED)

Hydro One believes that a safe utility is an efficient utility, and that a healthy safety culture fosters accountability and discipline across all aspects of the business. The newly established Chief Safety Officer (CSO) role in 2020 will lead the transformation of safety culture, and the Health Safety and Environment department was recently redesigned to provide a more effective focus on health and safety management systems, training and development, operations field support and learning, analytics and reporting. Furthermore, a Safety Improvement Team was created from a diverse cross section of the organization, including representatives from Distribution, to identify areas of improvement to prevent serious injuries and fatalities.

Hydro One is striving to transform and improve the safety culture through robust safety analytics and grass-roots employee engagement. The Safety Improvement Team has connected with more than 4,200 workers across the company, completed analysis of Hydro One's historical performance, and gathered safety best practices external to the organization. From this research, the team has outlined a plan to eliminate serious injuries and fatalities by 2024. This will be accomplished by addressing the root causes of safety issues, transforming the culture, and by embedding the right values, mindsets and behaviours.

In a healthy safety culture, there is a high-degree of accountability and engagement across every level of the organization. Hydro One employees reported just over 5,800 Near Misses and Safety Catches in 2020, which exceeds the annual target of 4,000. Going from 57 reported near misses in 2018 to 5,800 in 2020 demonstrates employee buy in and great adoption of the new mobile reporting tool, which work together to help establish a positive safety culture. The next phase will be to incorporate analytics and an ongoing feedback mechanism to drive continuous improvement.

Hydro One continues to improve workplace health and safety by ensuring effective job planning through its Human Success program. The overall goal of Human Success is to ensure the frontline workers and supervisors are well informed of potential risks, and are actively engaged in safe work planning. Weekly safety bulletins are distributed and shared with staff at the Monday morning tailboard sessions to ensure high-level planning discussions are relevant. Onsite planning meetings are carried out at the start of each day and after breaks to refocus staff and reinforce safe work practices. The use of open-ended questions is encouraged to generate good discussion and to ensure that everyone's viewpoints are heard. Crews also participate in warm-up/stretch sessions during the course of the day as needed to reduce the occurrence of soft tissue injuries.

Hydro One continues to deliver safety roll-outs to the field crews to reinforce the leadership's commitment to safety and ensure roles and responsibilities are communicated consistently. Safety roll-outs communicate the results from ongoing near miss / safety catch reporting and emphasize the importance of job planning in incident prevention and operational efficiency. Workplace Safety Observations are also being carried out by managers to ensure visible safety leadership presence in the field and ensure two-way communication is practiced through coaching and feedback; just over 5,300 Workplace Safety Observations were carried out in 2020.

3.10.6 PRODUCTIVITY AND CONTINUOUS IMPROVEMENT

3.10.6.1 PRODUCTIVITY

Hydro One continues to seek opportunities to improve process efficiencies that result in cost savings in the execution of its work programs as outlined in SPF Section 1.4. In support of the corporate productivity targets for the rate filing period, the Distribution Lines organization has initiated an efficiency improvement initiative known as Project Lighthouse. The objective of Lighthouse is to investigate, evaluate and implement efficiency opportunities within the Distribution Lines organization. Lighthouse is in the early stages of assessing certain efficiency improvement opportunities and their potential benefits to the organization. The focus of the project is to investigate opportunities that will improve planning and scheduling practices, streamline accountabilities and enhance processes, all with the objective of meeting the demands of a growing work program while meeting customer commitments. Central to this improvement initiative is the further development of skills and training of internal staff to enhance how work is planned, scheduled, monitored and executed. Lighthouse is an initiative that will support Distribution Lines in meeting Hydro One's productivity savings commitment however at this time, it is premature to determine the nature and degree to which the benefits will be realized by the organization.

The anticipated improvement opportunities expected from Project Lighthouse in regards to introducing upstream efficiencies to improve planning and schedule practices, technology use and coordination among work groups will benefit Distribution's work execution over the application period. As discussed in SPF Section 1.4, the goal of Hydro One's Productivity Framework is to effectively demonstrate continuous improvement in work execution and to achieve the applied productivity factors and supplemental stretch factor on capital for each of Hydro One Transmission and Hydro One Distribution. Hydro One anticipates that the areas described in this exhibit will contribute to identifying and realizing these productivity savings.

3.10.6.2 CONTINUOUS IMPROVEMENT

The organization has initiated significant improvements to equip its employees with modern tools to standardize Distribution designs and cost estimation. Full integration will provide enhanced usability, data accuracy, analytics and automation to increase productivity and improve the quality of customer service. New processes have also been adopted to ensure that project scopes are reviewed in advance of release which enables technical requirements, timelines and concerns to be identified upfront and adjustments made to the scope in advance of release. As a result, volume of re-designs is minimized and internal resource utilization is improved upon. This becomes even more critical when new equipment is introduced, as the development of new standards needs to be factored into project timelines to ensure designs are developed according to Hydro One's specifications. With the implementation of a technical solution that is consistent and enables flexibility, adapting to new work types and integrating new equipment will be streamlined and eliminate inefficient workarounds.

Hydro One continues to explore advanced technology options to improve reliability and drive efficiencies. Within the capital portfolio, the Distribution Modernization program is the primary vehicle for grid modernization, which will help minimize and restore power outages and reduce fault location time by distribution crews. This also includes continuing to leverage alternate outage options to execute capital programs and projects through the use of generators to minimize impacts to customers.

3.10.7 CONCLUSION

Distribution has developed a comprehensive strategy that demonstrates its ability to deliver a large and complex work portfolio within approved expenditure levels, while maintaining the necessary flexibility to adjust in a safe and effective manner. As demand investments continue to experience fluctuating volumes, the organization remains focused on improving its strategic and planning in the upfront process to drive downstream efficiencies while leveraging its flexible workforce to support the fluctuations. Maintaining robust oversight over the distribution work portfolio and continuing to identify efficient and cost-effective ways to execute work will remain at the forefront to ensure return on investments are maximized.

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SECTION 3.11 – DSP – MATERIAL INVESTMENT SUMMARY DOCUMENTS

3.11.1 INTRODUCTION

DSP Investment Summary Documents (ISD) are attached to this exhibit. ISDs are provided for any proposed capital expenditure within the DSP that exceeds a materiality threshold of $1M in a single year. For this rate application, ISDs for General Plant investments are detailed in GSP Section 4.11.

The list of material investments are provided in Table 1 and their associated Investment Summary Documents (ISD) are provided in the following sections.

Table 1 - Material DSP Investments ($M)

ISD	Investment Name	Forecasting Period				
		2023	2024	2025	2026	2027
System Access						
D-SA-01	Joint Use and Relocations	24.8	29.0	27.0	26.5	27.2
D-SA-02	New Load Connections, Upgrades, Cancellations	150.7	154.6	158.5	162.5	166.7
D-SA-03	Connecting Distributed Energy Resources	1.4	1.4	1.4	1.4	1.4
D-SA-04	Metering Sustainment	62.6	55.6	40.1	22.2	8.9
System Access Projects and Programs Less Than Materiality Threshold		0.0	0.0	0.0	0.0	0.0
Total System Access		**239.6**	**240.6**	**227.0**	**212.6**	**204.3**
System Renewal						
D-SR-01	Distribution Stations Demand Capital Program	6.2	6.3	6.4	6.5	6.7
D-SR-02	Mobile Unit Substation Program	3.5	4.2	2.9	3.3	4.6
D-SR-03	Distribution Station Planned Component Replacement Program	4.6	3.3	1.1	1.2	1.2
D-SR-04	Distribution Station Refurbishment	44.8	41.5	28.5	32.3	32.1
D-SR-05	Distribution Lines Trouble	106.0	108.1	110.3	112.5	114.7

ISD	Investment Name	Forecasting Period				
		2023	**2024**	**2025**	**2026**	**2027**
	Call and Storm Damage Response Program					
D-SR-06	Distribution Lines PCB Equipment Replacement Program	9.4	9.5	9.5	0.0	0.0
D-SR-07	Pole Sustainment Program	107.9	110.6	112.4	114.9	116.8
D-SR-08	Distribution Lines Minor Component Replacement Program	12.4	14.5	13.5	8.6	7.1
D-SR-09	Submarine Cable Replacement Program	12.2	12.5	12.7	13.0	13.2
D-SR-10	Distribution Lines Sustainment Initiatives	31.5	30.3	35.3	43.2	42.7
D-SR-11	Life Cycle Optimization & Operational Efficiency Projects	2.8	6.5	7.1	0.8	0.4
D-SR-12	Advanced Meter Infrastructure 2.0 (AMI 2.0)	30.9	62.0	153.7	154.4	157.3
System Renewal Projects and Programs Less Than Materiality Threshold		0.9	0.9	0.9	0.9	0.9
Total System Renewal		**373.1**	**410.3**	**494.2**	**491.5**	**497.8**
System Service						
D-SS-01	System Upgrades Driven by Load Growth	98.2	76.3	127.5	76.1	100.2
D-SS-02	Reliability Improvements	7.3	0.1	6.5	18.6	7.5
D-SS-03	Demand Investments	13.2	13.4	13.7	13.9	14.2
D-SS-04	Energy Storage Solutions	34.3	35.0	35.6	36.3	36.0
D-SS-05	Worst Performing Feeders	39.6	40.9	42.2	43.0	43.8
D-SS-06	Power Quality and Stray Voltage	3.8	3.9	4.0	4.0	4.1
System Service Projects and Programs Less Than Materiality Threshold		0.1	0.1	0.1	0.1	0.1
Total System Service		**196.5**	**169.7**	**229.6**	**192.0**	**205.9**

D-SA-01	**JOINT USE AND RELOCATIONS**
Primary Trigger:	Mandated Obligations
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	24.8	29.0	27.0	26.5	27.2	134.6

Summary:

This investment involves the rearrangement, relocation, and/or the replacement of poles as required to accommodate joint use partners' attachments or due to siting conflicts with work by Road Authorities, railways and private land owners. The primary trigger of this investment is compliance with regulatory and statutory obligations under Hydro One's Distribution Licence and the *Public Service Works on Highways Act*, respectively. The investment is expected to ensure ongoing compliance with these requirements, and create mutual benefit to Hydro One and third party proponents to support infrastructure development, generate external revenue, and realize cost sharing opportunities where applicable.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

The investments in this ISD consist of two programs: Joint Use and Relocations. The purpose of these investments is to modify or upgrade distribution system facilities to accommodate the requirements of joint use partners such as third party telecommunication providers who occupy Hydro One assets, or to relocate facilities at the request of Road Authorities and private land owners.

The main driver of the Joint Use program is to provide joint use partners with access to Hydro One's support structure network. Revenue generated through joint use is reflected in Hydro One's distribution external revenues (Exhibit D-02-02). Joint use partners' access to Hydro One assets is subject to Joint Use agreements between the parties and Hydro One, consistent with the provisions included in Hydro One's distribution licence related to telecommunication attachments. These joint use capital expenditures reflect costs of "make ready" investments that are necessary for third parties to initially attach their equipment to Hydro One's support structures. Joint Use partners are responsible for all applicable costs as related to their request.

The main driver of the Relocation program is Hydro One's obligation to perform line relocation work at the request of municipal and provincial Road Authorities as per the requirements of the *Public Service Work on Highways Act* (PSWHA) and associated Ministry of Transportation guidelines, and line relocation work requested by customers and third parties in accordance with Hydro One's Conditions of Service and what is allowable based on the distribution system code. These capital expenditures are required to complete relocation work as requested by the party driving the work in order to facilitate the development of the property or the changing needs of the Road Authority, where known adverse impacts to Hydro One plant have been identified. The applicable costs would be charged to the party requesting the work as defined in the PSWHA or in Hydro One's Conditions of Service as appropriate.

The Joint Use and Relocations programs are driven by customer demand and thus must be accommodated within Hydro One's work program.

B. INVESTMENT DESCRIPTION

The necessary investments in Joint Use and Relocations vary year-over-year based on external third party and customer demand.

JOINT USE

Joint use investments modify or upgrade Hydro One distribution line equipment in order to accommodate the use of this equipment by third party joint use partners. These partners may include telecommunication companies (communication circuits), municipalities (street lighting - safety), local distribution companies, or generators connected to the distribution system.

The scope of the required modifications or upgrades may involve increasing pole class to accommodate changes in pole loading, and/or increasing pole height to obtain appropriate ground clearances for public safety. These activities may also carry the cost associated with premature retirement of in-service assets.

Over the 2023-2027 period, Hydro One expects to invest $66.4M in the Joint Use program.

LINE RELOCATIONS

Line relocation investments alter the location of Hydro One distribution line equipment in response to road modifications initiated by Road Authorities or in response to property development initiated by individual customer requests.

Hydro One occupies road allowances at no cost. However in return, Hydro One is required, on occasion, to install, relocate or reconstruct its facilities in order to accommodate specific Road Authority or property development requirements. Most commonly, this involves relocating lines to accommodate changes to roads, highways, and bridges. The cost of the plant relocation is either fully or partially recoverable, depending on the specific circumstances of each investment as defined by the PSWHA.

For relocations on other lands, including railway and public lands, Hydro One is required, on occasion, to rearrange, reconstruct or relocate its facilities in order to accommodate other developments that are known to have adverse impacts on the existing Hydro One plant. Hydro One will then recover, from the third party requesting the work, all applicable costs based on existing permissions or rights-of-way.

Over the 2023-2027 period, Hydro One expects to invest $68.2M in the Relocations program.

C. OUTCOMES

C.1 OEB RRF OUTCOMES

Investments made under the Joint Use program align with the Renewed Regulatory Framework (RRF) Public Policy Responsiveness outcome, as they will result in Hydro One being able to continue servicing Joint Use requests pursuant to our Joint Use agreements and to maintain compliance with the company’s distribution licence. The principle of Hydro One’s Joint Use program is to work for the mutual benefit of Hydro One’s customers and the customers of the Joint Use partners. Further, the Joint Use program reduces duplicate pole infrastructure and allows for cost sharing between Hydro One and Joint Use partners.

The Relocations program also supports Public Policy Responsiveness outcomes, which address legislative requirements under the PSWHA.

The following table presents anticipated benefits as a result of the investment in accordance with the RRF:

Table 1 - Outcome Summary

Customer Focus	• Realize mutual benefits of Hydro One infrastructure for rate payers, while completing work to meet the interests and objectives of joint use partners, Municipal Road Authorities and other parties.
Public Policy Responsiveness	• Comply with Section 22.1 Hydro One's Electricity Distribution Licence for access to distribution poles by our joint use partners. • Comply with legal obligations regarding asset relocations under the PWHSA, Hydro One's Conditions of Service and the Distribution System Code.
Financial Performance	• Support the installation of new attachments by joint use partners that may result in increased External Revenue which will offset the rates revenue requirement. • Realize cost savings by cost sharing, where possible, on upgrades or renewal of the distribution system in response to Road Authority, joint use partners or customer requests.

D. EXPENDITURE PLAN

Planned expenditures for the 2023-2027 period are based on historical spending in the Joint Use and Relocations programs, adjusted to reflect forecast work volumes provided by Joint Use partners, based on available information at the time of plan development. External factors such as the planned expansion of telecommunications infrastructure, driven by some of our Joint Use partners, and internal factors such as the integrated work volumes of acquired utilities are reflected in the anticipated increase of forecast work volumes as compared to the historical period. Year-over-year variations in expenditures are generally due to the expected volume and scope of Joint Use and Relocation requests.

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	54.4	64.8	59.7	58.5	60.4	297.8
Less Removals	6.5	7.8	7.2	7.0	7.2	35.7
Capital and Minor Fixed Assets	**47.9**	**57.0**	**52.5**	**51.5**	**53.2**	**262.1**
Less Capital Contributions	23.1	28.0	25.5	25.0	26.0	127.6
Net Investment Cost	**24.8**	**29.0**	**27.0**	**26.5**	**27.2**	**134.6**

The forecast investments related to Joint Use over the planning period reflects peak in activity in 2024, followed by a decrease in 2025, after which anticipated volumes remain relatively stable in 2026-2027.[1]

Hydro One expects that demand for relocation requests will continue at historic levels since municipalities continue to expand at a relatively similar rate. Road Authorities require any existing infrastructure to be relocated so as to provide for these expansions. While year-over-year expenditures may vary due to the large, multi-year nature of many road expansion projects, Hydro One expects that aggregate expenditures over the 2023-2027 period will be consistent with historic levels.

E. ALTERNATIVES

This investment is non-discretionary. No alternatives are considered, because Hydro One would not be compliant with its distribution licence if it did not proceed to service these joint use requests. Similarly, Hydro One has statutory obligations under the PSWHA to perform requested relocations by Road Authorities.

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[1] Volumes and capital costs do not reflect potential volume changes that may arise from the new *Supporting Broadband and Infrastructure Expansion Act,* which is not anticipated to be funded by ratepayers.

F. EXECUTION RISK AND MITIGATION

Hydro One's forecast is based on historic and future volumes of joint use attachments identified by Joint Use partners. To the extent that volumes exceed the forecast due to new legislation or other factors, Hydro One will assess appropriate options to accommodate requests from Joint Use partners.

For the relocation portion of investment requests, Hydro One's forecast is based on historic and known future volumes. Hydro One works with third parties to identify future relocation requests with sufficient lead-time to plan and execute work without affecting other investments.

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D-SA-02	NEW LOAD CONNECTIONS, UPGRADES, CANCELLATIONS
Primary Trigger:	Customer Requests
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	150.7	154.6	158.5	162.5	166.7	793.0

Summary:

This investment involves the connection of new load customers to the distribution system, the upgrade of services for existing load customers, and cancelling existing services upon customer request as required to comply with statutory, regulatory and licence obligations. The primary trigger of the investment is customer service requests. The investment is expected to meet Hydro One's obligations to connect, upgrade, and cancel the services of requesting load customers.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One is obligated to connect new customers to the distribution network, upgrade services where required to meet the needs of existing customers, and cancel existing services upon customer request. The investments in the New Load Connections, Upgrades and Cancellations program will allow Hydro One to meet the new and increased electrical needs of load customers, including a forecast of approximately 91,700 new connections, 22,800 service upgrades and 25,700 service cancellations over the 2023-2027 period. These investments include the activities described below.

Pursuant to Hydro One's compliance responsibilities and commitments under the *Electricity Act, 1998,* Distribution System Code (DSC) and its distribution licence and conditions of service Hydro One is required to fulfill requests for connections or make an offer to connect all distribution customers in its service area on a non-discriminatory basis, upon written request for connection. A new connection normally requires the preparation of a service layout and installation of secondary service conductor and metering. A new connection may also require the installation or replacement of a service transformer, secondary bus or support structure, or modification or addition to the main distribution system. New connection work is divided into three major categories for forecasting: (1) non-subdivision new connections, (2) subdivisions, and (3) non-subdivision large expansions (single phase expansion projects greater than 1 km, or three phase expansion projects greater than 0.5 km).

Service Upgrades are upgrades of existing load connections in response to customer requests. A service upgrade normally requires the preparation of a service layout and replacement of secondary service conductors. A service upgrade may also require the replacement of the service transformer, secondary bus or metering, or modification of or addition to the main distribution system. Service upgrade work is divided into two major categories for forecasting: (1) service upgrades, and (2) large expansions (three phase expansion projects greater than 0.5 km).

For cancellations of existing service, Hydro One removes idle connection assets (such as transformers, wires and meters). Service cancellations happen in response to customer requests and for vacant premises.

Customer connections and upgrades are primarily driven by ongoing growth in residential, industrial and commercial load in different parts of Hydro One's distribution territory. Hydro One forecasts the following new connection, service upgrade and service cancellation volumes in the 2023-2027 period:

Table 1 – New Connection, Service Upgrade and Service Cancellation Volumes

Description	2023	2024	2025	2026	2027
New Connections	18,130	18,230	18,330	18,430	18,540
Service Upgrades	4,500	4,530	4,550	4,580	4,600
Service Cancellations	5,130	5,130	5,130	5,130	5,130

The new connection and service upgrade volume forecasts are based on historic volumes and the forecasting methodology described in Exhibit D-05-01.

Over the 2018-2020 period Hydro One made an average of 17,579 new connections and 4,431 service upgrades per year. This includes an average of 9,342 non-subdivision connections, 8,226 subdivision connections, and 15 non-subdivision large expansion projects per year. Hydro One expects similar numbers of connections and upgrades over the 2023-2027 period, as shown in Figures 1 and 2 below.

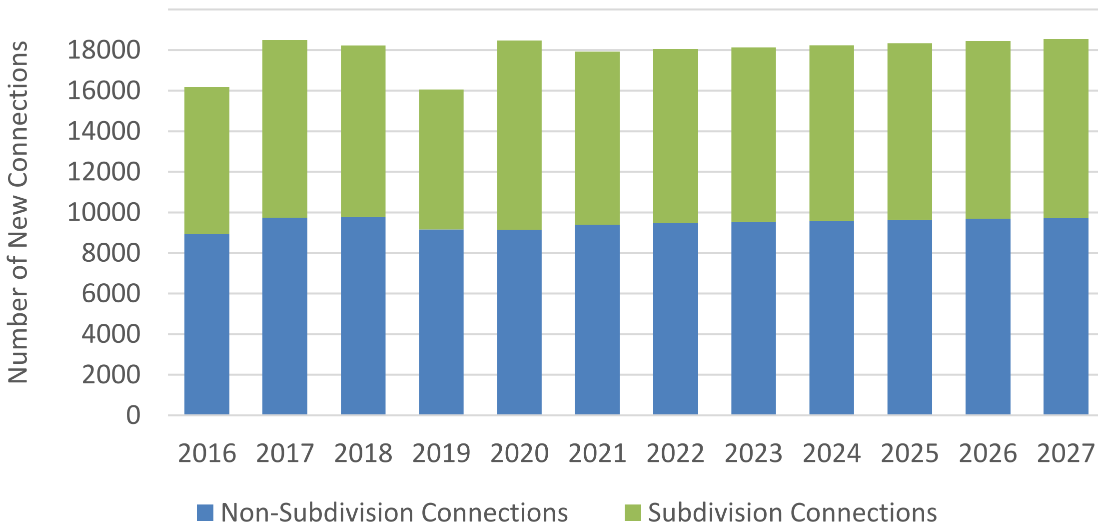

Figure 1: New Connection Volumes[1]

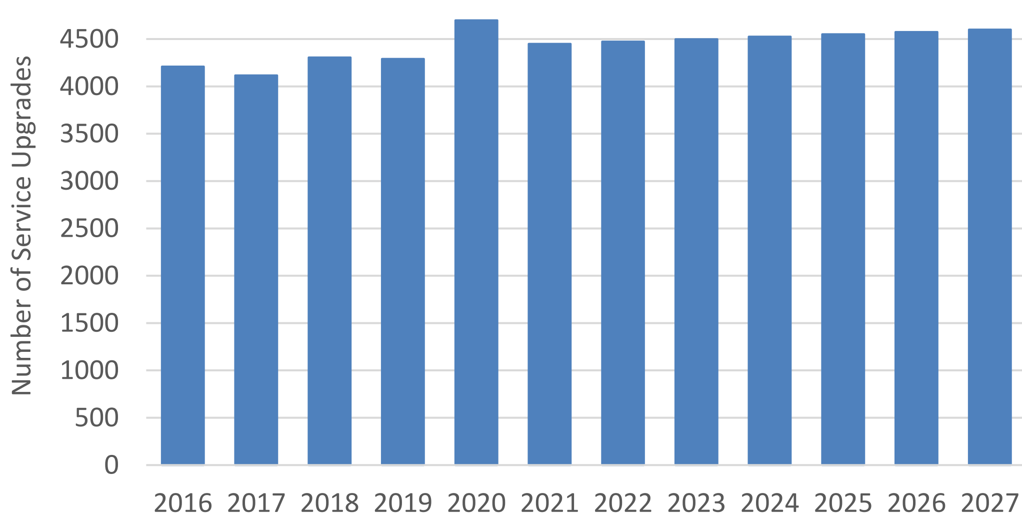

Figure 2: Service Upgrade Volumes[2]

[1] 2016-2020 volumes are actual, 2021-2027 volumes are forecast.
[2] 2016-2020 volumes are actual, 2021-2027 volumes are forecast.

The service cancellation volume forecast is based on 2011 to 2017 average volumes. The service cancellation volume forecast is not based on more recent years due to disruption caused by Hydro One's extension of the 2018 winter disconnection moratorium to mid-August 2018, and the 2020 pandemic disconnection moratorium. Cancellation of services to vacant premises was not performed during the 2018-2020 period due to these circumstances, but is expected to return to pre-2018 levels for the forecast period.

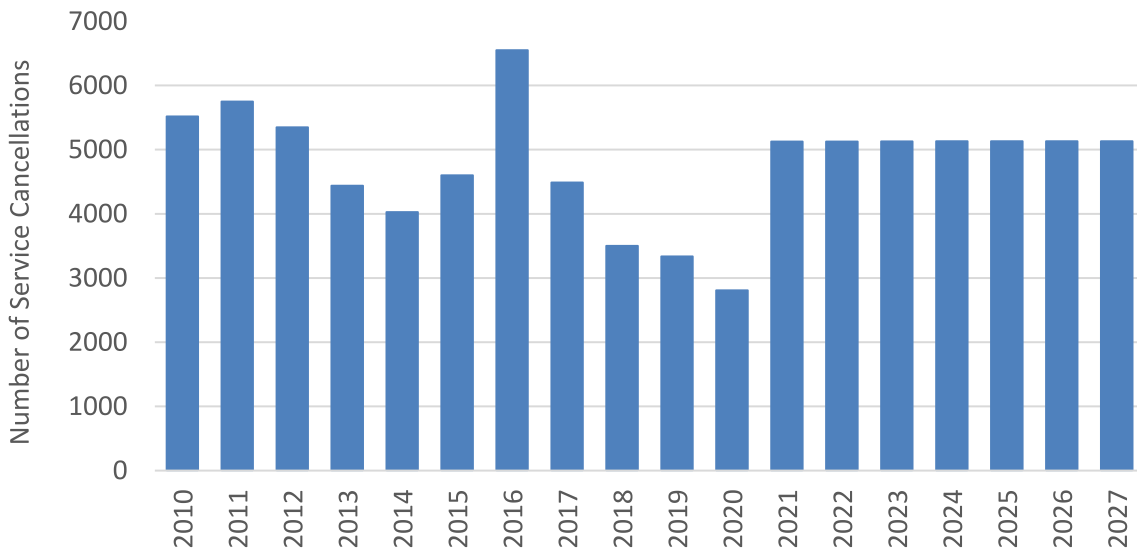

Figure 3: Service Cancellation Volumes[3]

B. INVESTMENT DESCRIPTION

Investments for New Load Connections, Upgrades and Cancellations are required to fund the design and construction activities associated with customer connections and removals.

[3] 2010-2020 volumes are actual, 2021-2027 volumes are forecast.

NEW CONNECTIONS

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One is required to provide a connection service to new industrial, commercial and residential customers when requested. Work to provide a new connection may include, as required: performing distribution system impact assessments to ensure the system is sufficient to accommodate the connection without negative impacts on the new or existing customers and identifying necessary system modifications, providing high-level initial cost estimates to the customer, detailed design of the connection and expansion, obtaining easements and municipal consent to construct new facilities, performing economic evaluations, preparing offers to connect, and constructing and commissioning the necessary facilities. The division of costs between Hydro One and the customer is determined based on the company's connection policies, which are in accordance with the DSC requirements. A basic connection consisting of a service layout, overhead transformation, 30 meters of overhead conductor (for residential only), and standard retail metering, is provided free of charge to new customers that lie along the existing network, as per the DSC requirements. For customers that require expansion of the network in order to be connected, a discounted cash flow calculation is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection and system expansion. Customer contributions from requesting customers towards new connections for system expansions and costs beyond the basic connection are estimated to be between $27.9M and $30.7M per year during the 2023 to 2027 period.

The net and gross capital expenditure forecast for non-subdivision and subdivision new connections are based on 2018-2020 average net and gross actual cost per unit (adjusted for inflation) and forecast volumes. The large expansion project component of the new connections program is forecast based on the 2016-2020 average net and gross cost adjusted for inflation. A longer time horizon was used for large expansion projects due to the high variability of annual costs for these projects. Forecast customer capital contribution is calculated as the difference between the gross and net capital expenditures, less removals.

SERVICE UPGRADES

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One is required to respond to existing customers who require a larger service to accommodate additional load and/or modify their electrical service entrance. Work to provide a service upgrade may include, as required: performing distribution system impact assessments to ensure the system is sufficient to accommodate the connection without negative impacts on the existing customers and identifying necessary system modifications, providing high-level initial cost estimates to the customer, detailed design of the connection and expansion, obtaining easements and municipal consent to construct new facilities, performing economic evaluations, preparing offers to connect, and constructing and commissioning the necessary facilities. A service upgrade typically requires the replacement of secondary service wires and the preparation of a service design. It may also be necessary to upgrade transformer(s), replace meters or install additional transformers. For standard service upgrades, Hydro One will provide a service layout, pole-mounted transformer, and the meter installation, if required. Costs for service modifications beyond the standard service upgrade are recovered from the customer. Hydro One's customer capital contribution policies adhere to DSC requirements. Customer contributions from requesting customers towards service upgrades for system expansions and costs beyond the basic connection are forecasted to be between $10.6M and $11.6M per year over the 2023 to 2027 period.

The net and gross capital expenditure forecast for service upgrades is determined based on 2018-2020 average net and gross actual cost per unit (adjusted for inflation) and forecast volumes. The large expansion project component of the service upgrade program is forecast based on the 2016-2020 average net and gross cost adjusted for inflation. A longer time horizon was used for large expansion projects due to the high variability of annual costs for these projects. Forecast customer capital contribution is calculated as the difference between the gross and net capital expenditures, less removals.

SERVICE CANCELLATIONS

Service cancellations involve customer requests for permanent disconnection from the distribution system, or connection assets that are unused for a prolonged period of time (vacant premises). Hydro One removes idle assets, such as transformers, poles, service wires and meters for safety and security reasons. As this work involves the removal of Hydro One owned equipment, these costs are accounted for under depreciation and are not capitalized. Service cancellations are included in this program's "Removals" costs in the cost table in this document.

The gross capital expenditure forecast for service cancellations is based on historic unit costs.

C. OUTCOMES

This investment will meet Hydro One's licence obligations to connect requesting load customers and accommodate the upgrade of existing load connections. It will also meet the need to cancel the services of requesting customers, including the removal of idle connection assets.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 2 - Outcome Summary

Customer Focus	• Fulfill customer requests for connections and upgrades within established time frames to ensure customer satisfaction.
Operational Effectiveness	• Ensure all new connections or upgrades meet latest standards. • Remove assets when services are cancelled to mitigate safety risks.
Public Policy Responsiveness	• Comply with Section 28 of the Electricity Act, 1998, and Section 7 of Hydro One's Distribution Licence to provide new connections or service upgrades when requested by customers.

D. EXPENDITURE PLAN

Planned costs for the program are based on historic actual costs and a forecast of future request volumes. The actual program costs will be comprised of the individual connections, upgrades, and service cancellations completed on an annual basis. The main factors impacting the program cost are the number of requests received and the amount of main system and connection asset work required to accommodate the requests. The forecast capital contribution from requesting customers is approximately 20% of gross investment cost and is consistent with historic actuals.

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	200.5	205.5	210.7	216.0	221.4	1,054.0
Less Removals	11.3	11.6	11.8	12.1	12.4	59.2
Capital and Minor Fixed Assets	**189.2**	**194.0**	**198.9**	**203.9**	**209.0**	**994.8**
Less Capital Contributions	38.5	39.4	40.3	41.3	42.3	201.9
Net Investment Cost	**150.7**	**154.6**	**158.5**	**162.5**	**166.7**	**793.0**

E. ALTERNATIVES

No alternatives are considered. Not proceeding with these investments would result in non-compliance with Hydro One's obligations under its distribution license requirements and the DSC. This work is a regulatory requirement.

F. EXECUTION RISK AND MITIGATION

Hydro One successfully connects several thousand load customers to its distribution system every year, and therefore does not anticipate any major risks to this program.

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D-SA-03	**CUSTOMER DEMAND DISTRIBUTED ENERGY RESOURCES**
Primary Trigger:	Customer Requests
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
Net Cost	1.4	1.4	1.4	1.4	1.4	7.1

Summary:

This investment involves funding for modifications to the distribution system required to connect new Distributed Energy Resource (DER) facilities. The funding will continue to enable the connection of renewable energy projects under various programs. The connection of DER is integral to meet the energy demands of the province, as well as to support reducing peak demand. The primary trigger of the investment is customer service requests. The investment is expected to meet Hydro One's distribution license obligations to connect DER that meet the requirements of Distribution System Code.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

The Distribution System Code (DSC) and Hydro One's distribution license obligate it to connect Distributed Energy Resources (DER) that meet the requirements of the DSC. The connection of DER to Hydro One's distribution system has added a significant amount of renewable energy in Ontario under different IESO programs and the Ontario Net Metering program.

DER activity in Ontario has shifted from retail generators participating in historical IESO procurement programs to behind-the-meter (BTM) load displacement generators participating in the IESO's Industrial Conservation Initiative (ICI) program and the Ontario Net Metering program. Previously, the dominant source of renewable DER applications had been the Feed-in Tariff (FIT) program which was terminated in 2017. The Net Metering program is still limited to renewable DER, and remains active and regulated by Ontario Regulation 541/05 (O. Reg. 541/05).

The IESO ICI program allows large distribution connected load customers to reduce their Global Adjustment cost by reducing their contributions to peak electricity use during the top five Ontario peak hours. The majority of these projects are non-renewable and range in size from 500 kW to 20 MW depending on size of the load facility. Since 2018, the DER applications received by Hydro One have been primarily combined heat and power/co-generation, natural gas, diesel and battery energy storage systems (BESS). The cost for connecting these non-renewable energy projects to Hydro One distribution system is 100% recoverable from the DER customers. Currently, Hydro One is receiving a moderate number of DER applications under the IESO ICI program.

The only active renewable energy program in place in the province of Ontario is the Net Metering program, which is regulated by O. Reg. 541/05. The Net Metering program provides opportunities to all types of customers including residential, commercial and industrial to reduce their bills by offsetting their energy costs through renewable generation. Based on these two programs, the number of projects forecast for 2021 to 2027 is shown in Table 1.

Table 1 - DER Forecast for 2021-2027

		Forecast Number						
Year		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Non Renewable Energy Projects	**> 10 kW**	20	15	15	15	15	15	15
	≤ 10 kW	5	5	5	5	5	5	5
Renewable Energy Projects	**> 10 kW**	60	50	50	50	50	50	50
	≤ 10 kW	150	150	150	150	150	150	150

This customer DER forecast is based on historical numbers and other available information on current active DER programs. For the purposes of this forecast Hydro One has only accounted for existing DER programs.

B. INVESTMENT DESCRIPTION

The investments in this ISD modify and, as necessary, upgrade Hydro One’s Distribution System to connect new DER. These upgrades are necessary to prevent equipment damage and preserve power quality to existing load customers. DER customers make capital contributions to the connection work in accordance with Hydro One's connection policy and the cost allocation as required by the DSC. The required funding in excess of these contributions is provided by Hydro One. Hydro One continues to apply the DSC rules related to renewable energy projects by funding a portion of the expansion cost (up to $90,000/MW) and 100% of Renewable Enabling Improvement (REI) investments. The costs for non-renewable energy projects are 100% recoverable from the DER customers.

The investments in this program are managed on a project basis. Each DER project involves estimating, design, labour, material and the costs associated with its physical connection to Hydro One distribution system. The typical scope of work required to enable the connection of DER to Hydro One’s distribution system includes but not limited to the following:

- the connection of the customer's tap line to Hydro One distribution system;
- building of new line expansions or upgrade of the existing line conductor;
- revenue metering upgrades;
- upgrades to monitoring, protection, and control system;
- upgrades of in-line reclosers or station reclosers;
- addition of new voltage regulators; and
- upgrades to the existing line voltage regulator controls.

C. OUTCOMES

This investment will provide the required connection of DERs throughout Hydro One territory without compromising system reliability by maintaining power quality, proper protection and loading capability of the distribution assets.

C.1 OEB RRF OUTCOMES

The following table 2 presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcome Summary

Customer Focus	• Maintain customer satisfaction by connecting new DER within contractually established timeframe.
Operational Effectiveness	• Ensure that all upgrades are made to the latest Hydro One standards to maintain reliability of the distribution system.
Public Policy Responsiveness	• Comply with the requirements of DSC Section 6.2.4 and Hydro One's Electricity Distribution Licence to connect qualifying DER. • Enable the connection of renewable energy projects in the Province of Ontario under various programs.

D. EXPENDITURE PLAN

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	4.7	4.7	4.7	4.7	4.7	23.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**23.5**
Less Capital Contributions	3.3	3.3	3.3	3.3	3.3	16.5
Net Investment Cost	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**7.1**

The investment forecast provided in Table 3 is based on historical spend and current active DER programs.

E. ALTERNATIVES

This is a demand-based program for connecting new DER to Hydro One's distribution system. No alternatives are considered, as not proceeding with these investments would result in non-compliance with the requirements of Hydro One's distribution license and the DSC. This work is required to satisfy regulatory requirements.

F. EXECUTION RISK AND MITIGATION

Hydro One connects a significant number of DER to its distribution system every year on demand. No major execution risk is expected. However, there is potential for normal project risks that may affect the specific timing of individual projects, such as outage availability, volume of requests, weather, materials availability and other such variables.

These risks are mitigated by working with customers to set a schedule that aligns with outage availability. The DER projects are prioritized in order to meet the required service obligations. This prioritization and timing is completed through scheduling of work. Hydro One also maintains communications with the customer to ensure that all requirements are met so the parties can complete their connection by the agreed upon in-service date.

D-SA-04	METERING SUSTAINMENT
Primary Trigger:	Mandated Service Obligation
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	62.6	55.6	40.1	22.2	8.9	189.5

Summary:

This investment involves the maintenance of Wholesale and Retail Revenue Meter Installations, with the primary trigger being meeting regulatory requirements. Wholesale Meter compliance segment involves the maintenance of Wholesale Revenue Meter Installations (WRMIs) while the Retail Revenue Meter compliance segment primarily involves the maintenance of Hydro One's Advanced Metering Infrastructure (AMI 1.0) system. Hydro One currently owns, operates, and maintains approximately 1.4 million retail revenue metering devices and 422 wholesale meter installations. This sustainment investment ensures Hydro One has sufficient meter inventory and resources to replace failed retail and wholesale meter installations in a timely manner for reliable customer billing; to perform required sampling and reverification programs; and to perform necessary upgrades and replacement of failing metering equipment to meet regulatory requirements. The AMI 1.0 system is experiencing increasing failure rates and is reaching its end of life. These investments address the increasing AMI 1.0 failure rates to maintain the existing infrastructure while its replacement program, AMI 2.0, is executed.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

The metering sustainment program funds investments in Hydro One's metering technology to ensure the reliable measurement of electricity for customers. The program consists of two segments: Wholesale Revenue Meter compliance and Retail Revenue Metering Compliance. The Wholesale Meter compliance segment involves the maintenance of Wholesale Revenue Meter Installations (WRMIs). The Retail Revenue Meter compliance segment primarily involves the maintenance of Hydro One's Advanced Metering Infrastructure (AMI 1.0) system. Hydro One currently owns, operates, and maintains approximately 1.4 million retail revenue metering devices and 422 wholesale meter installations. This sustainment investment ensures Hydro One has sufficient meter inventory and resources to replace failed retail and wholesale meter installations in a timely manner for reliable customer billing; to perform required sampling and reverification programs; and to perform necessary upgrades and replacement of failing metering equipment to meet regulatory requirements.

This investment is primarily driven by regulatory compliance requirements including:

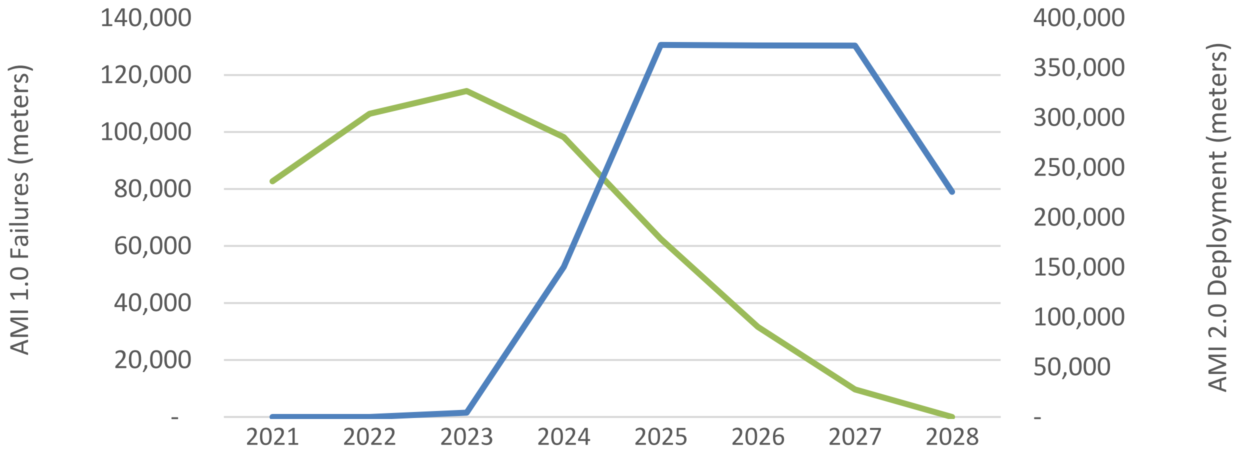
- Measurement Canada's *Electricity Gas and Inspection Act* (R.S.C., 1985, c. E-4) and related regulations setting out requirements that meters be resealed at specified intervals to ensure meter accuracy. Once a seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended via compliance testing, or be replaced. In addition, the act sets out obligations for ensuring good repair of equipment.
- Measurement Canada's *Weights and Measures Act* (R.S.C., 1985, c. W-6) and related regulations setting out requirements for the approval and certification of meters, and related regulations requiring devices be maintained in proper operating condition.
- Ontario Energy Board's *Distribution System Code* (March 2020), setting out regulatory service standards requiring distributors to issue no more than two estimated bills every 12 months and to issue an accurate bill to customers at least 98% of the time;

- Ontario Energy Board's *Standard Supply Code for Electricity Distributors* (Oct. 13, 2020), setting out customer billing requirements;[1] and
- IESO *Market Rules for the Ontario Electricity Market* (Feb. 26, 2021), Chapter 6, Wholesale Metering, setting out requirements for wholesale metering installations.

Meter failures occur for a number of reasons (e.g., reaching the end of their service life, storm damage, vandalism, fire damage, manufacturer defects, etc.) and their replacement is critical to ensure reliable and accurate billing in accordance with regulatory requirements.

The key driver of the level of investment for the metering sustainment program in the filing period is the need to replace failing AMI 1.0 meters that are reaching end of life (see DSP Section 3.2 and D-SR-12). The number of AMI 1.0 meter failures over the filing period is a function of: 1) AMI 1.0 meter failures; and 2) the pace of replacement of AMI 1.0 meters with AMI 2.0 meters (see D- SR-12). Figure 1 below illustrates the projected number of failed AMI 1.0 meters (the green line) in relation to the planned replacement of AMI 1.0 meters with AMI 2.0 meters (the blue line), illustrating declining AMI 1.0 failures as AMI 2.0 meters are installed.

[1] The OEB adopted amendments to the Standard Supply Service Code that came into effect on October 13, 2020 enabling electricity consumers on the Regulated Price Plan (RPP) to opt out of time-of-use prices and to elect instead to be charged on the basis of tiered pricing. These changes, while enabling customer choice in customer pricing options, has no impact on meter functionality or requirements as meters must continue to measure and communicate usage data for both pricing options.



	2021	2022	2023	2024	2025	2026	2027	2028
AMI-1 Failures	82,705	106,387	114,383	98,206	62,495	31,617	9,659	-
AMI-2 Deployment	-	-	4,335	150,438	373,010	372,474	372,269	225,703

Figure 1: AMI 1.0 Failures vs AMI 2.0 Deployment

The number of AMI 1.0 failures (the green line) is based on a blended failure rate consisting of: 1) GEN 1 meter failure rates (the vendor's first AMI 1.0 meter design installed in the 2007-2009 period) based on Accelerated Life Testing Study results[2]; and 2) failure rates of all other meters (the vendor's subsequent meter designs installed in the post 2009 period) based on historical failure rates assumed to remain constant over the test period. The planned deployment of AMI 2.0 meters (blue line) is based on the five-year pacing proposed in D-SR-12.

Hydro One must also perform meter sampling and reverification programs in accordance with Measurement Canada regulatory requirements. Measurement Canada has jurisdiction over the administration and enforcement of the *Weights and Measures Act* and *Electricity Gas and Inspection Act*. These acts govern Hydro One's ability to bill its customers for electricity usage, and require all meters be resealed at pre-determined intervals to ensure electricity use is metered accurately. Once a seal expires, the meter cannot be used for billing purposes and must either have its seal period extended (via compliance testing), or be replaced. For homogeneous meter batches, Measurement Canada allows a sampling protocol to verify meter accuracy. If the statistical accuracy from sample testing is within required levels, all the meters in the sample

[2] See D-SR-12, pgs. 7-8, for discussion of Accelerated Life Testing Study results.

batch receive a seal extension. Certain meters need to be re-verified and tested individually because they to not fit within the sampling program and are required to be removed for testing and replaced with new meters. Figure 2 below provides the meter inventory required for sampling and re-verification purposes.

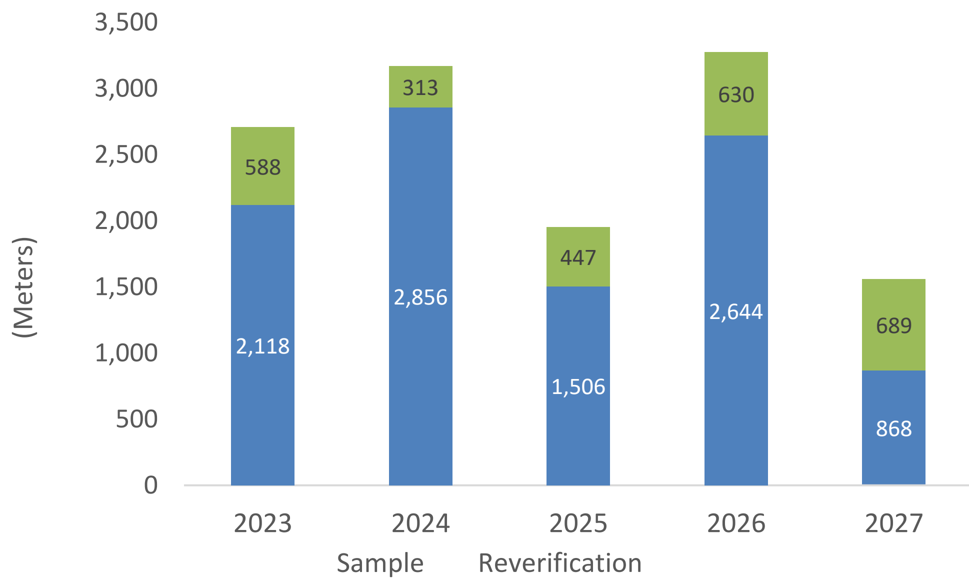


Figure 2: Sampling and Reverification Meter Inventory

In addition to the above, there is also the need to fund investments to address wholesale meter installations that no longer meet current standards, have reached end of service, or have an identified high degree of failure risk.

B. INVESTMENT DESCRIPTION

The Metering Sustainment program funds the following needs over the test period:

- Replacing failed AMI 1.0 meters (approximately 316,000 meters);
- Ensuring there are sufficient meters to address sampling and reverification regulatory requirements (approximately 12,700 meters);

- Upgrading non-standard meter installations to Hydro One Distribution's current wholesale and retail revenue meter standards as a result of acquisition due to a boundary change or the acquisition of an LDC;
- Upgrading WRMI to a retail revenue meter when customers choose to become a retail customer of Hydro One Distribution;
- Replacing WRMI Instrument Transformers with a high degree of failure risk (see DSP Section 3.2);
- Replacing aging and obsolete meter lab equipment to ensure compliance with Measurement Canada requirements to maintain accreditation as a licensed meter service provider for testing, verification and sampling of meters;
- Upgrading aging 600V self-contained meters with 120V transformer rated meters, since vendors are no longer supporting this form factor. Replacing these 600V meters with an inherently safer 120V unit increases employee and customer safety, and allows Hydro One Distribution to meet expired seal obligations.

C. OUTCOMES

Metering sustainment investments contribute to the following outcomes:

- Maintaining billing accuracy in accordance with the OEB's Distribution System Code by replacing failed meters in a timely manner and thus reducing estimated bills and bill corrections;
- Maintaining compliance with various requirements such as Measurement Canada's *Electricity Gas and Inspection Act* and regulations, and the IESO *Market Rules* to enable accurate and reliable billing;
- Ensuring a reliable source of billing settlement data that increases customer confidence and satisfaction that bills are accurate;
- Ensuring compliance with Measurement Canada requirements to maintain accreditation as a licensed meter service provider for testing, verification and sampling of meters.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Maintaining billing reliability and accuracy. • Reducing the duration of customer interruptions by maintaining an adequate inventory of components for timely replacement of failures. • Maintaining timely customer access to energy usage information.
Operational Effectiveness	• Reducing the need for manual meter reading. • Maintaining meter network reliability to ensure a reliable source of billing settlement data. • Maintaining operational efficiencies gained through AMI 1.0 (see DSP Section 3.3, Attachment 8).
Public Policy Responsiveness	• Compliance with OEB *Distribution System Code* (March, 2020) s. 5.1 and 7.11 requirements for metering services and billing accuracy. • Compliance with OEB *Standard Supply Service Code* (Oct. 2020) s.3.1 and 3.5 provisions for rates and consumer RPP pricing options. • Compliance with various provisions of the *Electricity and Gas Inspection Act*, R.C.S 1985, and related regulations with respect to Hydro One obligations for ensuring meter accuracy and ensuring meters are in good repair. • Compliance with various provisions of the *Weights and Measures Act*, R.S.C. 1985, and related regulations with respect to Hydro One obligations for ensuring meter accuracy and meter maintenance. • Compliance with IESO Market Rules for the Electricity Market (Feb. 2021), Chapter 6: Wholesale Metering.
Financial Performance	• Contributes to financial performance by ensuring energy consumption, and purchase of wholesale energy is measured accurately and in a timely manner.

D. EXPENDITURE PLAN

The costs for this program are projected based on these historic labour costs, material unit costs, and future anticipated needs.

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	65.1	58.3	42.9	26.8	13.5	206.6
Less Removals	2.5	2.7	2.8	4.7	4.5	17.1
Capital and Minor Fixed Assets	62.6	55.6	40.1	22.1	8.9	189.5
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	62.6	55.6	40.1	22.2	8.9	189.5

The factors influencing the cost of the investment include:

- The cost of material and term of procurement contracts;
- The volume and types of meters and network devices requiring replacement;
- The pacing of AMI 2.0 mass meter deployment; and
- The accessibility conditions of the area in which devices are being replaced. Accessing off road locations to replace network devices can be more costly due to the use of specialized equipment.

Controllable costs have been optimized through standardization of metering device purchasing specifications and issuance of vendor contract to secure unit pricing for procurement of materials.

E. ALTERNATIVES

This investment is non-discretionary. No alternatives were considered, since failure to perform the work to repair and/or replace the meters and associated network would not comply with regulatory requirements discussed in Section A.

F. EXECUTION RISK AND MITIGATION

No major risks are anticipated. Meter availability risk will be mitigated by optimizing inventory through an enhanced forecasting process (readjusting based on failures), and working closely with vendors.

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D-SR-01	DISTRIBUTION STATIONS DEMAND CAPITAL PROGRAM
Primary Trigger:	Asset Failure Risk
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness,

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	6.2	6.3	6.4	6.5	6.7	32.1

Summary:

This investment involves the replacement of failing and failed station components in order to maintain system reliability or restore power supply to customers. This investment also addresses environmental concerns such as the replacement of station service transformers with high polychlorinated biphenyls (PCB) content to meet Environment Canada regulations and the replacement of station transformers, which generate noise complaints from nearby customers. Finally, this investment addresses the need to replace overloaded equipment when identified to mitigate equipment failure and safety risk.

The primary trigger of the investment is asset failure risk: replacing station assets that have failed or are subject to imminent failure.

The investment is expected to sustain system reliability and operation by replacing failed station equipment in a timely manner, minimizing customer outage duration. This investment is also expected to mitigate failures by removing transformers from service that are at risk of imminent failure before failures occur, and by replacing equipment that is overloaded. The replacement of station equipment containing high PCB content will enable Environment Canada end-of-use deadlines to be met.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Asset failures or unplanned system deficiencies associated with various distribution station assets (transformers, reclosers, switches, insulators, station batteries and chargers, etc.) require immediate response by Hydro One personnel. If not rectified in a timely manner, such deficiencies and failures (including those caused or exacerbated by extreme weather) may result in significant service interruptions that require lengthy efforts to restore power, or present safety hazards to Hydro One employees or customers near the station or close to feeders protected by station equipment.

Service interruptions related to distribution stations can be addressed in some cases through switching and corrective repairs, while others must be addressed by replacement of failed station equipment through this investment program. From 2016 to 2018, there was an average of 19 unplanned equipment replacements per year under this investment related to Hydro One's distribution station equipment. From 2019 to 2020, this number of unplanned replacements rose to 28.

TRANSFORMERS

Hydro One monitors the condition of station transformers through routine inspections, annual oil sampling, and diagnostic testing, based on which a condition rating of "poor", "fair", or "good" is assigned. Hydro One manages its fleet of fair-condition transformers through corrective repairs and oil sampling. The fleet of poor-condition transformers is managed through a combination of corrective repairs, planned transformer replacements, and frequent oil sampling. Poor-condition transformers have the highest likelihood of failure. When it is discovered that failure of a poor-condition transformer is imminent, Hydro One will force the transformer out of service prior to the failure.

However, despite these efforts, transformer failures still occur and cannot be entirely eliminated. A large number of customers are impacted by station-related failures and when station transformers fail, service restoration requires a Mobile Unit Substation (MUS) as a temporary solution, which takes on average 6.6 hours (and in severe cases, up to 21 hours) to install before power is restored to customers. There are external factors that cause station transformers to fail such as lightning, system faults and animal contacts. As well, fair and poor-condition transformers, which have elevated dissolved gas analysis scores or moisture content in oil, are not immune to failure.

For example, the Hillsburgh DS T1 transformer suffered a failure in 2020 after a downstream feeder fault occurred due to a broken pole and two downed feeder conductors.

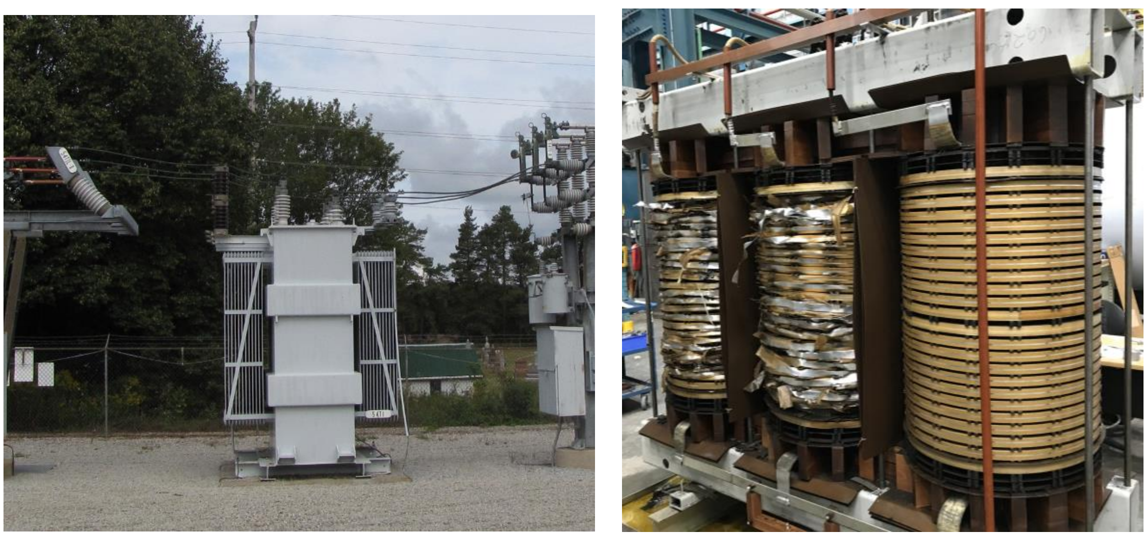

Figure 1: Failed Hillsburgh DS T1 Transformer & Windings (2020)

As another example, the Schreiber Winnipeg DS R1 regulator shown in Figure 2 suffered an internal fault. Prior to failure, the regulator was assessed as being in fair-condition due to elevated moisture content in the main tank. The regulator caught fire and the fire damaged the surrounding wooden structure, bus, insulators, and switches.

Figure 2: Failed Schreiber Winnipeg DS R1 Regulator (2020)

Hydro One categorizes distribution station transformer failures into the following two categories:

- *Class 1 failures* – Station transformer failures that resulted in customer interruptions. Customers are without power until a mobile unit substation (MUS) is installed to restore load. On average, these interruptions are 6.6 hours long. Historically, approximately 80% of Class 1 distribution station transformer failures have required replacement, while 20% were repairable.
- *Class 2 failures* – Station transformer failures avoided through oil sampling, which indicates that failure is imminent and triggers timely corrective or capital intervention. These failures do not result in a customer interruption. Upon observation of imminent failure, the relevant transformers are taken out of service and an MUS is installed at the station, where possible, to avoid customer interruption. Historically, approximately 40% of Class 2 transformer failures have required replacement, while 60% were repairable.

The number of transformer failures (Class 1) and the number of imminent failures avoided by removal of transformers from service (Class 2) are shown in Figure 3.

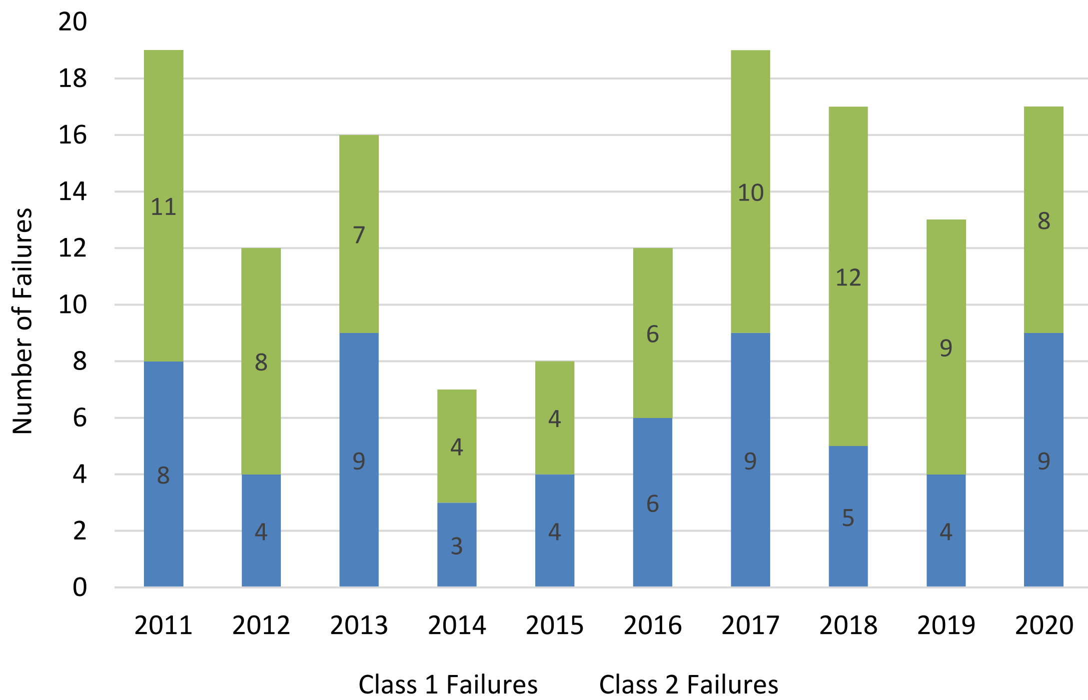

Figure 3: Failures of Station Transformers

For more information on station transformer performance, refer to DSP Section 3.2 (Distribution Asset Component Information) and Subsection 2.1.3 (Life Cycle Strategies).

44 KV & 27.6 KV MUS STRUCTURE REPLACEMENTS (ON DEMAND)

MUS Structures provide a connection point for MUS cables to be connected, and to allow the station power equipment to be by-passed during planned and unplanned station maintenance and capital work. When station transformers fail, an MUS must be connected to the MUS Structure at the station to bypass the failed transformer and restore power. If the MUS Structure is in poor condition when the transformer has failed, there is a need for the MUS Structure to be replaced before the MUS can be connected to restore load. MUS structures that are in poor-condition cannot safely be used to connect a MUS. Rotten poles and/or cross arms cannot bear the weight of MUS cables, posing a safety risk to Hydro One staff and any customers close to the station. Figure 4 is an example of a rotten MUS structure that broke and fell on a station transformer during a storm. Hydro One has a planned replacement program to address verified poor condition MUS structures over the JRAP period (see SR-03), whereas this Stations Demand program addresses the need to replace any poor condition MUS poles that may arise on a more urgent basis.

Figure 4: Broken MUS Pole at Bolton King DS

115 KV AND 230 KV MUS STRUCTURE INSTALLATIONS

Unplanned situations arise for which the station must be offloaded to an MUS for replacement of rotten/broken LV wooden structures, or to address power transformers with high PCB content (i.e., 50 ppm and above) in their bushings. Hydro One has 115 kV and 230 kV substations that were originally designed with single-phase power transformers and an on-site spare transformer for contingency, with no way to offload the transformer bank or the high-voltage (HV) or low-voltage (LV) bus without implementing a full station outage and interrupting customers. These stations require an unplanned installation of MUS connection facilities to enable the station to be offloaded. The unplanned replacement of station wooden structures and removal of high PCB content in transformers can take weeks to complete, and a sustained customer outage for that period of time would not be feasible.

OTHER FAILED STATION COMPONENTS

Hydro One inspects rural stations every six months and urban stations monthly. These regular inspections may identify damaged or failed distribution station assets that pose a safety hazard to customers or Hydro One employees and must therefore be promptly replaced. Broken insulators that support switches or buses are one such example. If they are not replaced, they can lead to equipment falling down. Failed station batteries or chargers that are used to operate breakers are another example. If these are not replaced, feeder breakers may not open when required to interrupt system faults, posing a public safety hazard.

ENVIRONMENTAL NEEDS

In addition to replacing damaged or failed distribution station assets, there is a need to address unplanned environmental concerns in stations. Hydro One must sample all oil-filled assets and remove PCB content at or above 50 ppm by 2025. When station service transformers and instrument transformers are sampled and found to have high PCB content, they must be replaced. These assets are most efficiently addressed through an unplanned capital program rather than a planned program, as it is difficult to predict the number of station transformers or instrument transformers that will be found to have PCB content at or above 50 ppm, and the quantities of such transformers are likely to be small.

Noise complaints from neighbouring customers relating to station transformers are another unplanned environmental concern that must be addressed. Transformers with noise levels that exceed the guidelines set out by the Ministry of the Environment, Conservation and Parks must either be replaced or have a noise barrier installed to reduce noise emission.

OVERLOADED EQUIPMENT

In rare circumstances, faster than anticipated load growth can lead to station transformers being loaded beyond their planned loading limits. Within the transformer, this can cause internal heating of paper insulation and windings, and lead to premature failure of the transformer.

As well, unforeseen system changes can lead to short circuit interrupting capabilities of station feeder reclosers being exceeded to a level that necessitates the need for unplanned replacement. Undersized reclosers may not be able to interrupt feeder fault currents.

Hydro One must replace such assets when they are identified in order to ensure the safety of employees and customers.

B. INVESTMENT DESCRIPTION

This investment addresses the following distribution station asset needs:

- Replacement of failing or failed equipment such as transformers, reclosers, switches, insulators, station batteries, and chargers in order to maintain distribution system reliability and operation.
- Replacement of assets that pose a safety risk to Hydro One employees or customers, such as transformers loaded beyond their planned loading limits, or reclosers with short circuit interruption ratings that have been exceeded.
- Unplanned installation of MUS connection facilities at 115 kV and 230 kV substations to enable stations to be offloaded to a MUS for replacement of rotten/broken LV wooden structures, or to address power transformers with high PCB content (i.e., 50 ppm and above). These stations were originally designed with single-phase power transformers and an on-site spare transformer for contingency, with no way to offload the transformers or HV or LV bus without implementing a full station outage and interrupting customers.

- Unplanned replacement of broken or unusable MUS poles at 44 kV and 27.6 kV substations required to enable demand capital work or demand corrective maintenance work.
- Replacement of high-PCB station service transformers and instrument transformers when they are identified.
- Replacement of transformers that generate noise complaints by neighbouring customers with noise levels that exceed the guidelines set out by the Ministry of the Environment, Conservation and Parks.

Demand station work such as the replacement of failed or failing equipment, equipment that poses safety risks, noise complaints and unplanned MUS facility installations are difficult to predict but must be addressed quickly, to mitigate customer interruptions, environmental and safety risks. Planned expenditures in this investment over the 2023 to 2027 planning period are forecasted based on the level of station demand capital work completed in recent years.

C. OUTCOMES

Customers will benefit from this investment through sustained reliability and system operation resulting from the replacement of failed station equipment in a timely manner, which will minimize customer outage duration. Customers will also benefit from the replacement of failing and overloaded station equipment before the failures occur, resulting in fewer customer interruptions and also mitigating safety risk to customers and Hydro One employees. Noisy transformers that generate customer complaints will also be replaced under this investment.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board’s (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Replacement of failed or high-risk equipment while minimizing customer interruption frequency and duration by installing/replacing MUS connection facilities and MUSs to offload stations during this work. Replacement of noisy transformers that generate customer complaints.
Operational Effectiveness	• Maintain distribution system reliability, operation and safety. Reduce safety risks associated with failed or overloaded equipment.
Public Policy Responsiveness	• Comply with the Distribution System Code Appendix C – Minimum Inspection Requirements, to ensure that appropriate follow up and corrective action is taken regarding problems identified during inspections.

D. EXPENDITURE PLAN

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	6.6	6.7	6.8	6.9	7.2	34.2
Less Removals	0.4	0.4	0.4	0.4	0.5	2.1
Capital and Minor Fixed Assets	6.2	6.3	6.4	6.5	6.7	32.1
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	6.2	6.3	6.4	6.5	6.7	32.1

The costs for this demand program are projected based on historical costs and future anticipated needs. The average investment cost for this program over the five-year period is in line with expenditures in more recent years. The factors affecting the costs in this investment are as follows:

- The scope of the replacement required to address the failure;
- The type and number of failed assets requiring replacement (i.e., transformers, switches, reclosers, poles, batteries, etc.);
- The type and number of station components requiring replacement on demand (i.e., station service transformers and instrument transformers with high PCB content, etc.);
- Number of stations requiring MUS connection facilities to be installed to support unplanned work; and
- The ratings of the equipment requiring replacement.

Controllable costs have been minimized through the standardization of station designs and equipment ratings, and the maintenance of a spare inventory for replacement of failed equipment to minimize outage time.

E. ALTERNATIVES

The replacement of failed or failing assets, assets that are overloaded, assets with high PCB content, and assets that generate customer noise complaints are all non-discretionary. Failure to respond to these failed or high-risk assets would violate the Distribution System Code, Ministry of the Environment Conservation and Parks regulations, and Environment Canada regulations. It would also result in unacceptable reliability and safety risks to customers. As a result, this alternative is rejected.

The only feasible alternative is to replace failed or failing assets, assets that are overloaded, station service or instrument transformers with high PCB content, and assets that generate customer noise complaints.

In order to replace these assets, the equipment must be offloaded. Alternatives 1A, 1B provide two alternatives to offload the equipment during the replacement of these assets.

ALTERNATIVE 1A: UTILIZE CUSTOMER OUTAGES DURING REPLACEMENT OF FAILED/HIGH-RISK EQUIPMENT

This alternative would utilize forced outages during the replacement of this equipment when MUS facilities are not available or cannot be used due to their condition. Under this alternative, customers could be out of power for weeks while equipment is being replaced which is not viable. As a result, this alternative is rejected.

ALTERNATIVE 1B: USE MUS CONNECTION FACILITIES DURING REPLACEMENT OF FAILED/HIGH-RISK EQUIPMENT (RECOMMENDED)

Under this alternative, when MUS facilities are not available or cannot be used due to their condition, they will be installed or replaced, respectively, as a demand capital investment.

This would allow Hydro One MUSs to be used to offload the station assets during the replacement of the failed or high-risk equipment, thereby avoiding prolonged customer outages or costly OM&A expenditures for generator rentals. Hydro One can replace 44 kV and 27.6 kV MUS poles in an emergency situation much faster than the time required to obtain generators, which means that customers will be interrupted for a shorter period of time. This alternative would also improve reliability at the station because it would enable MUSs to be connected in a timely manner in the event of any future asset failures. For these reasons, this alternative is recommended.

F. EXECUTION RISK AND MITIGATION

The work in this investment is unplanned in nature. The primary risk for executing this unplanned work is the availability of the MUSs. This risk is mitigated by ensuring that there is always at least one MUS available for emergent work in each voltage/capacity category and by having a process to enable reprioritization of MUSs to support the immediate and emergent work as required.

The secondary risk for executing the work under this investment is the availability of spare power equipment to replace equipment that has failed. The lead time to acquire replacement equipment can delay project work. This risk is mitigated by maintaining a spares inventory and regularly monitoring spare inventory levels.

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D-SR-02	MOBILE UNIT SUBSTATION PROGRAM
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	3.5	4.2	2.9	3.3	4.6	18.5

Summary:

This investment involves the replacement of Mobile Unit Substations (MUS) and Mobile Unit Substation transformers that are in poor condition. The prolonged use of these assets increases the reliability and safety risk to Hydro One employees and the general public. This investment also involves the expansion of the MUS fleet to provide a sufficient number of MUS for station transformer failure response, and to support all planned and unplanned station maintenance and capital work.

The primary trigger of the investment is the failure risk associated with MUS transformers and MUS trailers in poor condition.

The investment is expected to maintain the condition of the MUS fleet to mitigate risks to Hydro One staff and the general public. This investment is also expected to enable distribution stations to be offloaded to an MUS when required to execute work programs without unacceptable outage impacts to customers.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One owns, maintains and operates a fleet of 35 mobile unit substations (MUS) to support the majority of distribution stations that have very limited capability to transfer load within the station or to other stations. MUSs have similar components to a distribution station such as a stepdown transformer, reclosers, fuses and switches, however these components are mounted on a trailer. These MUS perform an integral role in the operation of Hydro One's distribution system and are utilized for the following purposes:

- For emergency power restoration in the event of a transformer or other distribution station component failure; and
- To offload distribution stations during maintenance and capital activities.

MUS enable the following work programs by providing a means of offloading station equipment during maintenance or replacement without interrupting customers:

- *Distribution stations demand capital program* work as outlined in ISD D-SR-01,
- *Distribution station refurbishment* program work as outlined in ISD D-SR-04,
- *System upgrades driven by load growth* as outlined in ISD D-SS-01 and
- *Distribution stations sustaining OM&A* program work including planned preventive maintenance, demand and planned corrective maintenance work as outlined in *Distribution Sustainment OM&A* exhibit E-03-02.

Hydro One maintains its MUS assets to ensure that an adequate, safe and reliable fleet is available to satisfy the requirements noted above. Without a sufficient number of available, well-maintained MUSs, Hydro One would not be able to supply customers during planned station maintenance and capital work which is usually performed without interruptions to customers. Also, without a sufficient number of available MUSs to support reactive stations work, outage durations could be extended by several days when equipment failure occurs.

The MUS fleet must adhere to the requirements of the *Highway Traffic Act*. Under the *Highway Traffic Act*, each MUS must receive an annual vehicle safety and structural inspection from an approved facility to certify that they meet minimum safety requirements. If an MUS does not pass the annual inspection, it cannot be transported as it poses a safety risk to Hydro One employees and the public. As a result, it is imperative that poor-condition MUS trailers are addressed to ensure usability. As documented in DSP Section 3.2, nine MUS trailers are in poor condition. The condition profile of the MUS trailers is shown in Figure 1 below.

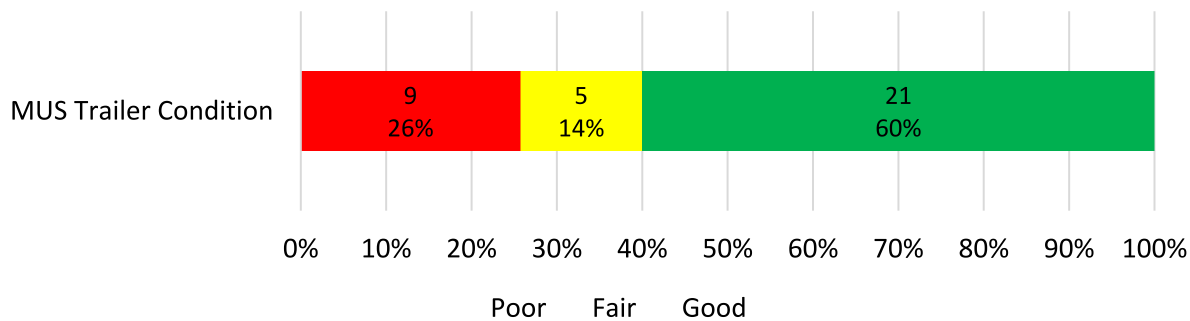

Figure 1: MUS Trailer Condition

Factors which contribute to the poor condition of MUS trailers include rust, worn suspension or landing gear, failing brakes or electrical systems. The prolonged use of a poor-condition MUS could increase the safety risk to Hydro One employees and the general public.

MUS 30 is an example of one such MUS that is in need of replacement due to the condition of the trailer and the transformer. Figure 2 below provides pictures of the MUS 30 trailer, cable reel and landing gear with major rust. The transformer for MUS 30 is also in poor condition based on oil sample results.

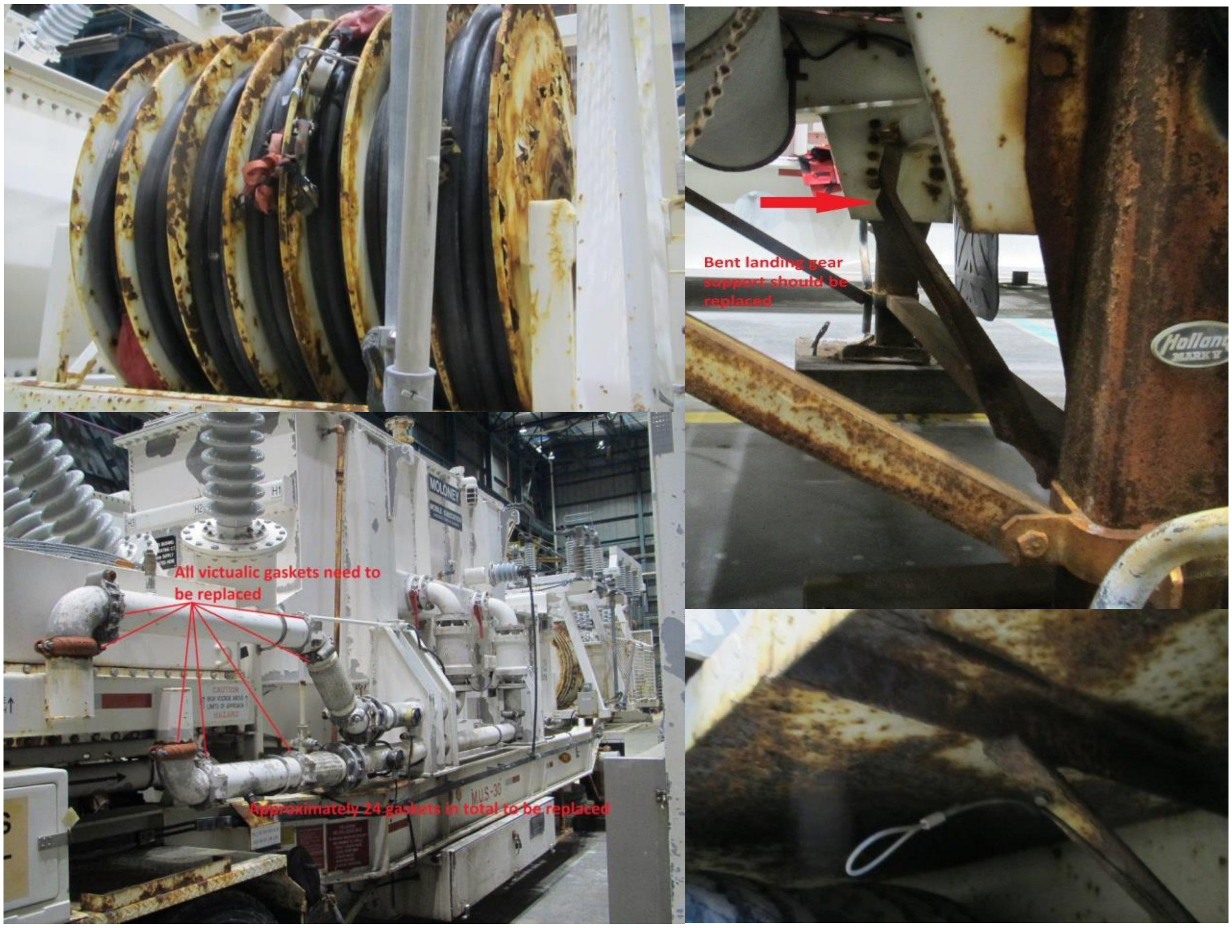

Figure 2: MUS 30 Trailer in Poor Condition

Fourteen MUS transformers are in poor condition based on annual oil sampling, testing and inspection to monitor their condition. The condition profile of the MUS transformers is shown in Figure 3 below.

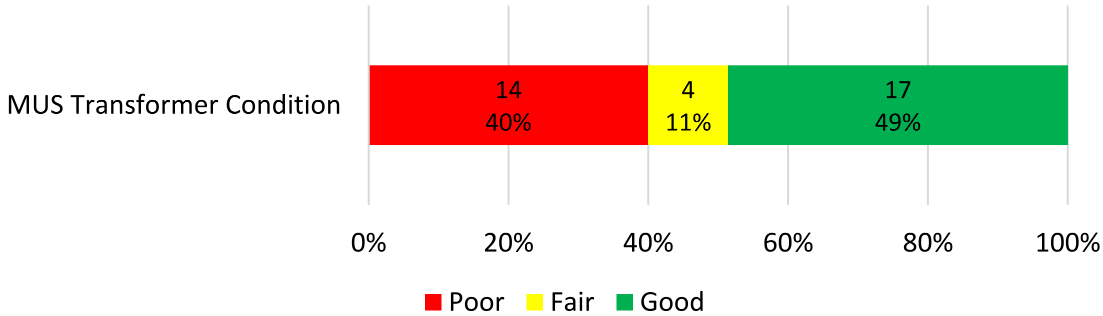

Figure 3: MUS Transformer Condition

In 2014, the MUS 35 transformer suffered a failure. The MUS 26 transformer also suffered a failure in 2018. Figure 4 below depicts the failed MUS 26 transformer. Both MUS transformers were in poor condition prior to failure and the planned replacement of other poor condition MUS transformers is required to prevent similar failures.

Figure 4: MUS 26 Transformer Failure

Hydro One must maintain a variety of different types of MUSs, since the MUS transformer must align with the voltage and capacity of the station equipment it replaces during an outage. In recent years, planned station work at 44 kV stations with transformers equipped with under-load tap-changers (to automatically control voltage) was deferred due to MUS unavailability in this category. MUSs which were scheduled for planned station work had to be redeployed to support reactive work following equipment failure, or had to be made available on emergency standby to support any additional failures. In 2018, Hydro One had 10 MUSs in this category, and this was increased to 12 MUSs in 2019. Hydro One now has 14 MUSs in this category. Over this historic period, approximately 15 MUSs in this category would have allowed all planned and reactive work to be completed, while providing MUSs to be available on standby to support any subsequent failures. To ensure there is an adequate number of MUSs to accomplish all planned and unplanned station work and provide emergency failure response when required, the 44 kV MUS fleet must be expanded by one unit.

B. INVESTMENT DESCRIPTION

Over the 2023-2027 period, Hydro One plans to replace MUSs that are in poor condition and MUS transformers that are in poor condition. Hydro One also plans to purchase one additional MUS in this period, as required to support the distribution system and proposed work programs.

MUSs that have been identified for replacement have MUS trailers and transformers in poor condition, and are prioritized based on their level of risk. In cases where the MUS trailer is in good condition but the transformers are in poor condition, only the MUS transformer will be replaced.

As outlined in DSP Section 3.2, fourteen of the MUS transformer condition assessments fall into the poor condition category, while nine of the MUS trailers are in poor condition. Also some of the MUS transformers have limited capacity or lack voltage regulation capability, which limits the utilization of the MUS. The expenditures planned for 2023-2027 are intended to maintain the historic station transformer failure response restoration time, and have sufficient MUSs to allow for the completion of planned and unplanned capital and maintenance work.

Based on these assessments, two MUSs are planned for replacement, six MUSs have been identified to have transformer replacements and one new MUS will be procured to expand the fleet over the five year period as outlined in the table below.

Table 1 - In-Service Forecasts for MUS Program Work

Program Categories	2023	2024	2025	2026	2027
MUS Replacements	1	-	-	-	1
MUS Transformer Replacements	-	1	2	2	1
MUS Fleet Expansion	-	1	-	-	-
Total	1	2	2	2	2

The MUS and MUS transformers will be replaced with units that have higher MVA capacity in line with current standards and will include voltage regulation to support a higher number of stations.

C. OUTCOMES

The mobile unit substation program will result in:

- Maintaining a reliable MUS fleet to respond to station failures with emergency power restoration and maintain the historic station transformer failure response restoration time.
- Enabling distribution stations to be offloaded to an MUS to execute the proposed capital and OM&A work programs without unacceptable outage impacts to customers; and
- Maintaining the condition of the MUS fleet to mitigate risks to Hydro One staff and the general public.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF).

Table 2 - Outcome Summary

Customer Focus	• Reduce customer interruption time by ensuring an adequate level of MUSs to provide emergency power restoration to failure events.
Operational Effectiveness	• Maintain the reliability of the distribution system by sustaining an adequate level of MUSs to carry the distribution station load while performing capital and maintenance work to mitigate power disruption to customers. • Utilization of MUS's provides a cost effective alternative to constructing redundant transformation at distribution stations across the province.
Public Policy Responsiveness	• Comply with Ministry of Transportation licensing requirements by ensuring the units are roadworthy and electrically functional.

D. EXPENDITURE PLAN

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	3.5	4.2	2.9	3.3	4.6	18.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**3.5**	**4.2**	**2.9**	**3.3**	**4.6**	**18.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.5**	**4.2**	**2.9**	**3.3**	**4.6**	**18.5**

The factors influencing the cost of the investment include:

- The number of MUSs that are being purchased each year as well as their ratings (e.g. 115 kV vs. 44 kV high-side voltage).
- The number of MUS transformers that are being replaced each year.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: REACTIVE REPLACEMENT

Under a reactive replacement approach, Hydro One would wait for MUS transformer and trailer components to fail, and replace the failed MUS transformers and trailer components on a reactive basis. Hydro One rejected this alternative for several reasons. When MUS components fail, the MUSs are unavailable until the failed components are replaced. The lack of availability of an appropriate level of MUS fleet would have a negative impact on emergency power restoration and system reliability. Since the lead time to replace a failed major MUS component such as the transformer or trailer is 1.5 to 2 years, the potential impact on system performance and customer reliability resulting from a reactive replacement strategy could be significant. Such an approach would limit the capability of the MUS fleet to support emergency power restoration and/or capital and maintenance activities and is rejected as a result.

ALTERNATIVE 2: RENEWAL OF THE MUS FLEET

Under a renewal-only approach, Hydro One would replace MUSs with new complete units when both MUS transformers and trailers are in poor condition. This approach would also entail replacing MUS transformers that are in poor condition which reside on trailers that are in good condition. The company would replace two MUSs that are at end-of-life and replace an additional six MUS transformers that are in poor condition.

This approach would address the condition of the existing fleet by replacing eight out of fourteen poor condition MUS transformers and two out of nine poor condition MUS trailers.

However, this alternative would not address the shortfall in the MUS fleet. Hydro One rejected this alternative since the existing MUS fleet level is insufficient to address demands of the proposed work program and emergency power restoration.

ALTERNATIVE 3: RENEWAL AND EXPANSION OF THE MUS FLEET (RECOMMENDED)

Under the recommended approach, Hydro One would replace MUSs with new complete units when both MUS transformers and trailers are in poor condition, replace MUS transformers that are in poor condition which reside on trailers that are in good condition. This would include the replacement of two MUSs that are in poor condition and replacing an additional six MUS transformers that are in poor condition. Hydro One would also expand the MUS fleet to address the shortfall to meet the demands of the proposed capital and OM&A work programs and emergency power restoration needs.

Like Alternative 2, this approach will addresses the condition of the existing fleet by replacing eight out of fourteen poor condition MUS transformers and two out of nine poor condition MUS trailers. The MUS fleet will be expanded by one unit in 2024 to address immediate work program needs, and progress payments will be made towards one additional unit in 2027 for delivery in 2028 to support the condition of the MUS population in the future.

F. EXECUTION RISK AND MITIGATION

The risks to completion of this investment as planned are the time required to execute MUS and MUS transformer procurement processes, and the availability of vendors to manufacture and deliver these units to Hydro One. Depending on when in the year the manufacturer receives the request for procurement, they may be fully booked and not able to immediately accommodate the request. These risks are mitigated by early evaluation of vendors, and by providing MUS and MUS transformer procurement forecasts to vendors in advance to ensure that they will be able to accommodate the requests and issuance of the purchase orders in a timely matter.

D-SR-03	DISTRIBUTION STATION PLANNED COMPONENT REPLACEMENT PROGRAM
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	4.6	3.3	1.1	1.2	1.2	11.4

Summary:

This investment funds the replacement of MUS Structures that are in poor condition because they cannot be utilized for MUS installations at substations. This investment will allow MUSs to be installed at stations to enable planned maintenance and capital work, and mitigate the risk of lengthy equipment outages, allowing for timely connection of MUSs upon equipment failure

This investment also funds the replacement of Cooper Type L oil hydraulic reclosers with vacuum interrupter hydraulic controlled reclosers when they are in poor condition, or when the manufacturer recommended operation limit has been exceeded. Vacuum interrupter reclosers have a lower lifecycle cost in comparison to maintaining Cooper Type L reclosers. This investment will mitigate the risk of safety concerns resulting from reclosers failing to operate, maintain system reliability by ensuring that reclosers are able to clear system faults, and reduce the lifecycle cost for hydraulic reclosers.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Over the 2023-2027 period, the Distribution Station Planned Component Replacement Program addresses the need to replace two categories of distribution stations equipment:

i. Poor condition mobile unit substation connection structures (MUS Structures) and
ii. Cooper Type "L" oil interrupter hydraulic controlled reclosers that are in poor condition or have exceeded the manufacturer recommended operation limit.

When these assets deteriorate, they pose reliability and safety risks to Hydro One staff and customers, and should be replaced under a planned investment. This section summarizes the need for planned investments to address these deteriorated assets.

MUS STRUCTURES

As described in ISD D-SR-02, mobile unit substations (MUS) are essentially "substations on wheels" that can be transported to distribution stations to restore power in the event of a transformer or other distribution station component failure, and to offload distribution stations during maintenance and capital activities.

MUS Structures provide a connection point for MUS cables to be connected and allow the station power equipment to be by-passed during planned and unplanned station maintenance and capital work. Hydro One has MUS Structures which are deteriorated and must be replaced. As identified in DSP Section 3.2, 67 MUS Structures are currently in poor condition and 207 are in fair condition. The condition profile of MUS Structures is shown in Figure 1 below:

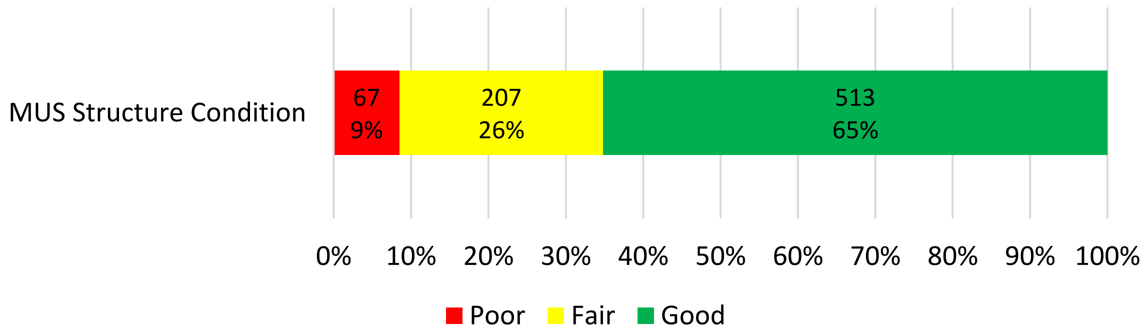

Figure 1: MUS Structure Condition (as of Dec. 31, 2020)

The health of MUS Structures are identified through routine station inspections whereby the condition of the structure, cross arms, footings, insulators and grounding are evaluated. Poor condition MUS Structures cannot be utilized for MUS installations at substations until they are replaced.

MUS Structures have wooden poles and cross arms which must be strong enough to bear the weight and tension of MUS feeder cables or conductors. As MUS Structures age, the wooden components including poles and cross arms will rot and can become hollow on the inside. When this occurs the integrity of the MUS Structure is reduced and it is no longer strong enough to support MUS cables. Figure 2 below is an example of a MUS Structure which has rotten wooden poles and cross arms. The top cross arm has a large hole, and the left pole is split down the middle.

Figure 2: MUS Structure With Rotted Poles & Cross-Arms

Wooden MUS Structures can also be subjected to damage from a variety of factors, including insects and animals. Figure 3 shows a hollow stub from a MUS Structure which was replaced. The stub has a hole on the right side and is hollow and the structure this stub belonged to would not be safe to use.

Figure 3: Stub From A Hollow MUS Structure That Was Replaced

Some MUS Structures start to lean overtime and also cannot be utilized for MUS installations. Figure 4 below is a picture of a MUS Structure that is planned for replacement in 2021.

Figure 4: Leaning MUS Structure

Rotten, hollow or leaning MUS Structures cannot safely hold the weight of MUS cables and are not safe to be utilized for MUS installations. MUS cables installed at poor-condition MUS Structures pose potential safety risks. If MUS cables were connected to poor-condition MUS Structures, the cables, cross arms or poles may be at risk of falling on or near Hydro One staff also presenting an electrical hazard.

There is also a reliability impact associated with poor condition MUS Structures. MUS Structures in poor condition cannot be utilized for MUS connections when an MUS must be installed to enable planned or unplanned station maintenance or capital work. Accordingly, if poor MUS Structures are not replaced, planned maintenance and capital activities to address reliability cannot proceed.

Also, MUSs cannot be connected to MUS Structures that are in poor condition to restore customer load when station components (such as transformers) fail. In these emergent situations, the poor condition MUS Structure must be removed and replaced with a new MUS Structure prior to the installation of an MUS to restore load to customers. In severe cases this can add 10 or more hours to equipment restoration times and result in prolonged outages for customers.

OIL INTERRUPTER HYDRAULIC CONTROLLED RECLOSERS

Station reclosers are required to remove assets from service under fault conditions. Reclosers rapidly open and reclose in attempt to clear system faults, restoring service to customers. When system faults occur on the feeders downstream, it is important that reclosers operate at the right time and speeds to clear system faults maintaining reliability, or to lock out when required for public safety. In distribution stations, 1217 feeders are equipped with oil interrupter hydraulic controlled reclosers. Of these, 895 or approximately 74% are Cooper Type L reclosers.

The condition of reclosers is primarily driven by the condition of the recloser contacts which enable arc extinction. Contact wear is driven by the number of operations as well as the interrupter type. Manufacturers for hydraulic recloser recommend maintenance based on the number of counter operations they undergo. Open and reclose operations wear out contacts. Defects such as hot spots identified through thermographic inspections, damaged bushings, damaged connectors, rusted tanks or oil leaks identified through visual inspections also impact recloser condition. Worn contacts and defects observed through thermographic inspections and visual inspections can all lead to recloser failure if not addressed.

When Cooper Type L reclosers have reached the manufacturer recommended operation limit prior to maintenance, Hydro One replaces these oil hydraulic reclosers with vacuum hydraulic reclosers instead of maintaining them. The maintenance of oil hydraulic reclosers involves removal of the recloser, replacement of oil, contacts and other worn components, test operation and reinstallation of the recloser. The lifecycle cost of replacing Type L reclosers with new vacuum hydraulic reclosers is lower in comparison to the lifecycle cost of maintaining Type L reclosers when manufacturer recommended operation limits are reached.

Figure 5: Poor Condition Cooper Type L Oil Hydraulic Reclosers

OTHER STATION COMPONENTS

In addition to MUS Structures and oil hydraulic reclosers, distribution stations include many other components, including transformers, station service transformers, switches, station structures, grounding systems, bus, insulators, batteries, chargers, fences and gates. The planned renewal of this equipment is typically executed under Distribution Station Refurbishment investments as outlined in ISD D-SR-04. When these components fail, they are typically replaced under the Distribution Station Demand Capital Program as outlined in ISD D-SR-01.

B. INVESTMENT DESCRIPTION

Over the 2023-2027 period, Hydro One plans to replace 75 poor condition MUS Structures, and Type L oil hydraulic station reclosers for 401 feeders. Table 1 below summarizes the MUS

Structure replacement and Type L recloser replacements over the 2023 to 2027 planning period. The replacement of Type L reclosers is planned for completion by 2024 in order to address these reclosers as they reach the manufacturer recommended operation limit.

Table 1 - Number of Planned Component Replacements

Component	2023	2024	2025	2026	2027
MUS Structures	15	15	15	15	15
Hydraulic Reclosers (Feeders)	247	154	-	-	-
Total Component Replacements	**262**	**169**	**15**	**15**	**15**

Deteriorated MUS Structures and oil interrupter hydraulic controlled reclosers are prioritized for replacement based on inspection results. Station visual inspections are performed at least twice per year at which time MUS Structures and hydraulic recloser condition is assessed. Oil hydraulic recloser counter operations are also recorded and monitored at that time.

MUS STRUCTURE REPLACEMENTS

MUS Structures identified in poor condition require replacement to maintain the reliability of the system. 67 MUS Structures have been evaluated to be in poor condition and 207 MUS Structures evaluated as in fair condition. Over the 2023 – 2027 planning period, 75 MUS Structures are planned for replacement. By 2027, it is expected that the condition of 70 – 80 MUS Structures will move from the fair condition category into the poor category. The pacing of 15 MUS Structures per year is expected to maintain the current condition profile of MUS Structures.

MUS Structures in poor condition must be addressed before a MUS can be installed at the station. MUS Structure replacement projects can include replacement of ingress poles outside the station, installation of additional poles and in-line switches inside the station fence, and other potential modifications to provide enough space for a MUS and MUS Structure to be located inside.

OIL INTERRUPTER HYDRAULIC CONTROLLED RECLOSER REPLACEMENTS

In distribution stations, 1217 feeders are equipped with oil interrupter hydraulic controlled reclosers. Of these, 895 or approximately 74% are Cooper Type L. Hydro One plans to replace all Cooper Type L oil hydraulic reclosers with vacuum interrupter hydraulic controlled reclosers when they are in poor condition, or when the manufacturer recommended operation limit has been exceeded. The lifecycle cost of replacing Type L reclosers with new vacuum hydraulic reclosers is lower in comparison to the lifecycle cost of continuing to maintain Type L reclosers.

Hydro One began the replacement of Cooper Type L oil hydraulic reclosers with vacuum hydraulic reclosers in 2019 and these replacements continued in 2020. Of the remaining 895 station feeders with Cooper Type L reclosers, 494 feeders will be upgraded to vacuum hydraulic reclosers over 2021 and 2022. These reclosers are replaced live, and equipment outages are not required for their replacement. As shown in Table 1, reclosers for 247 feeders are planned for replacement in 2023, and reclosers for the remaining 154 feeders are planned for replacement in 2024. With the proposed plan, Cooper Type L reclosers are expected to be phased-out and replaced with vacuum hydraulic reclosers by 2024. This pacing is based on Hydro One's estimation that manufacturer recommended operation limits for all Type L reclosers would be exceeded by 2024.

C. OUTCOMES

The planned replacement of MUS Structures will result in:

- Allowing MUSs to be installed at stations to enable planned maintenance and capital work.
- Mitigating the risk of lengthy equipment outages by replacing poor condition MUS Structures, allowing for timely connection of MUSs upon equipment failure. This can reduce outages related to equipment failure by more than 10 hours.

The replacement of Cooper Type L oil hydraulic reclosers with new vacuum hydraulic reclosers will result in:

- Reduced lifecycle costs for station hydraulic reclosers, as new vacuum hydraulic reclosers have a lower lifecycle cost.
- Mitigating the risk of safety concerns resulting from reclosers failing to operate. Reclosers must be able to clear faults on downstream feeders.
- Maintaining system reliability by ensuring that reclosers are able to clear system faults and rapidly restore power to customers.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF).

Table 2 - Outcome Summary

Customer Focus	• Reduce customer interruption time by replacing poor condition MUS Structures to enable timely MUS connection following station equipment failure.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by replacing poor condition reclosers to mitigate recloser failure incidents.
Public Policy Responsiveness	• Comply with the Distribution System Code Appendix C – "Minimum Inspection Requirements" to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	• Replacement of oil hydraulic reclosers with new vacuum hydraulic reclosers which have a lower lifecycle cost.

D. EXPENDITURE PLAN

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 -Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	4.9	3.6	1.2	1.3	1.3	12.3
Less Removals	0.3	0.3	0.1	0.1	0.1	0.9
Capital and Minor Fixed Assets	**4.6**	**3.3**	**1.1**	**1.2**	**1.2**	**11.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**4.6**	**3.3**	**1.1**	**1.2**	**1.2**	**11.4**

The main factor influencing the cost of the investment include the extent of the requirements at each station to replace MUS Structures, which can vary depending on the station design. MUS Structure replacement projects can include replacement of ingress poles outside the station, installation of additional poles and in-line switches inside the station fence, and other potential modifications to provide enough space for a MUS and MUS Structure to be located inside.

The higher costs in years 2023 and 2024 are due to the planned recloser upgrades being performed in those years. The replacement of Cooper Type L oil hydraulic reclosers with vacuum hydraulic reclosers began in 2019 and with the proposed funding, are expected to be completed by 2024.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: REACTIVE REPLACEMENT OF MUS STRUCTURES & OIL HYDRAULIC RECLOSERS

Under the reactive replacement approach, Hydro One would not replace MUS Structures that are in poor condition and would not upgrade oil hydraulic reclosers to vacuum hydraulic reclosers.

If poor condition MUS Structures are not replaced on a planned basis, then MUSs will not be able to be installed to restore load when station components fail. The MUS Structure would need to be replaced on a reactive basis following the station component failure. This can add 10 or more hours to equipment restoration times and customers will experience prolonged outages. Also, stations will not be able to receive planned maintenance or capital upgrades if the MUS Structures are not usable. Lack of maintenance and capital investment at poor condition stations increases the reliability risk.

If oil hydraulic reclosers are not upgraded to vacuum hydraulic reclosers, then they must undergo maintenance, whereas they could have been replaced with more reliable newer vacuum technology reclosers, which also require four times less maintenance work. The lifecycle cost of maintaining a feeder with Type L reclosers is much higher in comparison to the lifecycle cost of replacing with new vacuum hydraulic reclosers.

This alternative is rejected for MUS Structures and oil interrupter hydraulic controlled reclosers for the reasons described above.

ALTERNATIVE 2: PLANNED REPLACEMENT OF MUS STRUCTURES & OIL HYDRAULIC RECLOSERS (RECOMMENDED):

Under the recommended alternative, MUS Structures identified as in poor condition will be replaced on a planned basis and oil interrupter hydraulic controlled reclosers that are in poor condition or have had counter operations that exceeded manufacturer recommended levels, will be replaced with vacuum interrupter hydraulic controlled reclosers. This alternative is recommended for the following reasons:

The planned replacement of poor condition MUS Structures allows equipment outages to be kept to a minimum, saving up to 10 hours of customer interruption time. These replacements of poor condition MUS Structures enables MUSs to be installed to provide for substation maintenance and planned capital work.

The upgrade of oil interrupter hydraulic controlled reclosers to new vacuum interrupter hydraulic controlled reclosers is a cost effective strategy for which vacuum hydraulic reclosers offer a much lower lifecycle cost, and the maintenance requirement of vacuum reclosers is less than oil reclosers by a factor of four.

This alternative maintains the safe and reliable operation of distribution stations.

F. EXECUTION RISK AND MITIGATION

The main risk that can impact the completion of this investment is outage availability. This risk is mitigated through up front planning, scheduling, and outage coordination across lines of business and stakeholders. In the event a necessary outage cannot be obtained, other poor condition MUS Structure replacements can be advanced to ensure that overall work execution plan is not impacted.

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D-SR-04	DISTRIBUTION STATION REFURBISHMENT
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	44.8	41.5	28.5	32.3	32.1	179.1

Summary:

This investment involves the planned replacement of station transformers that have been assessed to be in poor condition. The primary trigger of the investment is the condition of the station transformer. The investment will also address other end of life components within the station where appropriate in a bundled fashion. By proactively addressing poor condition transformers and equipment, this investment is expected to mitigate failures to maintain reliability of the distribution system.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One owns, maintains, and operates 992 distribution and regulating stations in Ontario. Of those, 919 are distributing stations which serves an average of 1,500 customers. The vast majority of these stations are a single transformer design with limited ability to transfer load to an alternative supply during a contingency situation. Assets in a distribution and regulating station include the transformer, reclosers and breakers, switches and fuses, station structure, mobile unit substation (MUS) structure, fence, station grounding system, station service transformer, insulators, bus work, protection relays and IEDs. As discussed in DSP Section 3.2, significant quantities of Hydro One's distribution station assets are in poor condition and will continue to deteriorate, leading to an increased likelihood of failures and associated increase in reliability and safety risk.

Hydro One has 1,197 distribution transformers. Transformer condition is assessed through oil sampling, thermography (infrared heat detection), and visual inspections. Many factors lead to the degradation of a transformer's internal components over time including transformer loading, switching, lightning surges, faults, moisture contamination, and paper insulation degradation. This deterioration and the resulting asset condition is one of the leading predictive indicators of transformer failure.

As shown in Figure 1 below, approximately 20% of the overall transformer population is categorized as being in poor condition. These transformers are subject to an elevated risk of failure and are considered for replacement or corrective repair to address deficiencies before failures occur and impact service to distribution customers.

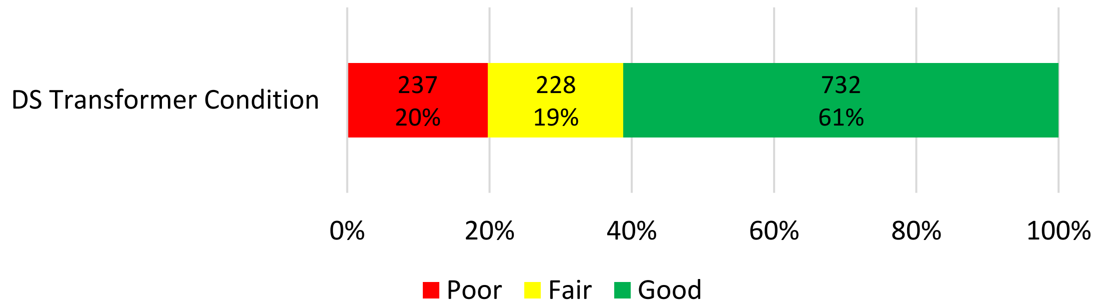

Figure 1: DS Transformer Condition

Station transformers are the most important asset component at a station. Poor-condition transformers need to be proactively addressed in a timely manner in order to limit the number of unplanned transformer failures. There are two categories of transformer failures – failures that result in unplanned customer interruptions (referred to as "Class 1" failures) and imminent failures identified through testing and avoided by removing a transformer from service (referred to as "Class 2" failures). Without an adequate station refurbishment plan over the long term, there would be an expected increase in the number of Class 1 and 2 failures. Class 1 failures result in unanticipated and potentially long duration outages for customers. Even though a Class 2 failure does not result in actual customer interruptions, a higher incidence would place pressure on Hydro One's distribution station demand capital program (D-SR-01) as well as the company's limited fleet of MUSs that need to be deployed to minimize customer outages resulting from such failures. Figure 2 shows the number of Class 1 & Class 2 failures experienced over 2011-2020.

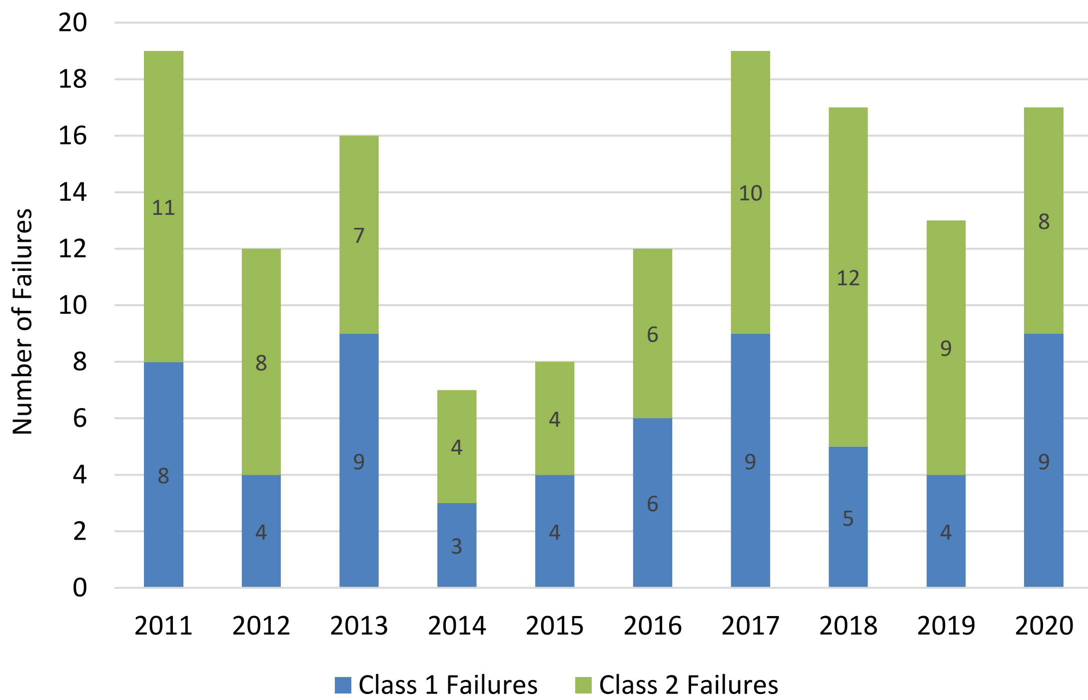

Figure 2: Class 1 and Class 2 Transformer Failures (2011-2020)

This investment involves the planned replacement of station transformers that have been assessed to be in poor condition. If there are other station assets that are in poor condition and in need of replacement, they are also bundled with the transformer replacement. Assets that are in good or fair condition are not replaced. Equipment identified as obsolete is decommissioned (where no longer needed) or replaced with standard equipment along with the transformer replacement during refurbishment. Additionally, various station design elements will be taken into consideration such as higher capacity transformer units, additional station feeder positions and installing electronic reclosers to meet known future capacity requirements and installation of MUS structures to enable temporary bypass supply during station outages or a combination of these factors. Other factors considered include the potential need for soil remediation or mitigation of environmental risks.

In the event of a transformer failure at the distribution station, all customers supplied by that distribution station would experience an interruption of service until power is restored through the repair/replacement of the failed equipment or the connection of an MUS. These power restoration efforts can take up to 21 hours depending on the severity of the failure, the location of the station, and the infrastructure available to accommodate an MUS. If an adequate planned refurbishment is not undertaken, more failures would mean less availability of MUS, and if an MUS is not available then customers can experience significantly longer outages. Over the last five years, there has been a combined average of 15.6 Class 1 and Class 2 transformer failures per year. It takes an average of 6.6 hours for an MUS to be installed to resume service for customers following Class 1 failures.

B. INVESTMENT DESCRIPTION

This investment involves the refurbishment of distribution and regulating stations to address station transformers and equipment identified as being in poor condition and posing a reliability and/or safety risk. The proposed plan is to refurbish 92 stations, with an average of 18 distribution and regulating stations per year over the five-year planning period, as shown in Appendix A. These station refurbishments – together with other investments addressing poor condition transformers and corrective maintenance – are expected to maintain the current proportion of poor condition transformers at approximately 20%. Through these investments, Hydro One aims to maintain the current level of station reliability through a pacing level that is supported by customers as identified through customer engagement. This translates to 118 poor condition transformers over the 5 year period. There are 106 poor condition transformers that will be addressed under this investment while another 12 will be addressed under D-SR-11.

When a station transformer is in need of replacement, the overall station design and system needs are evaluated to determine the most cost-effective course of action. This includes an assessment of whether a pad-mounted distribution station (PDS) is a suitable solution. A PDS may be a low- cost option when compared to traditional refurbishments, due to the reduced cost of the power transformer, simplistic high/low voltage bus work, lack of station structure/fencing, and reduced engineering requirements. In order for a PDS to be a feasible alternative to a traditional refurbishment, specific criteria must be met. Examples of this criteria include limited existing (and forecast) loading due to PDS capacity limitations and adequate voltage support as the PDS design does not include the possibility of an Under Load Tap Changer (ULTC).

C. OUTCOMES

The station refurbishment program will result in the following outcomes:

- Maintain safe and reliable distribution system operation by addressing poor condition station transformers (bundled with other poor condition components where appropriate) through refurbishments.
- Where appropriate, provide sufficient capacity to meet customer loading requirements for the foreseeable future.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Avoid customer interruptions by proactively addressing poor condition station transformers and equipment prior to failure.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution station by addressing poor condition station equipment in an integrated and cost-effective manner.
Financial Performance	• Realize cost savings by deploying cost-effective Padmount Distribution Stations where feasible. • Where appropriate, bundle other station components in poor condition as part of refurbishment work.

D. EXPENDITURE PLAN

The below table summarizes the projected spending on the aggregate investment level. The costs in this investment are forecast based on scope and historical costs of station refurbishment projects and padmount distribution stations.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	49.9	47.7	32.3	35.4	35.6	200.9
Less Removals	5.1	6.2	3.8	3.1	3.5	21.8
Capital and Minor Fixed Assets	**44.8**	**41.5**	**28.5**	**32.3**	**32.1**	**179.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**44.8**	**41.5**	**28.5**	**32.3**	**32.1**	**179.1**

The factors which could impact station refurbishment project costs within this investment include:

- Number of transformer banks;
- Size of transformer;
- Number of station feeders;
- Primary and secondary voltage level;
- Station design;
- Replacing or upgrading of station structure;
- Extent of civil work;
- Grounding system design;
- Procurement of real estate; and
- Environmental remediation required at the distribution and regulating station.

E. ALTERNATIVES

Hydro One considered the following before selecting the recommended option.

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENTS

Wait for Distribution Station Equipment to Fail and Replace the Failed Components on a Reactive Basis.

This alternative is rejected for several reasons. Reactive management of stations would lead to degraded reliability for Hydro One's customers as a result of increases in station failures and the duration of outages (up to 21 hours based on Hydro One's experience with MUS's available). The reactive replacements would be limited to addressing only the failed component and would not address other components in deteriorated condition that are also at risk of failure. Over time, the volume of failures would increase under this approach, and the MUS and spare transformer fleet would run out of units to address these failures, thus leading to a significant risk in system reliability and potential outage durations of 48 hours or more.

ALTERNATIVE 2: PLANNED STATION REFURBISHMENTS *(RECOMMENDED)*

This alternative proactively addresses poor condition transformers and may include bundling of other poor condition components (such as station structure, MUS structures, fences, grounding systems, station service transformers, insulators and protection relays etc.) up to and including a full station refurbishment. Where required, this approach also allows the upgrading of the station to meet other needs such as load growth. Pad-mounted distribution stations are used to replace traditional stations where feasible as a lower cost alternative.

When this investment was presented through the customer engagement survey it revealed that residential customers tend to favour an accelerated pace, while commercial, industrial and LDA customers mainly supported the draft plan. As a result, this alternative was developed in response to the engagement results and is at a level between the accelerated and draft plans.

This alternative is recommended as it addresses needs identified at the station in the most cost-effective manner in order to maintain the reliability of supply, mitigate safety risk where present and responds to the customers' preference to address poor condition transformers at a pace between the draft and accelerated plans.

ALTERNATIVE 3: PLANNED STATION REFURBISHMENTS AT AN ACCELERATED PACE

This alternative is similar to Alternative 2 except for the pacing and expenditure of the investment. The accelerated pace will yield a higher total net investment cost through additional station refurbishments in the same timeframe.

This alternative was presented during customer engagement and was not fully supported by all customer segments. As a result, this alternative was not recommended.

F. EXECUTION RISK AND MITIGATION

The risks that can impact the completion of a station refurbishment project include the potential need to procure real estate to accommodate the station configuration, potential environmental remediation of the site and lands of Indigenous significance. These risks are mitigated by determining the requirements of the new station early in the project planning process, consulting with property owners and by requesting a land survey and environmental site survey before detailed design work has started.

APPENDIX A – DESCRIPTION OF INVESTMENTS

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2023	2024	2025	2026	2027
Brookside DS	SR-04.1	Convert 44:8.32kV 5MVA station to PDS with 2x3MVA units	3.1	0.0	0.0	0.0	0.0
Chesterville Bran DS	SR-04.2	Convert 44:4.16kV 2MVA station to PDS with 2x3MVA units	0.1	0.0	0.0	0.0	0.0
Chesterville DS #2	SR-04.3	Convert 44:4.16kV 3MVA station to PDS with 3MVA unit	0.1	0.0	0.0	0.0	0.0
Cobalt DS	SR-04.4	Refurbish 44:12.5kV 3MVA station to 7.5MVA unit on new site with electronic reclosers	2.5	0.0	0.0	0.0	0.0
Craighurst DS	SR-04.5	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit	0.9	0.0	0.0	0.0	0.0
Disputed Road RS	SR-04.6	Replace 27.6:27.6kV 25MVA transformer with 25MVA unit	2.9	0.0	0.0	0.0	0.0
Goodwood DS	SR-04.7	Refurbish 44:8.32kV 5MVA station to 7.5MVA unit	3.1	0.0	0.0	0.0	0.0
Kenora DS	SR-04.8	Replace 115:12.5kV 7.5MVA transformer with 7.5MVA unit	1.0	0.0	0.0	0.0	0.0
Killaloe DS	SR-04.9	Replace 44:12.5kV 6MVA transformer with 5MVA unit, electronic reclosers and SCADA	0.9	0.0	0.0	0.0	0.0
Millington DS	SR-04.10	Replace 44:8.32kV 5MVA transformer with 5MVA unit	1.0	0.0	0.0	0.0	0.0
Pointe Au Baril DS	SR-04.11	Replace 44:12.5kV 3MVA with 5MVA unit	1.4	0.0	0.0	0.0	0.0
Snow Road DS	SR-04.12	Replace 44:12.5kV 3MVA transformer with 5MVA unit	0.9	0.0	0.0	0.0	0.0
Stratford DS	SR-04.13	Replace 27.6:8.32kV 3MVA transformer with 5MVA unit	0.4	0.0	0.0	0.0	0.0
Stratford Easthp DS	SR-04.14	Refurbish 27.6:8.32kV 3MVA station to 10MVA unit with SCADA	3.1	0.0	0.0	0.0	0.0
Wolsey Lake DS	SR-04.15	Replace 44:12.5kV 6MVA transformer to 7.5MVA unit with electronic reclosers	1.0	0.0	0.0	0.0	0.0
Alex Kenyon West DS	SR-04.16	Replace 44:4.16kV 2MVA transformer with 5MVA unit	0.1	0.9	0.0	0.0	0.0
Belmont DS	SR-04.17	Refurbish 27.6:8.32kV 3.6MVA station with 5MVA unit	1.8	1.3	0.0	0.0	0.0
Berwick DS	SR-04.18	Convert 44:8.32kV 3MVA station to PDS with 2x3MVA	0.6	0.3	0.0	0.0	0.0
Brighton Pinnacle DS	SR-04.19	Refurbish 44:4.16kV 5MVA with 5MVA unit, electronic reclosers and SCADA	0.5	2.6	0.0	0.0	0.0
Brockvil Park DS	SR-04.20	Convert 44:4.16kV 5MVA station with breakers to PDS with 2x3MVA	0.0	1.1	0.0	0.0	0.0
Crozier DS	SR-04.21	Convert 44:25kV 2x6MVA station to PDS with 2x3MVA	0.0	1.0	0.0	0.0	0.0
Deseronto DS	SR-04.22	Replace 44:4.16kV 3MVA transformer with 5MVA unit, electronic reclosers and SCADA	0.1	1.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2023	2024	2025	2026	2027
Jellicoe DS #3	SR-04.23	Refurbish 115:12.5kV 1.5MVA station with 7.5MVA unit	0.0	3.2	0.0	0.0	0.0
Lily Lake DS	SR-04.24	Refurbish 44:8.32kV 2MVA station with 7.5MVA unit on new site	0.2	1.6	0.0	0.0	0.0
Owen Sound DS #2	SR-04.25	Convert 44:8.32kV 2MVA station to PDS 3MVA unit on new site with electronic reclosers	0.2	2.3	0.0	0.0	0.0
Richardson RS	SR-04.26	Replace 44:44kV 25MVA station with 25MVA unit with SCADA	2.8	0.3	0.0	0.0	0.0
Ringwood DS	SR-04.27	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit	0.0	1.0	0.0	0.0	0.0
Schreiber Winnipg DS	SR-04.28	Refurbish 115:12.5kV 6MVA station with 7.5MVA unit	0.0	3.2	0.0	0.0	0.0
Shelburn Andrew DS	SR-04.29	Convert 44:4.16kV 5MVA station to PDS 3MVA unit	0.0	3.2	0.0	0.0	0.0
Simcoe Ireland DS	SR-04.30	Refurbish 27.6:8.32kV 5MVA station with 5MVA unit	2.8	0.3	0.0	0.0	0.0
St.Thomas Union DS	SR-04.31	Replace 27.6:8.32kV 5MVA transformer with 5MVA unit	0.0	1.5	0.0	0.0	0.0
Stouffvil 10 Line DS	SR-04.32	Replace 44:8.32kV 5MVA transformer with 5MVA unit	0.1	1.0	0.0	0.0	0.0
Thamesville North DS	SR-04.33	Refurbish 27.6:8.32kV 5MVA station with 7.5MVA unit	0.0	3.2	0.0	0.0	0.0
Thorold Allanport DS	SR-04.34	Replace 27.6:4.16kV 5.4MVA transformer with 5MVA unit, electronic reclosers and SCADA	0.0	1.5	0.0	0.0	0.0
Thorold Ormond DS	SR-04.35	Refurbish 27.6:4.16kV 5.4MVA transformer with 5MVA unit, electronic reclosers and SCADA	2.3	0.8	0.0	0.0	0.0
Thorold Turner DS	SR-04.36	Refurbish 27.6:8.32kV 3.6MVA station with 5MVA unit, electronic reclosers and SCADA	2.8	0.3	0.0	0.0	0.0
Uxbridge DS #2	SR-04.37	Refurbish 44:8.32kV 5MVA transformer with 7.5MVA unit	2.6	0.5	0.0	0.0	0.0
Williamstown RS	SR-04.38	Replace 44:44kV 25MVA transformer with 25MVA unit	2.6	0.5	0.0	0.0	0.0
Woodland Beach DS	SR-04.39	Refurbish 44:8.32kV 5MVA station with 7.5MVA unit	1.5	1.6	0.0	0.0	0.0
Young JCT RS	SR-04.40	Replace 27.6:27.6kV 15MVA with 15MVA unit	0.1	0.6	0.0	0.0	0.0
Black Corners DS	SR-04.41	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit, electronic reclosers with SCADA	0.0	0.1	0.8	0.0	0.0
Brighton Division DS	SR-04.42	Convert 44:4.16kV 3MVA station to PDS 2x3MVA unit with electronic reclosers and SCADA	0.0	0.0	3.0	0.0	0.0

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2023	2024	2025	2026	2027
Brunelle DS	SR-04.43	Refurbish 44:8.32kV 5MVA station with 7.5MVA unit	0.0	2.9	0.3	0.0	0.0
Burford DS	SR-04.44	Convert 27.6:8.32kV 3.6MVA station to PDS 2.5MVA with additional real estate	0.0	0.0	1.5	0.0	0.0
Castleton DS	SR-04.45	Replace 44:8.32kV 5MVA transformer with 5MVA unit	0.0	0.1	0.8	0.0	0.0
Devlin DS	SR-04.46	Refurbish 44:12.5kV 2MVA station with 7.5MVA unit	0.0	0.0	3.2	0.0	0.0
Drumbo DS	SR-04.47	Replace 27.6:8.32kV 2MVA transformer with 5MVA unit	0.0	0.1	0.5	0.0	0.0
Emo DS	SR-04.48	Refurbish 44:12.5kV 3MVA station with 7.5MVA unit	0.0	0.0	3.2	0.0	0.9
Forest Jefferson DS	SR-04.49	Convert 27.6:8.32kV 3.6MVA station to PDS 2x3MVA unit	0.0	0.4	1.8	0.0	0.0
Forest McNab DS	SR-04.50	Convert 27.6:4.16kV 5.6MVA station to PDS 2x3MVA unit with electronic reclosers	0.0	0.4	1.8	0.0	0.0
Guthrie DS	SR-04.51	Convert 44:8.32kV 3MVA station to PDS 3x3MVA unit	0.0	0.2	1.6	0.0	0.0
Kemptville West DS	SR-04.52	Replace 44:8.32kV 5MVA 7.5MVA unit with electronic recloser and SCADA	0.0	0.0	0.9	0.0	0.0
Shedden DS	SR-04.53	Replace 27.6:8.32kV 3.6MVA transformer with 7.5MVA unit	0.0	0.0	1.0	0.0	0.0
Thorold Front DS	SR-04.54	Replace 13.8:4.16kV 5.4MVA 5MVA unit with electronic recloser and SCADA	0.0	0.0	1.0	0.0	0.0
Vanastra DS	SR-04.55	Refurbish 27.6:8.32kV 3.6MVA station to 7.5MVA unit with electronic recloser and SCADA	0.0	0.8	2.2	0.0	0.0
Cameron DS	SR-04.56	Replace 44:12.5kV 6MVA transformer with 7.5MVA unit	0.0	0.0	0.0	1.0	0.0
Espanola DS	SR-04.57	Replace 44:12.5kV 6MVA transformer with 7.5MVA unit	0.0	0.0	0.1	0.8	0.0
Grand Valley DS #2	SR-04.58	Replace 44:12.5kV 3MVA transformer with 7.5MVA unit, electronic reclosers and SCADA	0.0	0.1	0.8	0.1	0.0
Lucan Market DS 8kV	SR-04.59	Replace 27.6:8.32kV 3.6MVA transformer with 5MVA unit	0.0	0.0	0.1	0.8	0.0
Nakina DS	SR-04.60	Refurbish 44:12.5kV 3MVA station to 7.5MVA unit with electronic reclosers and SCADA	0.0	0.0	0.3	3.0	0.0
Red Rock DS	SR-04.61	Refurbish 115:12.5kV 6.24MVA station to 7.5MVA unit	0.0	0.1	0.9	3.2	0.0
Russell DS	SR-04.62	Replace 115:8.32kV 12MVA transformer with 15MVA	0.0	0.0	0.0	1.2	0.0
Shabaqua DS	SR-04.63	Refurbish 115:25kV 6MVA and 25:12.5kV 2MVA station with 115:25kV 7.5MVA unit	0.0	0.0	0.3	4.6	0.0

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2023	2024	2025	2026	2027
Thedford DS	SR-04.64	Replace 27.6:8.32kV 3.6MVA transformer with 5MVA	0.0	0.0	0.1	0.8	0.0
Virginiatown DS	SR-04.65	Convert 44:4.16kV 2MVA station to PDS 3MVA unit on greenfield site	0.0	0.0	0.2	2.9	0.0
Washago DS	SR-04.66	Refurbish 44:8.32kV 5MVA transformer with 7.5MVA unit	0.0	0.0	0.0	3.3	0.0
Wellington DS	SR-04.67	Replace 44:8.32kV 5MVA transformer with 5MVA with SCADA	0.0	0.0	0.1	0.8	0.0
Aguasabon DS	SR-04.68	Refurbish 13.8:12.5kV 6MVA transformer with 12.5MVA unit	0.0	0.0	0.0	0.0	3.3
Colborne DS #2	SR-04.69	Replace 44:8.32kV 3MVA station with 7.5MVA unit and electronic reclosers	0.0	0.0	0.0	0.3	1.1
Coldstream DS	SR-04.70	Replace 27.6:8.32kV 5MVA with 5MVA unit	0.0	0.0	0.1	0.8	0.2
Dack DS	SR-04.71	Convert 44:12.5kV 3MVA station to PDS 3MVA unit	0.0	0.0	0.0	0.2	1.1
Ennismore DS	SR-04.72	Replace 44:8.32kV 5MVA transformer with 5MVA unit	0.0	0.0	0.0	0.1	0.0
Haycroft DS	SR-04.73	Replace 27.6:8.32kV 5MVA transformer with 7.5MVA unit	0.0	0.0	0.0	0.0	0.6
Hinchinbrooke DS	SR-04.74	Replace 115:12.5kV 7.2MVA transformer with 7.5MVA unit	0.0	0.0	0.0	0.1	1.0
Holland Centre RS	SR-04.75	Replace 44:44kV 15MVA transformer with 44MVA unit	0.0	0.0	0.0	0.6	0.3
Hornepayne DS	SR-04.76	Refurbish 44:4.16kV 10MVA station with 15MVA	0.0	0.0	0.0	2.2	1.1
Kimberley DS	SR-04.77	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit	0.0	0.0	0.0	0.1	1.2
Longlac East DS	SR-04.78	Refurbish 44:12.5kV 3MVA station to 7.5MVA unit	0.0	0.0	0.0	0.3	2.9
Maxville Prince DS	SR-04.79	Refurbish 44:4.16kV 2MVA station with 5MVA unit	0.0	0.0	0.0	0.1	0.8
McGregor DS	SR-04.80	Replace 27.6:8.32kV 5MVA transformer with 7.5MVA unit	0.0	0.0	0.1	0.6	0.3
Napanee DS #2	SR-04.81	Convert 44:8.32kV 5MVA station to PDS 2x3MVA units with electronic reclosers and SCADA	0.0	0.0	0.0	0.1	1.0
Picton Disraeli DS	SR-04.82	Replace 44:4.16kV 5MVA with breakers to 5MVA unit with electronic reclosers and SCADA	0.0	0.0	0.0	0.4	0.5
Picton DS	SR-04.83	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit, electronic reclosers and SCADA	0.0	0.0	0.0	0.1	1.0
Port Lambton DS	SR-04.84	Replace 27.6:8.32kV 5MVA transformer with 7.5MVA unit	0.0	0.0	0.1	0.6	0.3
Rainy River DS	SR-04.85	Convert 44:8.32kV 3MVA station to PDS 3MVA unit	0.0	0.0	0.0	0.3	0.8

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2023	**2024**	**2025**	**2026**	**2027**
Reach Road RS	SR-04.86	Replace 44:44kV 25MVA transformer with 25MVA unit	0.0	0.0	0.1	1.0	0.5
Rondeau DS	SR-04.87	Convert 27.6:8.32kV 3MVA station to PDS 3x2.5MVA unit with additional real estate	0.0	0.0	0.1	0.6	0.2
Rutherglen DS	SR-04.88	Convert 44:12.5kV 2MVA station to PDS 3MVA unit	0.0	0.0	0.0	0.2	3.3
Sleeman DS	SR-04.89	Refurbish 44:12.5 3MVA and 44:25kV 6MVA to 44:25kV 12.5MVA unit	0.0	0.0	0.0	0.3	4.7
Springvale DS	SR-04.90	Replace 27.6:8.32kV 5MVA transformer with 5MVA unit	0.0	0.0	0.0	0.1	1.0
Stardale DS	SR-04.91	Replace 44:8.32kV 5MVA station to 7.5MVA with electronic reclosers and SCADA	0.0	0.0	0.0	0.0	0.1
Whitedog DS	SR-04.92	Refurbish 13.8:12.5kV 2MVA station with 5MVA unit	0.0	0.0	0.0	0.2	2.9
Other Projects (<$1M)			1.3	1.5	1.5	0.5	1.0
Total			**44.8**	**41.5**	**28.5**	**32.3**	**32.1**

D-SR-05	DISTRIBUTION LINES TROUBLE CALL AND STORM DAMAGE RESPONSE PROGRAM
Primary Trigger:	Asset Failure or High Risk of Failure
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	106.0	108.1	110.3	112.5	114.7	551.7

Summary:

This investment involves the emergency replacement of distribution lines assets because they have either failed or have been determined to pose an immediate safety hazard. The primary trigger of the investment is demand-driven asset failure. The investment is required to restore systems to normal operation and to maintain reliability and safety.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is needed to respond to service interruptions or other system deficiencies on an urgent basis in compliance with the Distribution System Code.

A number of situations may arise that require immediate response by Hydro One Distribution personnel. Severe weather or asset failures may result in a service interruption. Regular patrols and inspections may identify damaged or failed distribution assets that pose a safety hazard. Upon such occurrences or discoveries, Hydro One Distribution field crews must be dispatched to promptly assess and resolve any urgent deficiency. As an example, Figure 1 below provides various photos of severe weather damage to distribution line assets. During storm conditions, poles that fail can sometimes trigger cascading failures, which result in the failure of a larger number of distribution system assets (see Figure 1d and 1e below).

Figure 1: Examples of Storm Damage

Figure 2 below shows the actual program expenditures over the 2016 to 2020 period (as further described in Section B below). There is an overall increasing trend over this period. The largest contributor to the annual volatility in demand relates to storm damage, which, as explained below, involves the restoration of service interruptions caused by adverse weather conditions. Notably, there were a higher number of more severe storms in 2018, which required a significant increase in spending.

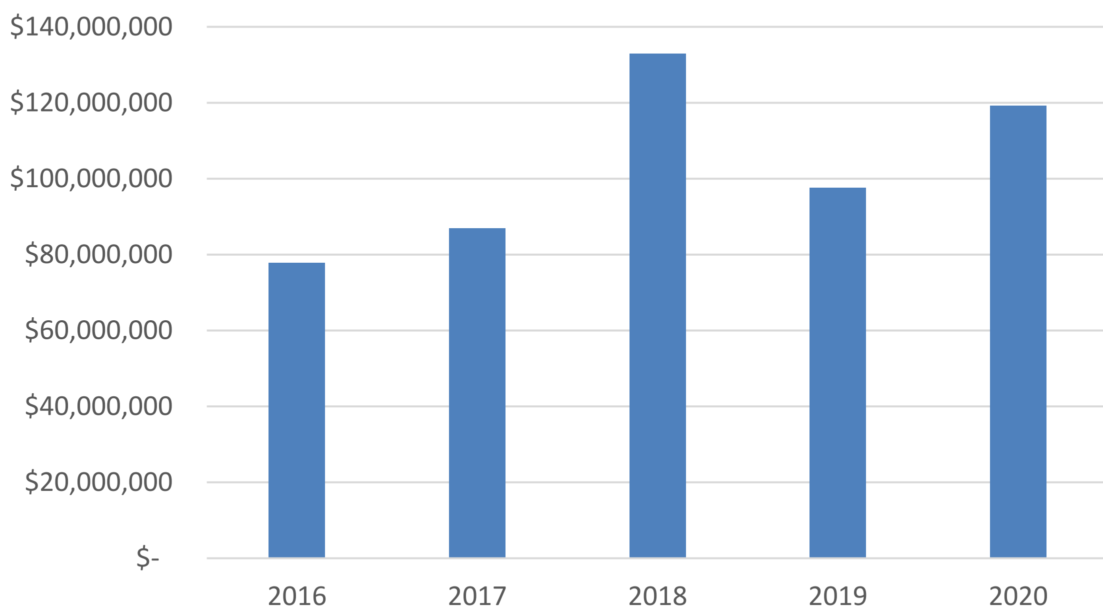

Figure 2: Trouble/Storm Program Expenditures (2016-2020)

B. INVESTMENT DESCRIPTION

Hydro One's distribution system serves about 1.4 million customers and spans a vast geographic territory. This demand program encompasses the capital costs for responding to trouble calls, storm damage, power interruptions, and other situations that pose reliability or safety risks and require immediate attention. Planned expenditures for this demand program are projected from historical costs.

The trouble call and storm damage response program includes the following activities:

- Emergency pole and equipment replacements.
- Emergency submarine and underground cable replacements.
- Storm damage response to resolve service interruptions caused by adverse weather conditions. This sub-program covers all costs for the response and replacement of failed assets (e.g., poles, conductors, transformers, reclosers, regulators and switches) caused by major storms.
- Post-trouble response to implement permanent solutions to any temporary repairs that were required during an emergency or a service interruption. Through this sub-program, Hydro One restores the affected part of the power system to original operations after the initial failure and emergency fix. Work is limited to correcting the area that is directly affected by the failure. Key work activities commonly include pole and transformer replacements.
- Damage claims, including payment for third-party damage that Hydro One Distribution cannot recover. Key work activities most commonly include pole replacement from motor vehicle accidents and conductor replacement from dig-ins or accidental contact.

C. OUTCOMES

The trouble call and storm damage program will result in:

- Ensuring Hydro One Distribution's ability to respond to trouble calls and service interruptions.
- Mitigating reliability and safety risks during and after emergency events.
- Complying with regulatory requirements with respect to timely incident response and restoration of supply.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Minimize customer interruption duration by carrying out demand work in a timely manner. • Address potential public safety hazards.
Operational Effectiveness	• Maintain the safe operation and performance of the distribution system by addressing immediate reliability and safety risks.
Public Policy Responsiveness	• Comply with Section 7 of the Distribution System Code to ensure timely response to storm damage, deficiencies and system outages

D. EXPENDITURE PLAN

The forecast expenditures for this demand program are projected from historical costs and trends. Storm response expenditures are based on an inflation-adjusted average of annual expenditures since 2005, with "outlier" years of unusually high expenditures (i.e. due to more severe storms) removed from the forecast – namely, 2006, 2013, and 2018. The expenditures for other categories of activities are guided by an inflation adjusted three year historical average.

Table 2 below summarizes projected program spending for 2023-2027. The forecast expenditures for this demand program are projected from historical costs and trends. Storm response expenditures are based on an inflation-adjusted average of annual expenditures since 2005, with "outlier" years of unusually high expenditures (i.e. due to more severe storms) removed from the forecast – namely, 2006, 2013, and 2018. The expenditures for other categories of activities are guided by an inflation adjusted three year historical average.

Table 2 – Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	127.4	130.0	132.6	135.2	138.0	663.2
Less Removals	15.3	15.6	15.9	16.2	16.6	79.6
Capital and Minor Fixed Assets	**112.2**	**114.4**	**116.7**	**119.0**	**121.4**	**583.6**
Less Capital Contributions	6.1	6.3	6.4	6.5	6.7	32.0
Net Investment Cost	**106.0**	**108.1**	**110.3**	**112.5**	**114.7**	**551.7**

The factors affecting the cost of the investment include:

- The amount of trouble call issues that arise in a given year.
- The scope of the work required to fix particular issues.
- The volume and severity of weather events across the province in a given year.

E. ALTERNATIVES

No alternatives were considered, since failure to quickly respond to service interruptions or other urgent situations involving failed or imminently failing assets would not be compatible with Hydro One’s service obligations under the Distribution System Code and would result in unacceptable reliability and safety risks.

F. EXECUTION RISK AND MITIGATION

Hydro One successfully restores power to hundreds of thousands of customers every year, and therefore does not anticipate any major risks to this program. However, where the volume of restoration work exceeds resources due to major weather events, restoration is prioritized based on the greatest benefit to the most customers.

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D-SR-06	Distribution Lines PCB Equipment Replacement Program
Primary Trigger:	Obsolescence/Compliance
OEB RRF Outcomes:	Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	9.4	9.5	9.5	0.0	0.0	28.3

Summary:

This investment involves the replacement of oil filled distribution lines equipment that exceed federal regulatory thresholds for PCB. The primary trigger of the investment is a statutory requirement to remove all equipment exceeding 50 ppm PCB by the end of 2025. The investment is expected to mitigate health and safety risks associated with PCB contaminated line equipment and ensure compliance with federal legislation.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Oil-filled equipment manufactured prior to 1981 may contain chemical compounds known as polychlorinated biphenyls (PCBs). This investment is needed to manage the removal of line equipment containing PCBs in compliance with *Canadian Environmental Protection Act, 1999* regulation SOR/2008-273 (PCB Regulations). The legislation mandates the removal of all oil filled equipment whose insulating oil contains greater than 50 ppm of PCBs by the end of 2025. Failure to complete the mandated PCB elimination by 2025 would result in non-compliance penalties.

The removal of PCB contaminated equipment is required to ensure health and safety risks are mitigated and ensure compliance with the PCB Regulations.

B. INVESTMENT DESCRIPTION

This investment addresses the removal and replacement of Hydro One's distribution line oil-filled equipment whose insulating oil contains PCB contamination levels greater than 50 ppm. Pole top transformers are the primary source for potential PCB contamination in Hydro One's distribution line equipment. All pole top transformers manufactured prior to 1981 will require oil sampling and PCB analysis as described in Exhibit E-03-02, subsection 2.2.5, to determine their PCB content. Of the approximately 460,000 pole top transformers in Hydro One's distribution system, approximately 17% were manufactured prior to 1981. From past experience with PCB testing, Hydro One forecasts that approximately 8% of these transformers will exceed the 50 ppm threshold or cannot be tested and will ultimately require replacement.

Capacitors make up a small amount of potential PCB contamination with a population of approximately 2,800 units. Capacitor units cannot be tested for PCBs without causing them significant damage, therefore all capacitors manufactured before 1981 require replacement. The specific units to be replaced are identified through distribution line patrols or the PCB equipment inspection program. The replacement of equipment lags the PCB testing program by one year, allowing time for the identification of contaminated equipment and the planning required to replace them with minimal impact to customers.

Hydro One Distribution's plan is to replace equipment at the rate outlined below. This rate of replacement ensures the program will be complete by the 2025 deadline set out by the PCB Regulations.

Table 1 - Volume of Equipment Replacement

Year	2023	2024	2025	2026	2027
Number of Oil Filled Equipment Replacements	1,439	1,362	1,268	-	-

C. OUTCOMES

The lines PCB equipment replacement program will result in:

- Mitigating health and safety risks associated with PCB contaminated line equipment, and
- Compliance with the PCB Regulations.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcome Summary

Operational Effectiveness	• Mitigate potential health and safety hazards associated with PCB oil contamination levels in lines equipment.
Public Policy Responsiveness	• Comply with Federal PCB Regulation (SOR/2008-273) to remove all oil filled equipment with PCB contamination > 50 ppm by 2025.

D. EXPENDITURE PLAN

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	10.7	10.7	10.7	0.0	0.0	32.2
Less Removals	1.3	1.3	1.3	0.0	0.0	3.9
Capital and Minor Fixed Assets	**9.4**	**9.5**	**9.5**	**0.0**	**0.0**	**28.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**9.4**	**9.5**	**9.5**	**0.0**	**0.0**	**28.3**

The factors affecting the cost of the investment include:

- The number of equipment forecast for replacement – The forecast level of equipment replacement is based on a projection of the past results of the program. Results show that approximately 17% of equipment is older than 1981 and will require sampling and that approximately 8% of the equipment sampled will need to be replaced.

- The number of opportunistic equipment replacements – Historically, Hydro One has replaced PCB contaminated equipment in conjunction with other work. For example, if the Company were replacing poles as part of a system renewal project, it would replace the transformers as well which addresses the PCB risk with only the incremental material cost of the transformer. As the 2025 deadline approaches, the amount of lower cost opportunistic replacements decreases since the total amount of equipment needing replacement decreases. The decline in replacements for the 2023-2027 period is offset by inflation and a higher unit cost for replacement, producing a constant level of expenditure, year-over-year.

E. ALTERNATIVES

No alternatives are considered, since failure to remove PCB contaminated line equipment would place Hydro One Distribution in violation of the PCB Regulations.

F. EXECUTION RISK AND MITIGATION

The equipment targeted for replacement lags the PCB testing program. The risk to this program being completed as planned is mainly if the testing program discovers a higher proportion of contamination relative to historic years. Hydro One will manage this risk through our work execution strategy, as described in DSP Section 3.10.

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D-SR-07	POLE SUSTAINMENT PROGRAM
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	107.9	110.6	112.4	114.9	116.8	562.6

Summary:

This investment involves the planned replacement and chemical and mechanical refurbishment of distribution poles where they have been assessed to be in poor condition or require ground line retreatment. The primary trigger of the investment is asset condition. By proactively targeting poor condition poles that pose higher reliability risk, this investment is expected to help maintain reliable operation of the distribution system and reduce the number of potential interruptions to customers. Additionally, chemically retreating poles proactively will result in mitigation of ground line rot and prevent further deterioration of poles at the ground line which is expected to extend pole life.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

The structural integrity of a distribution line is largely dependent on the poles that support the line. Hydro One owns and maintains approximately 1.6 million poles, 99.3% of which are wood poles. Poles are critical to the operations of the distribution system, as structurally sound poles are necessary to support conductors and other overhead assets (transformers, switches, reclosers etc.) and to ensure clearance from live conductors in publicly accessible areas.

The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, and other factors that erode their structural integrity. Once a pole has deteriorated to poor condition, it is deemed to be end-of-life and poses a high risk of failure. Pole failures can have a significant impact on customer reliability, which is a risk that can be mitigated through proactive planning before interruptions occur. Hydro One inspects and tests its pole population to determine asset condition, and prioritizes poor-condition poles with the highest reliability risk for planned refurbishment or replacement.

POLES IN POOR CONDITION

As outlined in DSP Section 3.2, approximately 79,000 poles are in poor condition and at high risk of failure. During the plan period, it is expected that an additional 50,000 poles will be added to the poor category due to deteriorating condition.

Poles are required to be inspected every six years in rural areas and every three years in urban areas as specified in the Distribution System Code, Appendix C. In 2019, Hydro One's pole inspection program was combined with its forestry planning process. This means that the structures are inspected in line with Forestry's Optimal Cycle Protocol (see Exhibit E-03-02). These inspections are primarily intended to identify visual deficiencies on the pole, including woodpecker holes, mechanical surface damage, surface rot, severe leaning, broken poles, or any other potential safety issues that must be addressed immediately. As an example, Figure 1 below shows three types of pole-related defects (in order from left to right): a woodpecker nesting hole, ground-line rot, and pole damage.

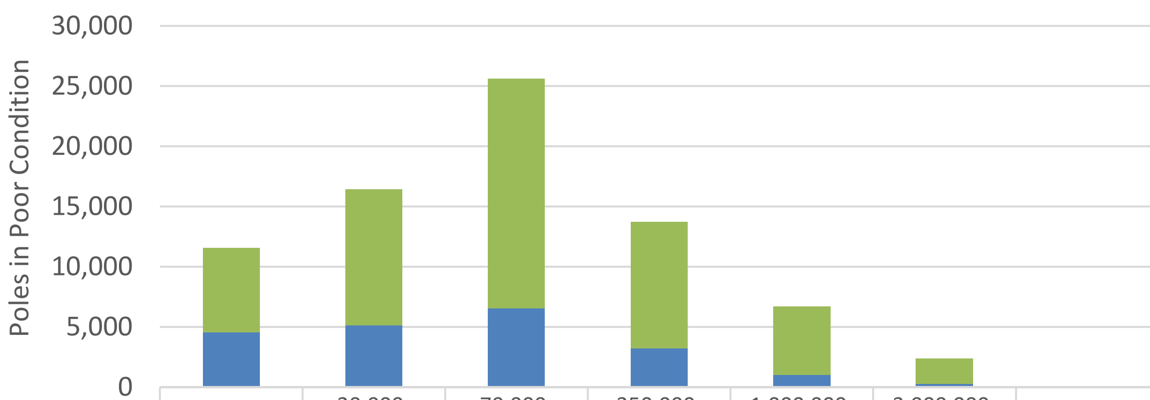
Figure 1: Examples of Poor-Condition Poles

Defects identified on the lines are also recorded during inspections, including damaged cross arms, insulator defects, and missing guys. Additionally, poor condition poles include a subset of 17,000 red pine poles that were found to not be fully treated for preservation to the Canadian Standards Association (CSA) minimum requirements and that have demonstrated premature rot and degradation.

In addition to visual inspections to assess pole condition and potential refurbishment options, Hydro One has begun the process of collecting supplementary condition data through a Test and Treat program starting in 2020, as discussed further below. This process is performed on a less frequent cycle than visual inspections, and only at the ground line. It involves proactively testing poles to assess their condition and chemically retreating poles at the ground line to extend their life. The Test and Treat program involves taking detailed measurements of the pole and the size of the damage, including drilling into the pole to assess the amount of internal rot. These measurements are used to calculate the remaining strength of the pole, expressed as a percentage of its design strength. This helps identify additional poles that require replacement (in addition to poor condition poles identified through visual inspections) or that can be mechanically refurbished.

RELIABILITY

Poles have the potential to impact thousands of customers when a pole near the beginning of the feeder fails or just a few customers if a pole near the end of the feeder fails. Customer minutes interrupted (CMI) is a metric which takes the total number of customers impacted by an outage and multiplies it by the duration of the interruption in minutes. For example, if a pole fails that supplies 100 downstream customers and the outage lasts 300 minutes, the CMI would be 30,000. Using historic outage times and downstream customer counts, a similar calculation is completed for each pole that requires replacement or refurbishment to determine the CMI impact if the pole in poor condition were to fail. In this manner, the CMI impact is used to inform the reliability risk associated with poor condition poles, and poles are prioritized for replacement or refurbishment based on their reliability risk. The following graph shows the potential CMI impact of the poles currently in need of replacement or refurbishment.



	<20,000	20,000-70,000	70,000-350,000	350,000-1,000,000	1,000,000-3,000,000	3,000,000-7,000,000	>7,000,000
Replace	6,994	11,294	19,033	10,528	5,673	2,102	49
Refurbish	4,559	5,147	6,556	3,210	1,031	276	

CMI

Figure 2: Poles in Poor Condition by CMI

On average, when a pole causes a forced outage it will result in a 9.0 hour interruption (excluding force majeure or FM events). When a pole requires a planned outage to replace, the average outage duration is 2.4 hours. In addition, many planned pole replacements can be completed without any customer interruption at all. Proactive replacement of poles avoids the otherwise prolonged outage durations associated with a run-to-fail approach.

Figure 3 provides the historical number of interruptions attributed to pole failures (excluding FM events). It shows an increasing trend of interruptions in recent years. At the same time, the contribution of pole failures to the overall impact of customer interruptions has remained relatively flat in the last 10 years (see Figure 4 and Figure 5 below). This indicates that fewer customers are being impacted on average per pole failure – a result that is consistent with the expected outcome of Hydro One's ongoing efforts to prioritize poles with the highest impact to reliability.

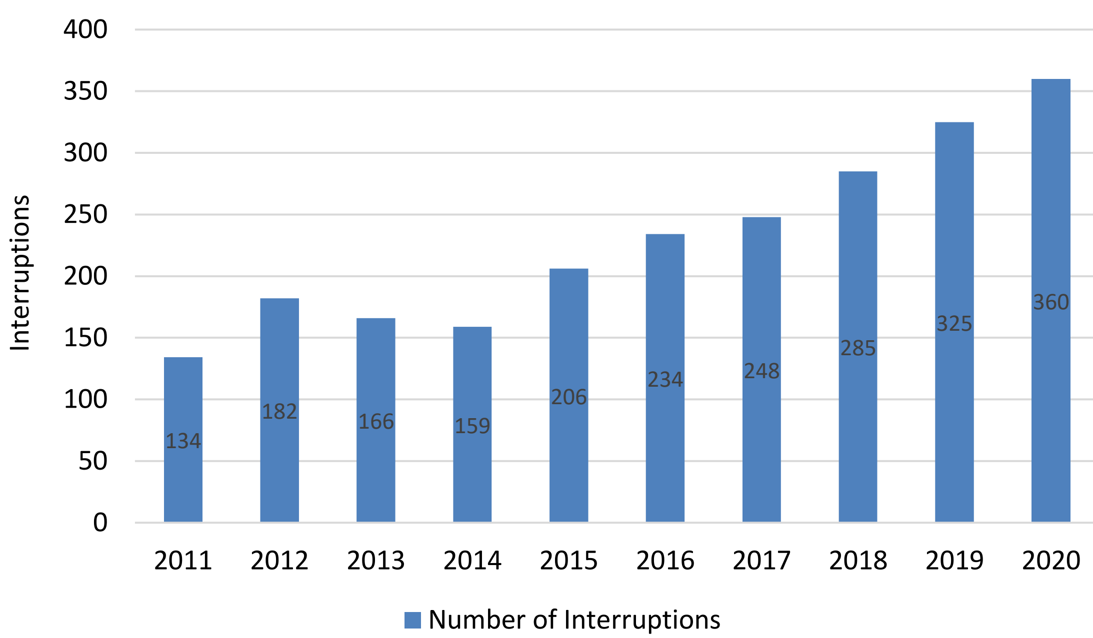


Figure 3: Pole Caused Interruptions Excluding FM

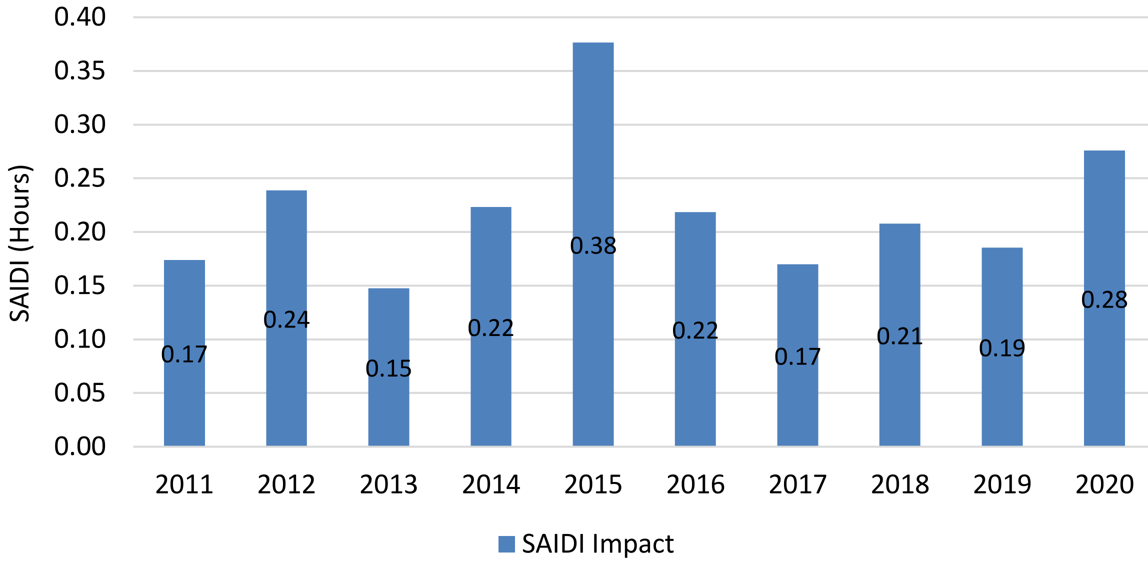


Figure 4: Pole Caused SAIDI (Excluding FM)

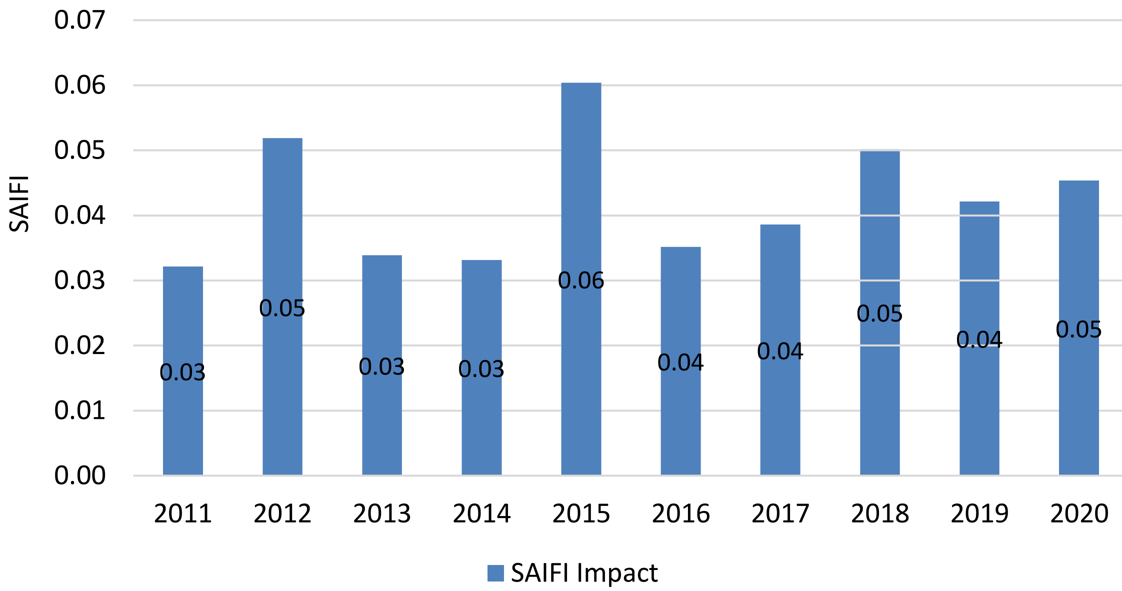


Figure 5: Pole Caused SAIFI Excluding FM

SAFETY

As poles are usually in publicly accessible spaces, there is potential for a pole failure to impact public safety. By replacing or refurbishing poles proactively through the planned sustainment program, this safety risk is reduced. When an immediate public or worker safety risk arises, those poles are addressed either through the trouble program or through the appropriate work procedures.

POLE MANAGEMENT OPTIONS

The Pole Sustainment Program consists of three investment approaches: Test and Treat, Pole Refurbishment, and Pole Replacement. The Test and Treat investment identifies poles that require replacement or mechanical refurbishment and will chemically refurbish the poles by treating the poles at the ground line. The Pole Refurbishment investment will restore mechanical strength by adding bracing to poles that have been determined to be in poor condition and which meet the criteria for refurbishment. The Pole Replacement investment will replace poles in poor condition that cannot be refurbished.

B. INVESTMENT DESCRIPTION

Pole sustainment investments are province-wide and impact sites across Hydro One’s service territory. The Test and Treat investment will proactively test and chemically refurbish 103,000 poles per year on an approximately 15-year cycle, the Structural Refurbishment investment will structurally support 2,800 poles per year, and the Pole Replacement investment will replace 10,300 poles per year.

TEST AND TREAT

The Test and Treat investment proactively assesses the condition of poles and chemically refurbishes them through ground line treatment. The testing process involves visually assessing the exterior condition of the pole, drilling into the pole to measure the remaining strength, and inserting a copper borate retreatment product to extend the life of the pole. The data collected from this activity will supplement pole condition data that is acquired through visual inspections and help identify additional poles that require replacement or that can be mechanically refurbished. This program was a recommendation from the previous benchmarking study.

POLE REFURBISHMENT

The Pole Refurbishment investment installs structural supports on poor-condition poles as an alternative to replacement. Poles that qualify for refurbishment include poles where the damage is isolated to the ground line, poles that are on road, and poles that do not have third-party attachments. Poles are prioritized based on their reliability risk. This program was a recommendation from the previous benchmarking study.

POLE REPLACEMENT

The Pole Replacement investment addresses the replacement of poles that are at the end of their life which cannot be refurbished. Poles are prioritized based on their reliability risk.

PACING AND BUNDLING

Hydro One is sensitive to customer needs and will manage the population of poles in poor condition that have the highest potential impact on reliability risk over the five-year plan, so as to reduce cost impacts to customers. There is currently a large number of poles in poor condition that are at high risk of failure, and it is forecasted that the proposed investment will reduce this number to approximately 62,000 poles over the planning period. The table below outlines the planned volume of poles in the proposed investment throughout the five-year period.

Table 1 - Planned Volumes

	2023	2024	2025	2026	2027
Test and Treat	103,000	103,000	103,000	103,000	103,000
Pole Refurbishment	2,800	2,800	2,800	2,800	2,800
Pole Replacement	10,300	10,300	10,300	10,300	10,300

The proposed plan is in line with the pacing preferred by Hydro One's customers (see SPF Section 1.6, Attachment 1) and will replace or refurbish approximately 13,100 poles per year, or approximately 65,500 poles over the five year period. The proposed plan will only address a subset of poor condition poles based on their reliability risk.

The following graph shows the total number of poles in poor condition slightly decreasing over the plan. The number of higher reliability risk poles will decrease significantly over the plan. The number of lower reliability risk poles will increase over the plan.

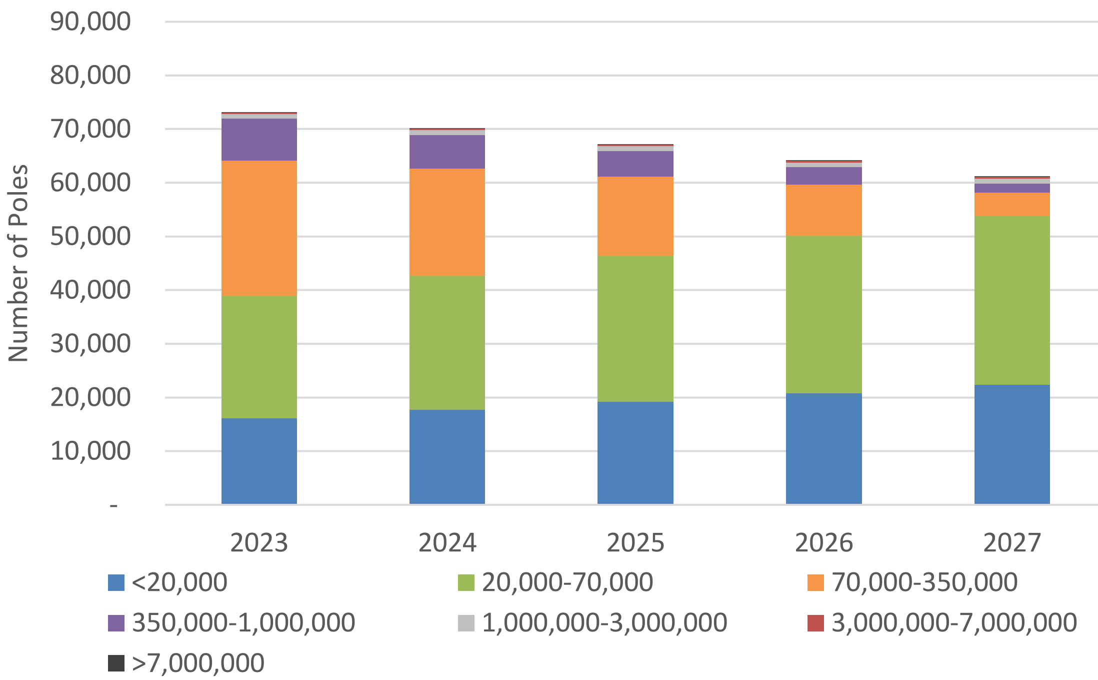


Figure 6: Poles in Poor Condition Over The Planning Period by CMI

Depending on the types of poles requiring replacement (i.e., pole height, pole class, number of circuits, etc.) and the accessibility conditions of the area, the cost of replacement can vary. Where possible, the efficiency of this investment is improved by bundling poles and replacing or refurbishing poles in close proximity to each other.

C. OUTCOMES

The pole sustainment program will result in:

- Addressing poor condition poles that pose higher reliability risk in order to help maintain reliability and reduce the number of potential interruptions to customers
- Refurbishment of poles where possible as a lower cost alternative to pole replacement
- Chemically retreating poles proactively to prevent further deterioration at the ground line which is expected to extend pole life.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcome Summary

Customer Focus	• Reduce the number of potential interruptions to customers by proactively replacing or refurbishing wood poles prior to failure.
Operational Effectiveness	• Maintain reliable operation of the distribution system by proactively targeting and addressing poor-condition poles that pose the highest reliability risk. • Extend pole life through chemically retreating poles to mitigate ground line rot and prevent further deterioration at the ground line.

D. EXPENDITURE PLAN

Costs are based on unit-price estimates that are set based on recent historic spending and the volume of work projected for the planning period. Gross cost per pole replaced is an outcome measurement of this rate application. More details on the replacement investment unit cost can be found in DSP Section 3.5.

Table 3 below summarizes the projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	122.6	125.7	127.7	130.6	132.7	639.3
Less Removals	14.7	15.1	15.3	15.7	15.9	76.7
Capital and Minor Fixed Assets	**107.9**	**110.6**	**112.4**	**114.9**	**116.8**	**562.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**107.9**	**110.6**	**112.4**	**114.9**	**116.8**	**562.6**

The factors influencing the cost of the investment include:

- The types of poles requiring replacement (i.e., pole height, pole class, number of circuits, etc.);
- The location accessibility conditions of the area in which the poles are being replaced (accessing off-road locations is typically more costly due to the use of specialized equipment); and
- The cost of material.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: REACTIVE REPLACEMENTS

This alternative entails a reactive replacement approach, whereby failed poles would be addressed solely through the trouble program (ISD D-SR-05). Under this alternative, Hydro One would not test and treat poles, structurally refurbish poles, or proactively replace poles. Instead, pole condition will be monitored through the safety patrols being performed as part of the vegetation management program, and poles that have failed or have the potential to cause an immediate public safety issue will be replaced on a reactive basis. This alternative is rejected as reactive management of poles will lead to increased failures resulting in degraded reliability for Hydro One’s customers and an overall increased risk to public safety.

ALTERNATIVE 2: ADDRESS HIGHEST-RISK POLES (RECOMMENDED)

Under this preferred alternative, Hydro One Distribution will test and treat poles on a 15-year cycle, structurally refurbish approximately 2,800 poles per year, and replace approximately 10,300 poles per year. This alternative will effectively manage the poles that pose the highest risk to customer reliability and the volumes of poles addressed are in line with the customer engagement results. Under this alternative, poles with the lowest potential impact on customer reliability will be replaced reactively if they were to fail. This alternative is recommended because it balances risks and costs and is in line with customer preferences.

ALTERNATIVE 3: ACCELERATED REPLACEMENT

This alternative will test and treat poles on a 15-year cycle, structurally refurbish 4,000 poles per year, and replace 16,000 poles per year. This plan would address a higher population of poor-condition poles during the planning period. This alternative is rejected as it was presented during customer engagement, and most customers did not show a preference to replace poles at an accelerated rate.

F. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Investment include access to the assets depending on the season, and equipment outage availability. These risks are mitigated through extensive planning, scheduling, and outage coordination across lines of business and stakeholders. In the event a necessary outage cannot be obtained, the order of pole replacements will be adjusted as appropriate to ensure that program work execution is not disrupted.

D-SR-08	DISTRIBUTION LINES MINOR COMPONENT REPLACEMENT
Primary Trigger:	Obsolescence/Compliance
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	12.4	14.5	13.5	8.6	7.1	56.2

Summary:

This investment involves the replacement of a number of minor distribution lines components that are not specifically addressed under other lines-related distribution capital investments. This investment includes the replacement of cross arms in poor condition, the replacement of substandard and obsolete transformers, the installation of bird nest platforms, and the replacement of failed sentinel lights. The triggers of this investment are condition (in the case of cross arms), obsolescence (in the case of substandard transformers), and compliance (in the case of nest platforms and sentinel lights). This investment is expected to improve reliability and meet Hydro One's obligations with respect to the affected assets.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One's distribution system includes approximately 123,000 circuit kilometers of primary lines across the province. These lines are the primary means by which electricity is delivered to distribution customers.

Hydro One performs line patrols to assess the condition of a large variety of components on these distribution lines. These condition assessments have identified a number of line components that, due to their condition have reached end of life. Additionally, there is a population of line components on the distribution system that are obsolete or that pose safety or environmental risks. Hydro One must replace or refurbish these components to mitigate these risks and/or to maintain reliability of the system.

Planned replacements and refurbishments of line components in poor condition are primarily addressed via a number of larger capital investments, as described in D-SR-06 (equipment containing polychlorinated biphenyls, or PCBs), D-SR-07 (poles), D-SR-09 (submarine cables), and D-SR-10 (distribution lines sustainment initiatives). Additionally, component issues that are suitable for maintenance or corrective actions are addressed through OM&A expenditures.

Aside from these capital investments and OM&A expenditures, there remains a need to address a number of other line components. This 'Distribution Lines Minor Component Replacement Program' addresses these specific operational risks and/or customer service obligations. These line components include:

- Cross arms;
- Substandard transformers;
- Nest platforms; and
- Sentinel lights.

This investment summary document describes these other capital component replacement investments in more detail.

CROSS ARMS

Overhead conductors are often supported by cross members known as “cross arms”. Cross arms are typically made of wood, although composite and steel cross arms may be used when increased strength is required. Cross arms are visually inspected on a regular basis, and broken, cracked, or otherwise damaged arms are identified for replacement.

Approximately 20,000 cross arms (out of a total of 500,000) are identified as being in poor condition. Cross arms in poor condition have a higher risk of failure, which would typically result in a direct reliability impact to downstream customers. Cross-arm failures resulting in outages have an average reliability impact of approximately 100,000 customer minutes interrupted (CMI) per outage – though in the worst cases, a cross-arm failure can result in more than 1,000,000 CMI per outage. As a recent example, in 2020, a cross-arm failure in the Bancroft area led to a three-hour outage impacting 2,500 customers (resulting in 450,000 in CMI).

Figure 1 provides the historical number of interruptions attributed to cross-arm failures (excluding *force majeure* or FM events), showing an increasing trend of interruptions in recent years. At the same time, the customer impact due to cross-arm failures has declined since 2018. This indicates that fewer customers are being impacted per cross-arm failure – a result that is consistent with the expected outcome of Hydro One’s ongoing efforts to address cross arms impacting the highest number of downstream customers.

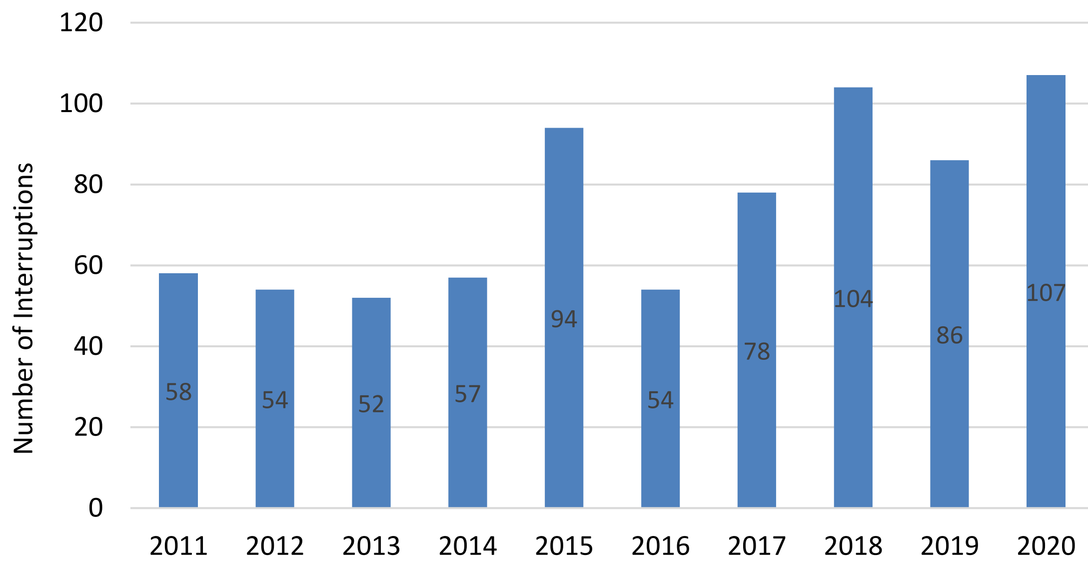


Figure 1: Number of Interruptions Attributed to Cross-arm Failures (Excluding FM Events)

SUBSTANDARD TRANSFORMERS

Certain types of line transformers have been identified as being obsolete or substandard. These transformer types include:

- Overhead transformers installed in underground-type enclosures;
- Transformers installed within steel poles; and
- Specific delta-wye connected transformers.

Approximately 1000 transformers have been identified as falling into one of the above three substandard installation categories. These installations are obsolete and pose unacceptable operational and/or safety risks. An example of these risks include specific transformer installations located inside buildings, which can be difficult to access. In the event of failure, some of these transformers may be impossible to replace in a like-for-like manner, and may require an extended outage and significant emergency work to relocate. A second example of these risks include pole transformers (see Figure 2 below), whose compact design results in insufficient operating clearances, and which are no longer available as a standard like-for-like replacement unit. Moreover, the replacement of these transformers requires outages to install and switch over to padmount transformers, which could entail minimal customer impact if done on a planned basis, but could result in prolonged outages in an unplanned failure. To address these risks, Hydro One replaces these transformers with standard transformers, reconfiguring as needed.

Figure 2: Pole Transformer

NEST PLATFORMS

Bird nests on distribution poles can potentially interfere with the safe and reliable operation of the distribution system. The presence of large nests increases the risk of pole fires. In addition, the birds themselves can make contact with distribution lines, causing outages to downstream customers and leading to the injury or death of the bird.

Bird nests are identified through regular inspection of distribution lines. When such nests are identified, they need to be relocated in order to safeguard the integrity of the distribution system and comply with all applicable regulations, including under the *Migratory Birds*

Convention Act, 1994. A photo is provided in Figure 2 below showing a bird nest required to be addressed through such work.

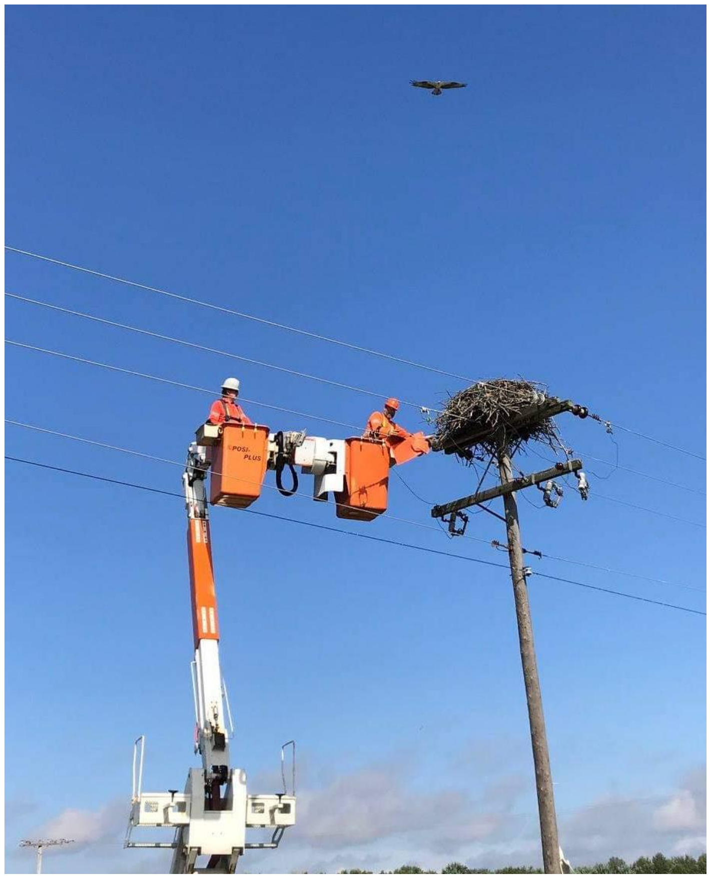


Figure 3: Bird Nest on a Pole

SENTINEL LIGHTS

Sentinel lighting is a service offered by Hydro One to install and maintain overhead dusk-to-dawn lighting for Hydro One customers (typically in rural settings without street lighting). While Hydro One no longer offers to install new sentinel lighting for customers, it is contractually obligated to maintain existing installations. Sentinel light failures are generally identified by Hydro One customers directly, and are reactively addressed as they occur.

B. INVESTMENT DESCRIPTION

This investment addresses the individual replacement or refurbishment of distribution line components when it is not economical to integrate the work into other lines-related capital investments (namely, D-SR-06, D-SR-07, D-SR-09, and D-SR-10). This investment includes the following types of work:

CROSS ARMS

Cross arms identified as being in poor condition are candidates for inclusion in the cross-arm replacement investment. Cross arms are selected for replacement based on the projected impact of failure, as measured based on the number of customers downstream of the relevant pole. When a cross arm is replaced, associated defects (e.g., damaged insulators) are also addressed. Table 1 shows the number of cross arms to be replaced as part of the cross-arm replacement investment (totaling 8,750 out of a population of about 20,000 units in poor condition).

Table 1 - Number of Cross Arms to be Replaced in the Plan Period

	2023	2024	2025	2026	2027	Total
Cross Arms Replaced	1,750	1,750	1,750	1,750	1,750	8,750

Only cross arms that are on poles in good condition are replaced as part of this investment. Cross arms on poles in poor condition are replaced as part of the pole replacement program (SR-07) to the extent those poles are included in that program. Cross arms that do not undergo planned replacement and fail during the planning period are replaced as part of the trouble program.

SUBSTANDARD TRANSFORMERS

Substandard transformers are replaced with transformer installations that are built to current Hydro One distribution standards.

Table 2 shows the number of transformers that are expected to be replaced as part of the substandard transformer investment. These transformers present operational and safety risks due to their space-constrained and obsolete designs. Replacing these substandard transformers proactively is also more efficient and cost-effective.

Table 2 - Number of Transformers to be Replaced in the Plan Period

	2023	2024	2025	2026	2027	Total
Transformers Replaced	230	310	270	70	20	900

NEST PLATFORMS

To safeguard the integrity of the distribution system and comply with relevant regulatory obligations, Hydro One Distribution addresses identified nest hazards through one of the following solutions:

- Installation of a nest platform on an existing pole, and relocation of the nest to this platform.
- Replacement of the existing pole with a taller pole, allowing for the installation of a nest platform. All equipment on the original pole would be transferred to the new, taller pole, and the nest would be relocated to the nest platform.
- Installation of a separate nest pole. The nest would be relocated to a platform on the new pole, leaving the original pole undisturbed.

Table 3 shows the forecasted number of nests that will be addressed during the planning period, based on historical volumes. The actual number will depend on bird activity and the presence of nests that require remedial action.

Table 3 - Number of Nests to be Addressed in the Plan Period

	2023	2024	2025	2026	2027	Total
Nests Addressed	13	13	13	13	13	65

SENTINEL LIGHTS

This investment replaces failed sentinel lights and removes sentinel lights and poles at the termination of rental contracts. This is a reactive program at the request of customers. All requests for work are received and forwarded through the Customer Care System. Specifically, the investment funds:

- Replacement of sentinel lights;
- Removal and disposal of sentinel lights; and
- Removal of sentinel light rental poles that are no longer needed.

Table 4 shows the forecasted number of sentinel lights that will be replaced or removed during the planning period. Since no new sentinel light agreements are being made, and customers can choose to terminate their rental agreements at any time, the number of active sentinel light installations is expected to decrease over time. The forecasted decrease in sentinel light replacements reflects this expected decrease in the number of active sentinel light installations.

Table 4 - Number of Sentinel Lights to be Replaced or Removed in the Plan Period

	2023	2024	2025	2026	2027	Total
Sentinel lights replaced/removed	2,600	2,400	2,100	1,900	1,700	10,700

Notably, in 2017, Hydro One adopted the use of LED fixtures for all replacement sentinel lights. These fixtures are expected to have a longer service life and to eliminate the need for sentinel light maintenance during the service life.

C. OUTCOMES

Hydro One aims to achieve the following outcomes as a result of the investment:

- Maintain reliability by replacing poor-condition cross arms that are prioritized based on customer impact;
- Reducing the risk of long-duration outages and increasing operational flexibility by replacing substandard and obsolete transformers;

- Reducing reliability risks due to bird nests while complying with applicable environmental legislation; and
- Replacing and removing sentinel lights in accordance with existing rental agreements.

OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 5 - Outcome Summary

Customer Focus	• Maintain reliability for customers by reducing the number of interruptions due to equipment failures. • Meet customer service obligations by replacing or removing sentinel lights.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively replacing deteriorated or substandard equipment.
Public Policy Responsiveness	• Relocate bird nests on distribution poles in accordance with applicable regulatory obligations, including under the *Migratory Birds Convention Act, 1994*.

D. EXPENDITURE PLAN

This program has been forecast for the planning period based on Hydro One's historical costs and either the planned units of work (in the case of cross arms and substandard transformers) or projected volume based on trends over time (in the case of bird nests and sentinel lights).

Table 6 below summarizes projected spending on the aggregate investment level. This program has been forecast for the planning period based on Hydro One's historical costs and either the planned units of work (in the case of cross arms and substandard transformers) or projected volume based on trends over time (in the case of bird nests and sentinel lights).

Table 6 – Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	14.0	16.5	15.4	9.7	8.1	63.7
Less Removals	1.6	1.9	1.8	1.2	1.0	7.6
Capital and Minor Fixed Assets	**12.4**	**14.5**	**13.5**	**8.6**	**7.1**	**56.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**12.4**	**14.5**	**13.5**	**8.6**	**7.1**	**56.2**

The factors influencing the cost of the investments include:

- Cross arms – targeting high impact cross arms, i.e., those that tend to support multiple conductors, is expected to lead to higher replacement costs.
- Substandard transformers – the unique nature of many substandard transformers results in highly variable replacement costs. An increased number of complex replacements would also lead to increased costs.
- Nest platforms – the cost of relocating nests identified on poles could vary depending on the location of the pole and the type of remedial action required.
- Sentinel lights – A strategic shift to replace all sentinel lights with LED fixtures is anticipated to lower life cycle costs.

E. ALTERNATIVES

Hydro One considered the below alternatives before selecting the recommended option. Given that Hydro One is proposing to replace sentinel lights and address nests on a demand basis, the alternatives discussed below focus on cross arms and substandard transformers.

ALTERNATIVE 1: REACTIVE REPLACEMENT

Reactive Replacements of Line Components as they fail.

This alternative was considered and rejected for both cross arms and substandard transformers due to unacceptable reliability risks. In the case of cross arms, failures could result in a high number of customers interrupted. In the case of some substandard transformers, failure could result in long outages for the customers supplied. Running these transformers to failure would also not resolve any safety risks associated with their obsolete designs.

ALTERNATIVE 2: PLANNED COMPONENT REPLACEMENT (RECOMMENDED)

Planned Replacement of Line Components at the Proposed Rate.

This alternative is recommended as it addresses high-priority operational risks related to cross arms and substandard transformers. In the case of cross arms, individual units are prioritized according to the number of downstream customers potentially impacted by a failure. In the case of substandard transformers, proactive replacement of these units mitigates operational and safety risks while also being more efficient and cost effective than reactive replacement.

ALTERNATIVE 3: ACCELERATED PLANNED COMPONENT REPLACEMENT

Planned Replacement of Line Components at an Accelerated Rate.

This alternative was considered and rejected for cross arms, as the efficiency of the additional investment would be low due to the cost associated with this alternative relative to the number of customers impacted.

F. EXECUTION RISK AND MITIGATION

The primary execution risk relates to substandard transformer replacements that often involve the replacement of transformers in higher density areas, which may lead to design complexities. This risk is mitigated by identifying particularly complex units as part of the detailed design process, and planning accordingly by taking into account site specific challenges and the associated impact on scheduling.

D-SR-09	**SUBMARINE CABLE REPLACEMENT PROGRAM**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
Net Cost	12.2	12.5	12.7	13.0	13.2	63.5

Summary:

This investment involves the replacement and refurbishment of submarine cables when they are found to be damaged or exposed. The primary trigger of the investment is the condition of individual submarine cables. The investment is expected to reduce the public safety risk due to damaged or exposed cables as well as maintain reliability by preventing unplanned interruptions to customers from defective submarine cable.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One's distribution system contains approximately 12,000 submarine cable installations, primarily used to supply island dwellings or to substitute for overhead water crossings when these are not technically or economically feasible. Due to the nature of their installation, submarine cables are especially prone to damage and corrosion where they enter a body of water. This damage is of special concern as it occurs at a location which can be accessible to the public and can pose serious health and safety risks.

As discussed in DSP Section 3.2, distribution system patrols have found approximately 600 cables which have become damaged, and an additional 400 cables that are exposed at the shoreline. Damaged cables usually exhibit abrasion or corrosion of the protective cable armour, which can lead to neutral failure or water ingress. Exposed cables are not necessarily damaged, but are subject to increased environmental risks, and are more likely to become damaged over time. Cables that are damaged can pose significant public safety hazards, as well as increased reliability risks.

Figure 1: Example of (left) an Exposed Cable Showing Initial Signs of Corrosion, and (Right) a Corroded Cable with Significant Damage

B. INVESTMENT DESCRIPTION

Damaged or exposed cables are identified during the course of regular inspections, which occur on a six year (rural) or 3 year (urban) frequency. If an inspection identifies a submarine cable that poses an immediate safety hazard, it is addressed by the Distribution Lines Trouble Call and Storm Damage Response Program (D-SR-05). If a damaged or exposed cable is identified but does not pose an immediate safety hazard, it is addressed via this planned investment.

A damaged cable may be fully or partially replaced (i.e., by splicing a new section), depending on the specific circumstances. For example, localized cable damage on a newer, otherwise good cable may be addressed by a partial replacement of the cable. However, given the relatively high costs of repairing cables, as well as the fact that cables can become damaged over their entire length, the majority of damaged cables are fully replaced.

An exposed cable that is not damaged can be addressed by installing mechanical protection. Depending on the nature of shoreline where the cable enters the water, a number of options are available to mechanically protect the cable, including installation of a duct or covering the cable with concrete. Since cables are typically subject to the highest environmental degradation at the shoreline, and since public contact with a cable can typically only occur where a cable is accessible to the public, cables are only mechanically protected where they are on land and where they enter the water.

This investment is expected to replace or refurbish all submarine cables with currently known defects and additional cables that become damaged or exposed over the planning period.

C. OUTCOMES

Addressing damaged cables on a planned basis is a cost efficient way to reduce the public safety risk associated with submarine cable installations and prevent cable failures leading to unplanned customer interruptions. This investment is expected to keep pace with the renewal requirements of the cable population over time and minimize this risk.

Addressing exposed cables protects them from environmental damage, which can lead to their damage and premature retirement. This investment is expected to keep pace with the number of exposed cables being discovered on an ongoing basis.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Mitigate public safety hazards from defective submarine cables. • Maintain reliability by preventing interruptions to customers from defective submarine cable.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively replacing deteriorated equipment.

D. EXPENDITURE PLAN

Table 2 below summarizes historical spending on the aggregate investment level.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	13.9	14.1	14.4	14.7	15.0	72.2
Less Removals	1.7	1.7	1.7	1.8	1.8	8.7
Capital and Minor Fixed Assets	**12.2**	**12.5**	**12.7**	**13.0**	**13.2**	**63.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**12.2**	**12.5**	**12.7**	**13.0**	**13.2**	**63.5**

The level of investment is directly driven by submarine cable inspection findings and aims to address all defective cables in a timely manner. Updates to Hydro One Distribution Standards requiring improved cable designs and mechanical shoreline protections have increased costs over historical levels.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: REACTIVE SUBMARINE CABLE REPLACEMENT

This alternative would involve waiting for submarine cables to pose an immediate safety risk while in service, and replacing them on a reactive basis. This alternative was rejected as it results in an unacceptable safety risk to the general public and employees. Additionally, emergency repairs are more expensive and can result in an extended interruption while work is being completed.

ALTERNATIVE 2: PLANNED REPLACEMENT/REFURBISHMENT OF DAMAGED OR EXPOSED SUBMARINE CABLES (RECOMMENDED)

The recommended alternative replaces or refurbishes damaged and exposed cables as part of a planned program as these cable deficiencies are discovered. Together with the D-SR-05 Trouble investment, this approach mitigates the safety risks associated with these cables while maintaining a relatively stable investment level.

ALTERNATIVE 3: REPLACEMENT OF ALL NON-STANDARD SUBMARINE CABLE

This alternative would involve the replacement or refurbishment of all submarine cables that are not to current Hydro One standards, regardless of condition. This alternative was rejected as it is not cost effective, and non-standard cables do not necessarily pose a safety hazard.

F. EXECUTION RISK AND MITIGATION

Submarine cable replacement requires specialized equipment and unimpeded cable access. As a result, there are a number of execution challenges associated with this activity, including the fact that cables cannot typically be replaced during the winter season. In order to mitigate this risk, the investment is scheduled to avoid these frozen conditions.

Additionally, distribution submarine cable itself is a fairly specialized material which can be difficult to source. In past years, demand from Hydro One has exceeded the available supply. Hydro One has mitigated this risk by working with our cable supplier to ensure available supply meets scheduled needs.

D-SR-10	DISTRIBUTION LINES SUSTAINMENT INITIATIVES
Primary Trigger:	Asset Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	31.5	30.3	35.3	43.2	42.7	183.0

Summary:

The investment is expected to address (1) overhead feeders that contain end-of-life assets due to their condition and, as a result, require rebuilding and often relocation from off-road locations to road side, and (2) underground feeders where cable condition warrants intervention by cable injection. The primary trigger of the investment is asset condition. These investments propose to address sections of feeders that have been identified to be in poor condition in a coordinated manner to maintain reliability of the feeder, and in the cases of relocation of off-road sections to road side, improve reliability.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One's distribution system consists of more than 123,000 circuit kilometers of primary feeder lines across the province. Feeders are made up of multiple components, including conductors, poles, insulators, cross arms, and guy wires (as discussed in DSP Section 3.2). Some poles also support overhead transformers, switches, reclosers, and capacitor banks. While the vast majority of Hydro One's distribution feeders are overhead (about 92%), a small portion (about 8%) are underground and submarine feeders that primarily consist of cables, pad-mount transformers, and underground switching equipment (i.e., kiosks).

The Distribution Lines Sustainment Initiative addresses (1) overhead feeder sections that contain a large proportion of end-of-life assets based on their condition and, as a result, require rebuilding and often relocation from off-road locations to road side, and (2) underground feeders where cable condition warrants cable injection. In the case of (1), the rebuilds involve rebuilding and often relocating the entire feeder section, including poles, conductor, and hardware. This is in contrast to the investments in the ISD D-SR-07, which focus on replacing individual poles and their associated hardware in place.

OVERHEAD FEEDERS

As outlined in DSP Section 3.2, Hydro One assesses the condition of its distribution assets, including the components that comprise its distribution feeders. These assessments have identified that a number of assets require replacement as a result of reaching end-of-life based on their condition. The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, and other factors that reduce their structural integrity. Once a pole's condition has deteriorated to poor condition, the pole is deemed to be at end of life and is at risk of failure.

Compounding this failure risk associated with poor-condition assets, where overhead feeders are located away from road side, Hydro One distribution crews face significant challenges with respect to restoration activities. In general, when off-road equipment fails, replacing it takes substantially longer than replacing a similar asset that is road side. For example, off-road access for pole setting typically requires specialized bucket-truck and remote boom derricks with off-road treads rather than traditional road-worthy tires. Transporting such equipment to the off-road lines presents its own additional challenges, which increase the time and effort required to restore affected customers.

By addressing line segments that have high concentrations of end-of-life assets, Hydro One's Distribution Lines Sustainment Initiatives are expected to minimize the risk of failure arising from these deteriorated assets. Further, by relocating off-road and end of life poles and equipment to a suitable road, the Distribution Lines Sustainment Initiatives are expected to reduce the duration of restoration activities in the event of outages on these off-road sections. Specifically, off road feeder sections can experience 2.3 times the average outage length compared to feeder sections that are roadside.

Based on the inspection and testing of overhead feeders, Hydro One has identified approximately 480 kilometers of distribution line sections that will require rebuilding due to end-of-life condition and will, when practicable, be relocated to road side during the plan period. As a result of overhead Distribution Line Sustainment initiatives, reliability of the feeders will be maintained. In the cases where an off-road feeder section is being relocated on to road side, an annual average reliability improvement of approximately 20% for customers supplied from the subject feeders is expected.

UNDERGROUND FEEDERS

A significant number of station egresses that serve Hydro One Distribution's 1.4 million customers rely on underground cables to both enter and exit the stations. Underground cables also serve large residential and industrial subdivisions in more populated areas. Failures of underground cables may result in significant outages to customers due to a more complex and time-consuming restoration process. Crews would have to locate the issue, conduct excavation (by digging or hydrovac) to examine the asset, evaluate whether the defect is repairable, and conduct repairs or splice in a new cable as required.

To prevent such outages from occurring, a technique known as cable injection can be used to proactively rejuvenate end-of-life cables. Specifically, this technique would be used to refurbish cables with insulation degradation (i.e., "water trees," which are small holes in the insulation that can cause short circuits and destructive cable failures once they protrude entirely through the cable insulation). The technique involves de-energizing the cable and injecting a liquid insulating material into both ends of the cable. This liquid fills in the gaps between each strand and eventually diffuses into the insulation to fill water trees.

Hydro One introduced a cable injection pilot program in 2018. The pilot program showed, among other things, a 65% savings in cost from cable injection (where feasible) relative to traditional capital replacement. In contrast to the traditional method of digging up direct-buried cable to perform replacements, cable injection provides minimal disruption to the physical surface of the road, as the fluid is injected from one cable termination point to the next. Upon completion of the cable injection pilot, the relevant feeder experienced an approximately 80% reduction in the two-year average SAIDI before and after completion of the pilot project.

Based on vendor information, cable injection can be expected to increase the useful life of cables by up to 40 years, providing an economical alternative to replacing direct-buried cables (which make up the majority of underground feeders on Hydro One's distribution system). Building on the pilot program, Hydro One proposes to continue cable injection across its service territory over the plan period.

B. INVESTMENT DESCRIPTION

There are a number of investments identified under this ISD, which vary in size and scope. The investments are described below. Those with net capital investment exceeding $1M are provided in the appendix.

OVERHEAD FEEDERS

Distribution Line Sustainment Initiatives address overhead feeder sections in an integrated manner by addressing line equipment that is in poor condition and that would negatively impact customer reliability in the event of failure. Feeder sections are identified and prioritized for inclusion in this investment over the plan period based on the condition of the feeder asset components and associated consequences in the event of failure.

Rebuilding a feeder section is preferred when (1) the condition of asset components is deteriorated and the cost of maintaining or replacing individual components on a case-by-case basis on that section becomes less economical than rebuilding the line section, or (2) the end-of-life feeder sections are located off-road, creating a physical barrier to timely restoration in the event of outages. The proposed investments are expected to maintain reliability on these feeder sections and in the case of off-road sections, reduce outage impact to customers.

In general, the scope of work involved in a feeder rebuild or relocation is the replacement of all poles, and all equipment connected to those poles, in a particular line section. The preferred approach is to address feeder sections that have a large number of poor-condition assets in close proximity through one line rebuild/relocation investment, as this eliminates the need to mobilize crews multiple times to address different feeder components on the same section. By addressing poor-condition assets and performing relocations in a planned and integrated manner, Hydro One also has the opportunity to bring assets up to current standards and to meet anticipated operational needs, including, for example: (1) increased pole height and framing to accommodate additional anticipated circuits; and/or (2) installation of larger and less resistive conductor to increase feeder voltage performance and provide additional load-carrying capacity.

The planned Distribution Lines Sustainment Initiatives include rebuilding approximately 480 kilometers of distribution line sections due to their condition, often relocating them to road side.

CABLE INJECTION

As part of cable injection, all splices, breaks, and corrosion in the cable are identified using time-domain reflectometer (TDR) testing. Once these are identified, a proprietary fluid is injected through the stranded phase conductors from one splice to the next. During the injection process, the fluid displaces contaminants and travels through the gaps in the conductor strands to the gaps in the cable insulation. Over time, the water trees are filled as the fluid diffuses into the insulation, improving the dielectric integrity of the cable, and thus the life of the cable.

The fluid can be injected at two different pressures: low pressure and high pressure. Low-pressure injection has a manufacturer's warranty of 25 years, whereas high-pressure injection has a manufacturer's warranty of 40 years. The low-pressure method results in a slow injection rate; however, this method allows the conductor to remain energized as the fluid is being injected, which is particularly beneficial for maintaining continuity of supply on a radial feed. High-pressure injection consists of pressure that is 16 times greater than that of the low-pressure method; it therefore has a much faster injection rate. This method is ideal when back-feeding capabilities are present (i.e. the cable being worked on is not required to be energized to supply customers). The flexibility of cable injection methods allows Hydro One to limit the impact of disruption to customers, not only in terms of possible scheduled outage length, but also in terms of destructive digging that would be required with traditional cable replacement.

An example of a cable injection project that Hydro One is currently pursuing is the Fairchild Transformer Station (TS) M11 and M12 cable injection alternative, which is expected to go in-service in late 2022. Fairchild TS is located in a highly dense urban area of Toronto at the intersection of Yonge Street and Finch Avenue. Both the M11 and M12 feeders, which are each 2 kilometer-long direct-buried cables, have failed and need to be addressed. The M11 and M12 feeders carried approximately 16 MW of load at 27.6 kV prior to failure. Proceeding with traditional cable replacement (i.e. digging up the buried cable on busy roads and installing new cable) has a total projected cost for both feeders of $8M, compared to only $3M for cable injection.

In addition to being significantly more cost effective, cable injection can be performed much more quickly than traditional cable replacement, with minimal disruption to the road under which distribution cables are direct buried. For example, the Fairchild TS project to extend the life of the existing Fairchild TS cables will be completed 2 years earlier than the forecasted completion date for direct replacement of the cables. This is because, unlike cable injection, traditional cable replacement requires detailed design, locates, road authority approval, and excavating the entire cable.

Over the plan period, 200 kilometers of direct-buried cable is planned to be addressed using cable injection. Hydro One evaluates cables for defects at the start and end points of underground cables (such as at underground transformers or at dip/riser poles).

The planned candidates for cable injection include the direct buried subdivision cables in the Orleans area. The Orleans area is one of Hydro One's most dense subdivision areas and has some of the oldest cables in the province, which have now reached end of life and have been experiencing multiple failures in recent years. The cable injection pilot project was launched in 2018 on one of the feeders in Orleans to mitigate failure risk. Due to the success of the pilot project, Hydro One plans on expanding cable injection investments to include the remaining end of life direct buried cables in the Orleans subdivisions that are feasible to undergo cable injection.

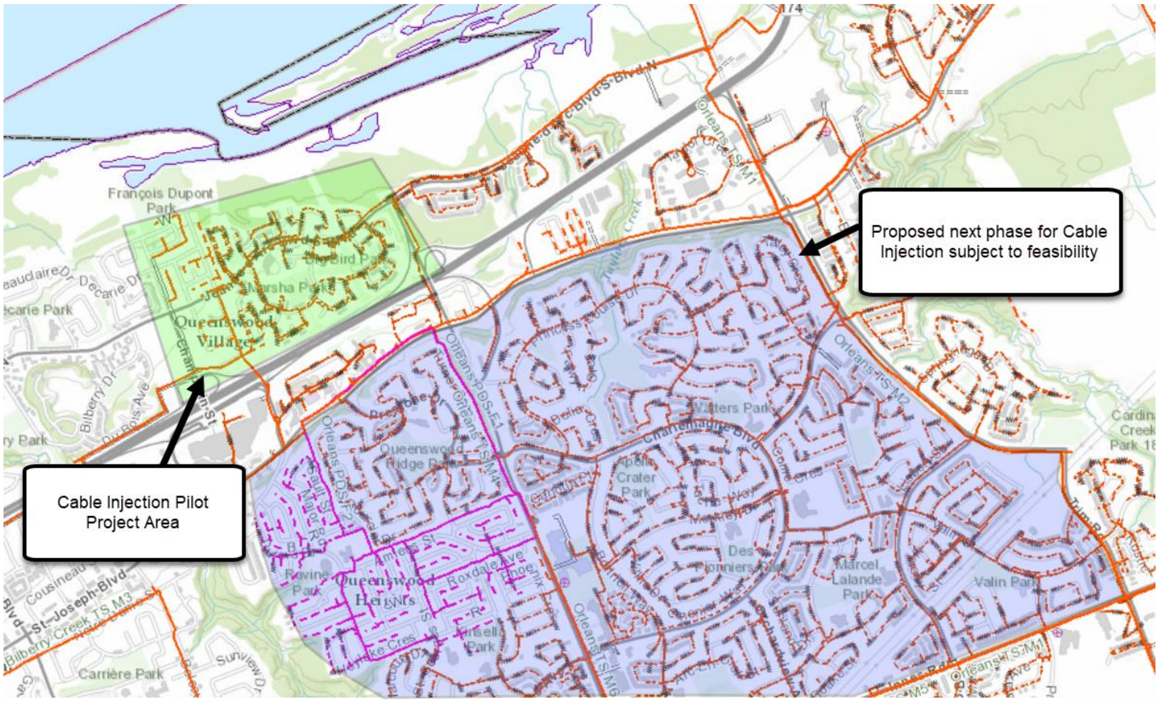


Figure 1: Outlining the Historical and Proposed Cable Injection Areas in the Orleans Subdivisions

C. OUTCOMES

Distribution Line Sustainment initiatives will:

- Rebuild approximately 480 kilometers of distribution line sections and relocate off-road assets to road side;
- Maintain reliability on feeders with end-of-life condition assets that warrant rebuilding sections in place;
- Improve reliability where off-road sections are relocated on to roadside by an average of approximately 20% for customers supplied from the subject feeders;
- Extend the life of approximately 200 kilometers of direct-buried underground cable by up to 40 years.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Maintain reliability for customers by reducing the likelihood of outages on distribution lines. • Improve restoration time for customers by relocating off-road line sections to more accessible locations.
Operational Effectiveness	• Maintain reliability on feeder sections and in the case of off-road section relocations, improve reliability by reducing the outage impact to customers. • Maintain safe and reliable operation of the distribution system by proactively addressing lines equipment in an integrated manner.

D. EXPENDITURE PLAN

Table 2 below summarizes projected 2023-2027 spending at the aggregate investment level.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	35.7	34.3	39.2	49.1	48.3	206.6
Less Removals	4.2	4.0	3.9	5.9	5.6	23.6
Capital and Minor Fixed Assets	**31.5**	**30.3**	**35.3**	**43.2**	**42.7**	**183.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**31.5**	**30.3**	**35.3**	**43.2**	**42.7**	**183.0**

The forecast for Distribution Lines Sustainment Investments are based on historical project costs and the volume of work identified over the plan period.

The forecast for cable injection investments (SR-10.34) was developed to address approximately 200 km of direct buried cable and was based on the costs from the cable injection pilot project.

The factors influencing the cost of the investment include:

- The number and length of distribution circuits on the section of line that is being relocated;
- The accessibility and length of the feeder being removed and length of the new feeder being constructed;
- The extent of forestry work required at the new feeder location;
- The set-backs required by the road authority or property owner at the new location;
- Unforeseen property/easement issues; and
- The number of cable splices present for underground cables.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: REACTIVE REPLACEMENT

This alternative would involve reactively replacing distribution line equipment after they fail. This alternative is rejected, as emergency replacements typically lead to prolonged outages (especially for off-road feeder sections) and may be more costly as resources may be required outside of normal working hours. Moreover, reactive management of the distribution line equipment will lead to increased failures, resulting in degradation of reliability for Hydro One's customers.

ALTERNATIVE 2: PLANNED COMPONENTS REPLACEMENTS

This alternative would involve the planned replacement of distribution line equipment 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 efficient when multiple components are in deteriorated condition or the components are of substandard design, as individual replacement work lacks the cost efficiencies associated with the integrated replacement of multiple assets in close proximity to each other. Moreover, custom-engineered designs would be necessary to address substandard equipment that is no longer supported at Hydro One. Furthermore, this alternative would not address off-road accessibility concerns, and as such would result in longer restoration durations for off-road assets. This alternative also does not leverage the available cable injection technology to extend the life of underground cables. For these reasons, this alternative is rejected.

ALTERNATIVE 3: PLANNED LINES SUSTAINMENT INITIATIVES (RECOMMENDED)

This alternative involves the planned rebuilding of feeder sections and relocation of off-road sections to road side, where the components of the distribution line section have been identified as being in poor condition. This alternative would also involve planned cable injection to extend the life of deteriorating cable sections and mitigate cable failures. This alternative is recommended as it addresses the needs identified on distribution lines in order to maintain, and in the case of off-road locations improve, the reliability of the distribution system in the most cost-effective manner.

F. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the investment may include seasonal access limitations, and equipment outage availability. These risks are mitigated through extensive planning, scheduling, and outage coordination across lines of business and stakeholders.

1 **APPENDIX A – DESCRIPTION OF INVESTMENTS**

Project Name	Project ID	Project Description	Net Capital Investment ($M)				
			2023	2024	2025	2026	2027
Angus 44kV Backlot Relocate, Barrie Line Relocate	SR-10.1	3.3 km Relocation	2.1	0.0	0.0	0.0	0.0
Lindsay M7 Line Relocation Stage 1+2	SR-10.2	12 km Relocation	3.0	0.0	0.0	0.0	0.0
Lindsay M7 Line Relocation Stage 3	SR-10.3	2 km Relocation	1.8	0.0	0.0	0.0	0.0
Owen Sound Line Rebuild - Part 3	SR-10.4	5.1 km Rebuild	0.0	2.2	0.0	0.0	0.0
Owen Sound Line Rebuild - Part 4	SR-10.5	4.8 km Rebuild	0.0	1.2	0.0	0.0	0.0
Gardiner TS M14 Relocation	SR-10.6	4.2 km Relocation	0.0	1.8	0.2	0.0	0.0
Kent TS M16 Relocation	SR-10.7	18 km Relocation	0.0	0.1	1.1	0.0	0.0
Kingsville M1 and M5 Relocation In Town	SR-10.8	1.5 km Relocation	0.1	0.8	0.3	0.0	0.0
Napanee TS M2 Relocation	SR-10.9	9 km Relocation	0.0	0.3	2.7	0.0	0.0
Tillsonburg TS M4 Relocation	SR-10.10	6.3 km Relocation	0.0	2.1	0.2	0.0	0.0
Town of Schreiber Relocation Phase 3	SR-10.11	1 km Relocation	1.0	1.0	0.1	0.0	0.0
Weston Lake DS F1 – Kukatush Line Section Relocation	SR-10.12	6.2 km Relocation	0.0	1.8	0.0	0.0	0.0
Manitoulin TS M25 - Relocation	SR-10.13	5 km Relocation	0.0	0.1	1.6	0.0	0.0
Muskoka TS M1 Relocation - Part 6	SR-10.14	16.3 km Relocation	0.0	0.1	5.4	0.0	0.0
Owen Sound TS M24 Rebuild - Stage 2	SR-10.15	9 km Relocation	1.1	0.0	0.0	0.0	0.0
Owen Sound TS M24 Rebuild - Stage 3	SR-10.16	9 km Relocation	0.0	0.6	2.2	0.0	0.0
Clarke TS M2 Towerline Relocation	SR-10.17	3.8 km Relocation	6.3	0.6	0.0	0.0	0.0
Muskoka TS M1 Relocation - Part 2 of 5	SR-10.18	6 km Relocation	0.0	0.0	0.1	4.7	0.0
Waubaushene TS M1 Rebuild	SR-10.19	2.9 km Rebuild	0.0	0.0	0.1	1.8	0.0
Waubaushene TS M3/M7 Line Relocation	SR-10.20	1.84 km Relocation	0.0	0.0	0.0	0.1	1.1
Crosby TS M6 Line Relocation	SR-10.21	9 km Relocation	0.0	0.0	0.7	6.5	0.0
Douglas Point TS 44kV U/G Cables	SR-10.22	1.4 km Cable Replacement	0.0	0.0	0.1	1.6	0.8
Dymond TS M3 Rebuild- Stage 2	SR-10.23	22 km Rebuild	0.0	0.0	0.0	0.0	4.4
Errington Street Rebuild	SR-10.24	1.6 km Rebuild	0.0	0.0	0.0	0.1	1.7
Herridge Lake - Rebuild	SR-10.25	6 km Rebuild	0.0	0.0	0.0	0.1	1.5
Kent TS M16 Relocation within Town	SR-10.26	2.3 km Relocation	0.0	0.4	1.7	2.1	0.5
Lambton TS M2 and M4 off road relocation	SR-10.27	2.7 km Relocation	0.0	0.0	0.5	2.1	2.6
Meaford TS M1 Relocate– Lower Valley Road	SR-10.28	1.7 km Relocation	0.0	0.0	0.0	0.2	1.4
Napanee TS M4 Relocation Phase 1 to Marysville	SR-10.29	2.5 km Relocation	0.0	0.0	0.0	0.2	1.4

Project Name	Project ID	Project Description	Net Capital Investment ($M)				
			2023	**2024**	**2025**	**2026**	**2027**
Owen Sound TS M25 Rebuild Hepworth x Sauble	SR-10.30	11 km Rebuild	0.0	0.0	0.3	2.8	1.4
Stayner TS M2 Supply Rebuild	SR-10.31	8 km Rebuild	0.0	0.0	0.0	0.1	3.5
Waubaushene TS M1 Rebuild Part 2	SR-10.32	5.7 km Rebuild	0.0	0.0	0.1	2.0	1.0
Commerce Way M2 Offroad Relocation	SR-10.33	3 km Relocation	0.0	0.0	0.0	0.0	1.2
Underground Cable Injection	SR-10.34	Address Direct Buried Cable using Cable Injection. 200km proposed over the plan period.	3.9	4.0	4.1	4.0	4.0
Other Projects (<$1M)			12.2	13.2	13.8	14.8	16.2
Total			**31.5**	**30.3**	**35.3**	**43.2**	**42.7**

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D-SR-11	**LIFE CYCLE OPTIMIZATION & OPERATIONAL EFFICIENCY PROJECTS**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
Net Cost	2.8	6.5	7.1	0.8	0.4	17.7

Summary:

This investment involves the optimization of the distribution system by eliminating poor condition assets through system modifications or voltage conversion. The primary trigger of this investment is asset condition. This investment is expected to reduce costs and increase operational efficiencies.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

While Hydro One typically replaces assets in poor condition on a like-for-like basis, in some situations system needs can be met by removing poor condition assets and reconfiguring the system through other, more cost effective alternatives. These alternatives vary in scope, but are most often characterized by voltage conversion or system modifications such as load transfers. The elimination of assets, typically distribution stations, in lieu of replacement form the basis for investments within this ISD.

Stations in poor condition have an elevated risk of unplanned failure, which can lead to lengthy service interruptions. In addition to like-for-like replacement, there are sometimes alternative approaches that can meet system needs at a lower cost. As an illustrative example, rather than refurbishing a poor condition station, a station could be decommissioned and its customer loads transferred to neighbouring feeders or converted to a higher voltage.

The stations that are candidates for decommissioning through this ISD were designed and constructed decades ago, and presently supply a distribution system that has evolved drastically from what the original designers may have envisioned. Life cycle optimization investments are an opportunity to revisit and update the electrical distribution network to best reflect current system needs.

B. INVESTMENT DESCRIPTION

Hydro One considers broad system needs when assessing options to address stations in poor condition. The preferred alternative is that which meets system needs in the most cost-effective manner. In cases where like-for-like replacements are not the most cost-effective investment to meet system needs, Hydro One uses two approaches to improve operational efficiency and optimize asset life cycle costs: (i) system modifications, and (ii) voltage conversion. The investments made under both approaches are summarized in the sub-sections below.

I. STATION DECOMMISSIONING THROUGH SYSTEM MODIFICATIONS

Through these investments, Hydro One removes poor condition and under-utilized stations from service by transferring load to nearby assets. Load transfers are varied in nature, and the feasibility of these projects depends on the capability of the surrounding system. Where possible, load transfers can be achieved by:

i. Transferring load to feeders supplied by neighbouring stations.
ii. Transferring load to new padmount transformers that are installed along the line.

II. STATION DECOMMISSIONING THROUGH VOLTAGE CONVERSION

Through voltage conversion investments, Hydro One can remove a station from service by converting the operating 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 at end-of-life, and improves the voltage quality and capacity of the downstream feeders.

In the previous Distribution rates filing (2018-2022), many of the investments planned under this ISD were voltage conversion projects similar in scope to example above, resulting in the elimination of a poor-condition distribution station. Where it was determined that stations assets could be removed, voltage conversion was typically selected as a feasible option, if the costs of conversion were less than the costs of a station refurbishment.

Hydro One initiated the use of padmounted distribution stations which are often a cost-effective alternative to traditional station refurbishments. As a result, many system needs that would previously have been addressed through a voltage conversion investment are now more cost effectively addressed through a new padmounted distribution station. In these cases, the investment is considered a “Station Refurbishment” under ISD D-SR-04. A further consequence of this change is a significant decrease in expenditures within D-SR-11, and a corresponding increase in station refurbishment projects under D-SR-04. However, there are instances where voltage conversion is still the preferred option.

EXAMPLE INVESTMENT "MATHESON DS"

Matheson DS is a 3MVA station located in Matheson, Ontario, and is supplied at 27.6kV from Ramore TS. To serve customers in the area, Matheson DS steps the voltage down from 27.6kV to 12.5kV, and distributes electricity at the reduced voltage. Although Matheson DS has served as a distribution supply to the local area for many years, it is now in poor condition. The station's condition warrants a review of local supply capabilities, which are much different now than they were at the time of station construction many decades ago. A solution is required to avoid a station failure, and the associated reliability impact. Figure 1 below shows the existing distribution system in the Ramore / Matheson area.

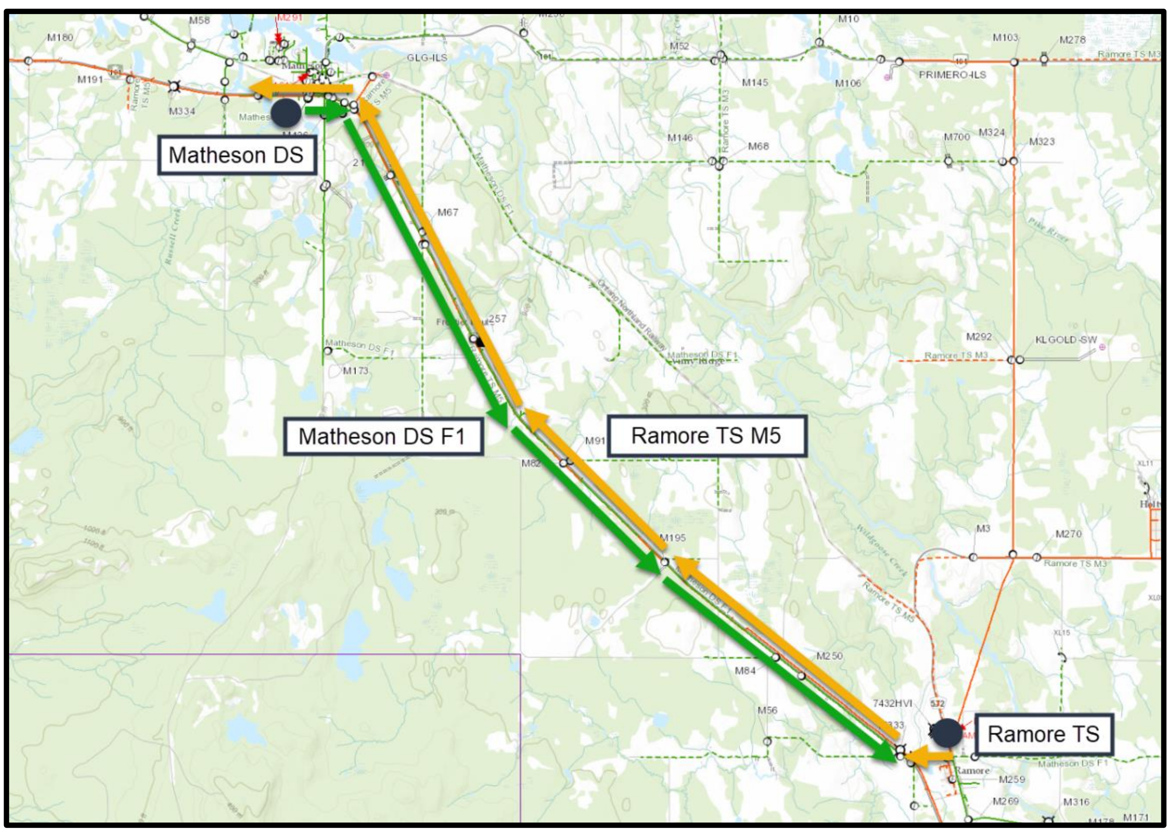

Figure 1: Existing configuration of Ramore TS and Matheson DS

The proposed optimization involves decommissioning Matheson DS and migrating its customers to Ramore TS M5 through voltage conversion. This proposal will address the condition of Matheson DS, will simplify the electrical distribution in the area by using a single distribution voltage, and as a result, will reduce the amount of overall assets required to supply the load. The viability of voltage conversion as a solution is strengthened for this project, since the required 27.6kV supply already exists on the same poles as the 12.47kV circuits.

Figure 2 below shows the proposed distribution configuration, with Matheson DS removed, and only a single distribution voltage along Highway 11.

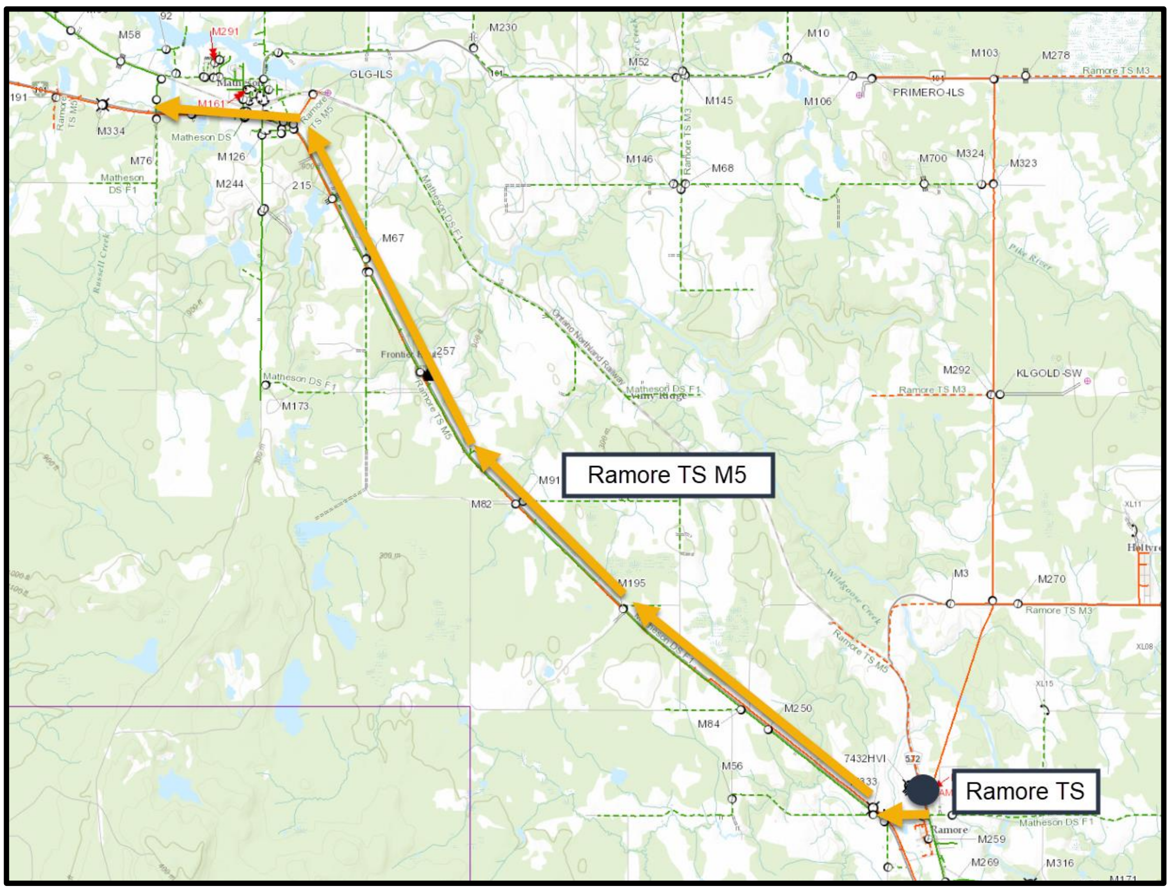

Figure 2: Proposed removal of Matheson DS

Although a padmount distribution station was also a viable solution that was considered for this project, voltage conversion is preferable. While the costs are comparable for both voltage conversion and a padmount distribution station in this case, the voltage conversion approach offers incremental benefits that include additional capacity to enable future load growth and increased efficiency of supply by reducing system losses.

C. OUTCOMES

Life Cycle Optimization investments focus on the efficient use of assets. By taking into consideration not just asset condition, but also the degree to which assets are utilized, Hydro One eliminates assets where practically feasible, leading to a reduction in the assets required to own, operate, and maintain the distribution system.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Avoid customer interruptions by reducing the number of outages at distribution stations.
Operational Effectiveness	• Maintain safe and reliable operation of distribution stations by addressing poor condition station equipment in an integrated and cost-effective manner. • Increase operational efficiencies by eliminating underutilized assets where practically feasible, and unifying operating voltage. • Minimize costs by choosing the lowest-cost alternative that addresses the area supply needs.

D. EXPENDITURE PLAN

Table 2 below summarizes projected annual expenditures on the aggregate level. Since this ISD is comprised of unique investments, with different planned execution timelines, the associated expenditures vary year-over-year. A detailed breakdown of all expenditures that constitute this ISD can be found in Appendix A.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	3.6	8.2	9.4	1.4	1.0	23.6
Less Removals	0.8	1.7	2.3	0.6	0.6	5.9
Capital and Minor Fixed Assets	**2.8**	**6.5**	**7.1**	**0.8**	**0.4**	**17.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.8**	**6.5**	**7.1**	**0.8**	**0.4**	**17.7**

The factors influencing the cost of the investment include:

- Construction costs for voltage conversion work can vary depending on conditions such as ground conditions and the number of circuits on the pole line.
- Older lines tend to require more replacement and upgrading to current standards.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: DO NOTHING

Not proceeding with this investment would fail to address system assets in poor condition, which would lead to an increased risk of failure and a deterioration in reliability.

ALTERNATIVE 2: ADDRESS END OF LIFE ASSETS THROUGH PLANNED LIKE-FOR-LIKE REPLACEMENT

This approach would address all end-of-life assets only through like-for-like replacements through other system renewal projects or programs. This alternative is not recommended since it would result in foregoing the opportunity to reduce costs by modifying the configuration and eliminating assets where feasible.

ALTERNATIVE 3: ADDRESS END OF LIFE ASSETS THROUGH OPTIMIZED SYSTEM PLANNING (RECOMMENDED)

Under the recommended approach, Hydro One will address specific end-of-life asset needs by means other than like-for-like replacement where there are opportunities to reduce costs and achieve increased operational efficiencies. When stations are at end-of-life based on condition assessments, there may be opportunities to implement system changes other than like-for-like replacement. The preferred approach in these cases is to eliminate stations through voltage conversion or load transfers.

F. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the investment may include seasonal access limitations, and equipment outage availability. These risks are mitigated through extensive planning, scheduling, and outage coordination across lines of business and stakeholders.

1 **APPENDIX A – DESCRIPTION OF INVESTMENTS**

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2023	**2024**	**2025**	**2026**	**2027**
Embrun DS	SR-11.1	Decommission Embrun DS. Transfer station loads to Marionville DS F1, by voltage converting from 8.32kV to 27.6kV	0.2	1.1	0.0	0.0	0.0
Matheson DS	SR-11.2	Decommission Matheson DS. Transfer station loads to Ramore TS M5 by voltage converting from 12.5kV to 27.6kV.	0.0	0.1	1.4	0.0	0.0
St.Thomas DS	SR-11.3	Decommission St Thomas DS. Transfer station loads to Edgeware TS M2 by voltage converting from 8.32kV to 27.6kV.	0.8	2.4	0.0	0.0	0.0
Elliot Lake - Station Upgrades	SR-11.4	Decommission Elliot Lake DS. Transfer station capacity to Porridge Lake DS, and rearrange distribution supply.	0.0	0.6	2.3	0.0	0.0
Other Projects (<$1M)			1.8	2.3	3.4	0.8	0.4
Total			**2.8**	**6.5**	**7.1**	**0.8**	**0.4**

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D-SR-12	ADVANCED METER INFRASTRUCTURE 2.0 (AMI 2.0)
Primary Trigger:	Obsolescence/Compliance
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	30.9	62.0	153.7	154.4	157.3	558.3

Summary:

This investment involves the the replacement of Hydro One's legacy AMI 1.0 system with a new AMI 2.0 system because it is reaching the end of its 15 year service life with meters showing conditions of disrepair, an increasing number of meter failures and increasing costs of performing individual reactive meter replacements. Meter failure projections, based on independently conducted Accelerated Life Testing of meters, estimate 579,000 meters (45% of the total meter population) are expected to fail by the end of 2027. High meter failure rates, without intervention, pose significant and critical risks to Hydro One's operations, affecting various aspects of its business. The primary trigger of the investment is regulatory compliance. The investment is expected to maintain billing accuracy, improve network communication, reduce manual meter reading, provide faster response times to some types of disconnection/reconnection requests, and provide customers with a modern AMI platform to meet foreseeable customer needs over the lifetime of the assets.

A. INTRODUCTION

Advanced Metering Infrastructure (AMI) for retail revenue metering refers to all of the components (smart meters, repeaters, regional collectors, Head End System, and related software and firmware) that work together as a system to reliably obtain over-the-air meter readings for accurate and reliable Time-of-Use and Two-Tier customer billing in accordance with provisions of the OEB's *Standard Supply Service Code*. AMI can also provide a platform for improving customer service and reducing costs through enabling technology such as outage detection, the provision of customer usage information, tamper detection, and remote disconnect/reconnect capabilities.

Hydro One began the deployment of its first-generation Advanced Metering Infrastructure (AMI 1.0) system in 2007 in accordance with the direction of the Province of Ontario. The Province's adoption of AMI was among the first large-scale AMI deployments in the world.

The AMI 1.0 system consists of approximately 1.4 million smart meters across a hybrid network of both "mesh" and "cellular point-to-point" systems. Mesh meters, comprising the overwhelming majority of meters deployed by Hydro One, send data to their respective Head End System (HES) through meters, repeaters and collectors. The collectors send data back to Hydro One over cellular networks. Cellular point-to-point meters send data directly to their HES through cellular networks.

The AMI 1.0 network covers the vast majority (97%) of Hydro One distribution customers, however there are still gaps in coverage due to a combination of factors including lack of a viable backhaul technology, low customer density where the cost to connect is not economic, and AMI 1.0 technology limitations.[1] Coverage is provided by three distinct AMI vendor systems (Trilliant, Honeywell, and Sensus). The primary Trilliant system serves the overwhelming

[1] Hydro One has received a TOU exemption to 2024 (EB-2019-0259) for approximately 94,000 hard to reach customers.

majority of customers. Through LDC acquisitions, Hydro One also operates a Sensus system (serving customers of the former Norfolk Hydro and Haldimand Hydro service territories), and a Honeywell system (serving customers from the former Woodstock Hydro). Figure 1 illustrates AMI 1.0 network coverage by vendor.

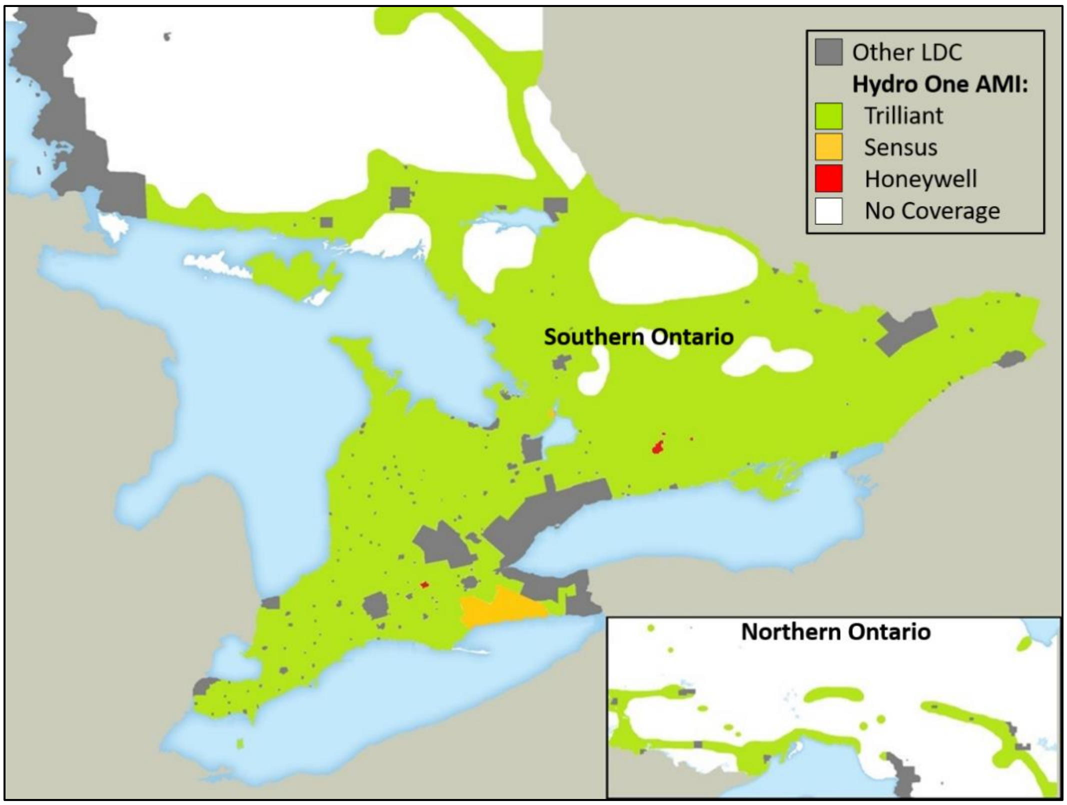

Figure 1: AMI 1.0 Network Coverage by Vendor

All of these first-generation AMI systems are not compatible and cannot operate in an integrated fashion.

Table 1 provides an overview of the number of AMI 1.0 network devices by communication technology. Hydro One owns and operates a population of approximately 1.4 million meters, 11,000 collectors, and 40,000 repeaters. The overwhelming majority of AMI meters and network devices (95% of meters, and almost 100% of collectors and repeaters) are supplied by Trilliant.

Table 1 - AMI 1.0 Network Devices by Communication Technology (2019)

Meter Communication Technology	Meters		Collectors		Repeaters	
	(#)	(%)	(#)	(%)	(#)	(%)
Trilliant Mesh	1,300,000	94.83	11,000	99.77	40,000	99.94
Trilliant Cellular P2P	4,000	0.29				
Sensus P2MP	43,000	3.14				
Honeywell Mesh	17,000	1.24	25	0.23	23	0.06
Honeywell Cellular P2P	5,000	0.36				
Ethernet w/modem	1,600	0.12				
Phone Line	100	0.01				
No Communication	150	0.01				
Total Devices	**1,370,850**	**100**	**11,025**	**100**	**40,023**	**100**

Hydro One's AMI 1.0 system will begin to reach the end of its 15-year service life in 2022. As the system ages, meter failures (primarily the loss of the ability of the meter to communicate) have increased beyond standard operating levels and meters are showing conditions of disrepair. Meter failure projections, based on independent testing, show 45% of the meter population failing by the end of the planning period in 2027. High meter failure rates, without intervention, pose significant and critical risks to Hydro One's operations, affecting various aspects of its business including:

- Non-compliance with provisions of Measurement Canada's *Electricity Gas and Inspection Act, 1985* and *Weights and Measures Act, 1985* and the associated risk of needing to replace meters with obsolete technology.
- Non-compliance with provisions of the OEB's Distribution System Code, 2020 with respect to billing accuracy targets and associated customer dissatisfaction due to increased estimated bills and bill corrections;
- The uneconomic reactive replacement of individual meters on a run to failure basis; and
- Adverse operational consequences associated with technological obsolescence.

This ISD is organized to present the AMI 2.0 investment need, investment description, expected outcomes, the expenditure plan including the comparison of pacing options, a comparison of alternatives, and the identification of risks and risk mitigation actions.

B. INVESTMENT NEED

B.1 INTRODUCTION

Hydro One, similar to other utilities and asset types, employs different maintenance strategies for retail revenue meters depending on the stage in the asset's lifecycle; namely normal service life and end-of-service life. Shortly after AMI installation and a period of stabilization, the AMI system enters a period of consistent performance—normal service life. In the normal meter service life stage, a cost-effective, low customer impact, run to failure approach is employed where individual failed meters are replaced with functioning meters like-for-like. Meters are replaced rather than repaired because the cost of repair (removal, shipping, lab assessing and diagnostics, repairing if feasible, resealing, and re-shipping back to the field) is higher than the cost of replacement. In the "wear out" period on the other hand, as meter digital components begin to deteriorate due to age and environmental conditions, and individual meter failures and replacement costs begin to increase due to the magnitude of the failures across the service territory, the need for more efficient mass meter replacement is assessed. This assessment is based on a combination of factors including manufacturer service life information, empirical failure trends and root causes, independent testing, and best industry practices from benchmarking and other sources. All of these inputs, discussed below, allow for the best correlation between age of device, risk of failure, and future costs.

B.2 AMI 1.0 METER SERVICE LIFE

In EB-2017-0049, the OEB directed Hydro One to explore with the manufacturer its basis for the estimated service life of smart meters and report back as part of its next filing. This information, documented in correspondence, was obtained from the vendor (Trilliant) and is summarized in DSP Section 3.3. In this correspondence, Trilliant attested that it designs its products to operate for a minimum period of 15 years. Independent laboratory analysis commissioned by Trilliant of its SecureMesh radio, the key meter component that enables it to reliably communicate, supports a minimum expected service life of 15-years. However, Trilliant does not guarantee a minimum 15-year meter service life and states that actual meter performance may differ materially from minimum service life. It recommends a conservative approach to replacing metering equipment with a meter replacement cycle that supports up to and including the 15th year of service to balance maximum service life and security of service. DSP Section 3.3, Benchmarking and other Studies, provides the results of the AMI Benchmarking Study commissioned by Hydro One involving a mix of 36 Canadian and U.S. utilities. The study found, among other things, that Hydro One was among 44% of respondents who had an expected meter service life of 15-years, which represented the mode of the group. Other industry studies also find a recommended 15-year service life to be appropriate for first generation AMI meters. The OEB commissioned Asset Depreciation Study prepared by Kinectrics Inc., for example, found that the appropriate useful life for smart meters was in the range of 5-15 years, for repeaters 10-15 years, and for collectors 15-20 years.[2] Further, the Ontario Auditor General, in its report on Ontario's smart meter initiative, also found the useful life for a typical first generation smart meter was 15 years.[3]

To further verify vendor meter service life attestations, confirm industry benchmarking data, corroborate information from other sources, and better understand root causes of meter failures, Hydro One engaged Hydro Quebec to independently design and perform Accelerated Life Testing (ALT) on Hydro One meters and report on results. ALT is the process of testing samples from a meter population and subjecting them to stressors that simulate the service life by reducing time-to-failure without introducing any new failure mechanisms. By analyzing the meter's response to such tests, predictions can be made regarding meter service life. Hydro Quebec has specialized expertise in designing and conducting ALT studies and offers a range of facilities for performing various mechanical, electrical, thermomechanical, climatic, temperature cycling, and temperature-rise testing. The study's complete findings are documented in "Accelerated Life Testing of Focus ALF meters with GEN 1 and GEN 3 Communications Boards, September 2020" summarized in DSP Section 3.3.

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[2] Kinectrics Incorporated, Asset Depreciation Study for the Ontario Energy Board, Report No K-418033-RA-001-R000, July 8, 2010.
[3] Auditor General of Ontario, 2014 Annual Report of the Auditor General of Ontario, 2014, pg. 391.

In summary, the ALT study was performed on a random sample of meters equipped with SecureMesh GEN1 and GEN3 communications boards. GEN 1 meters were the vendor's first meter design installed in the 2007-2009 period and GEN 3 meters were the vendor's subsequent design installed in the post 2009 period. Together, GEN 1 meters (661,000) and GEN 3 meters (476,000) make up 80% of the meter population. The most significant study finding, upon completion of meter testing, identified critical failures in GEN 1 meters involving the rapid degradation of the Capacitor (C21) that enables the meter to reliably communicate. More specifically, the study found that the C21 capacitor in 18 of 19 meters analyzed reached the manufacturer end of service life specifications which lead to complete meter communication failure in 14 of the 19 meters.

Figure 2 below provides the projected accumulated GEN 1 meter failures by year based on the appropriate ALT study Acceleration Factors and Time to Failure (TTF) results at the 50% confidence level.[4] Hydro Quebec recommends the use of the 50% confidence level, also known as the median rank, which provides a balanced assessment for the probability of failure and the closest value to the actual results observed during testing.

[4] Calculations are calibrated to reflect the appropriate rate of deterioration of meters located in the areas approximating the Sudbury climatic region (15%) and the Windsor climatic region (85%).

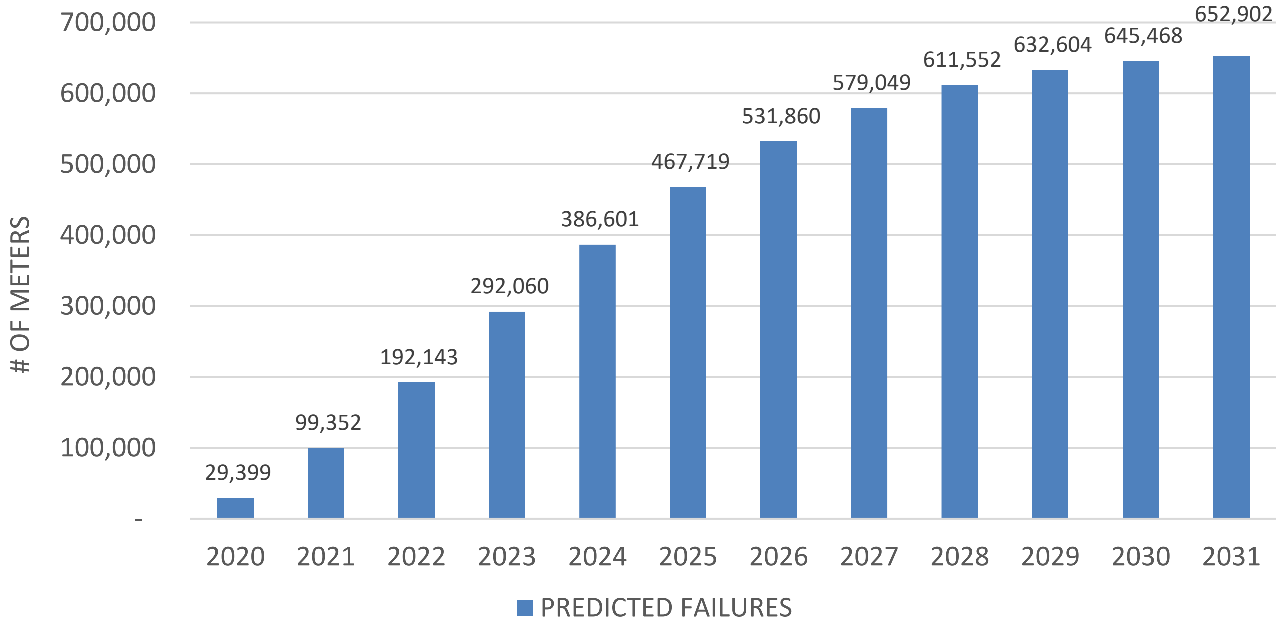

Figure 2: Projected Accumulated GEN 1 Meter Failures Based On ALT Results at the 50% Confidence Level

Accumulated meter failure projections at the 50% confidence level show 88% of GEN 1 meters (579,000 meters) are projected to fail by the end of 2027, representing 45% of Hydro One's total meter population. While the actual number of projected GEN 1 meter failures is valuable and important, most significant is the finding of the rapid and deteriorating condition of GEN 1 meters which was unknown, affirming vendor, benchmarking, and other industry studies of a 15-year service life for Hydro One's AMI 1.0 meters.

B.3 CONDITION OF ASSETS

Similar to other types of solid state computing and telecommunications equipment, the need for replacing AMI systems is driven by two interrelated factors: 1) physical mortality factors; and 2) technological obsolescence. These factors are discussed below.

PHYSICAL CONDITION

Meter age and meter failures are key indicators of the health of the retail revenue meter population. Figure 3 below provides the age of meters by year by vendor for the meter population. Approximately 840,000 meters (65% of the meter population) are between 11-13 years old and will begin to reach the end of their 15-year service life in 2022.

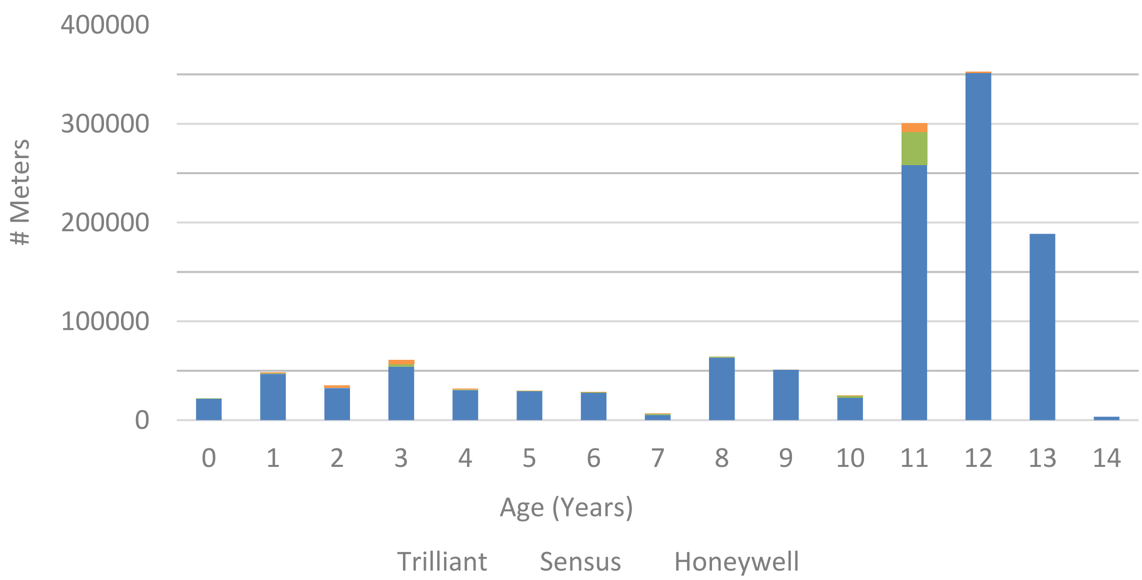

Figure 3: Meter Age Distribution by Year: 2020

Figure 4 presents the annual volume of meter failures for the period 2017-2020.[5] Meter failures have close to doubled over this period, from 11,500 meter failures in 2017 to 22,600 meter failures in 2020.

[5] Meter failure data began to be reliably collected in 2017.

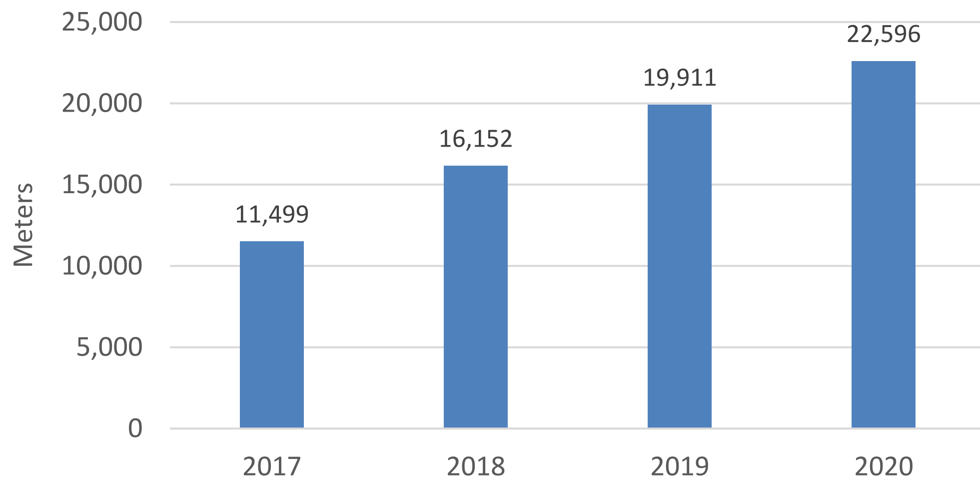

Figure 4: Annual Trilliant Residential Meter Failures: 2017-2020 (L&G ALF Meter)

Figure 5 below illustrates the failure rates of meters by their age. The data shows that older meters are failing at a greater rate than newer meters, with the oldest population of meters (13 and 14 years old) failing at a rate of 4% and 6% per year respectively.

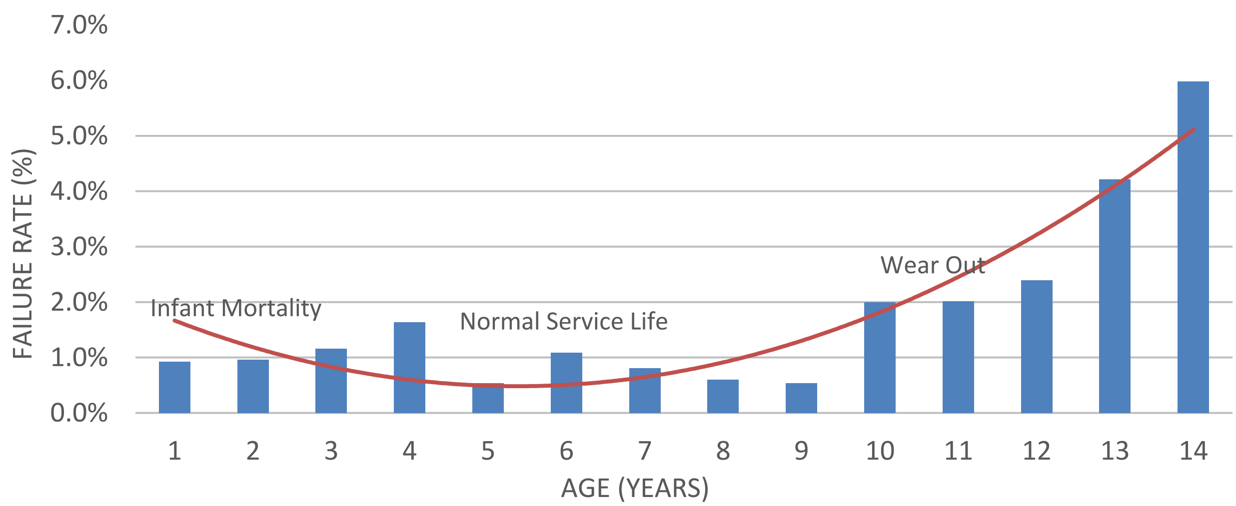

Figure 5: 2020 Failures By Age (Residential Meters)

The polynomial trend line (in red) applied to the meter failure rates exhibits a classic product lifecycle “bathtub curve”, a common reliability engineering term describing a product’s failure characteristics over its service life, comprising three discrete periods:

- An infant mortality period in the early years with a decreasing failure rate;
- A normal life period with a low, relatively constant failure rate; and
- A wear out period exhibiting increased failures as the population reaches end of service life.

The meter trend line indicates that older meters (13 and 14 years old) are entering their "wear out" period with increasing failure rates.

Hydro Quebec, as part of its ALT study discussed previously, performed an analysis of failed meters to better understand failure mechanisms. Testing included accuracy tests, communication tests, load profile and register verification, LCD discolouration measurement, super capacitor characterization, and electronic circuit analysis. The analysis found multiple physical condition issues causing the meters to fail including:

- Electrolyte leakage from capacitors preventing meters to communicate;
- Transformer failures cutting power supply to the meter;
- LCD component failures resulting in corrupted displays or no display at all; and
- Cracked solder joints connecting the metrology board to the communication board impacting meter communication.

Figures 6, 7, and 8 provide illustrative examples of the deteriorating physical condition of meters and failure modes.

Figure 6: Capacitor Electrolyte Leakage

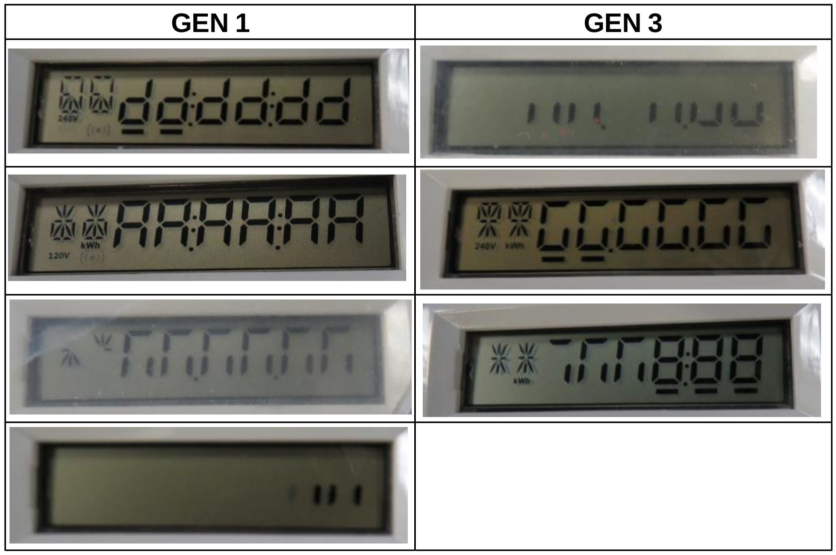

Figure 7: Meter LCD Failures

Figure 8: Cracked Solder Joints

TECHNOLOGICAL OBSOLESCENCE

Unlike traditional electromechanical meters, AMI systems are complex and subject to both physical mortality (discussed above) and technological obsolescence factors. The Ontario Auditor General, in its report on Ontario's smart meter initiative, found a 15-year service life estimate for meters is likely overly optimistic given technological obsolescence considerations.[6] AMI systems, in general, are subject to significant technological changes and are similar to other

[6] Auditor General of Ontario, 2014 Annual Report of the Auditor General of Ontario, 2014, pg. 391

types of information technology requiring significant upgrades or more frequent replacement as the technology matures. However, unlike other forms of information technology, it is not viable to physically update installed meters given the significant volume of devices, their geographic distribution across the service territory, and their sealed nature. In this regard, Hydro One is experiencing multiple conditions of technological obsolescence with its AMI 1.0 system, which in turn lead to operational challenges and costs including:

- Short notice product de-listings and the related effort to test and approve replacement products;
- Reduced vendor support for older technology and unavailability of original parts;
- The modernization of supporting third party technology (e.g., upgrades from telecom providers from Code Division Multiple Access (CDMA) to Long Term Evolution (LTE) rendering first generation AMI 1.0 network equipment incompatible; and
- Lost opportunities for benefits and efficiencies associated with advancements in AMI technology since 2007 including improved network reliability and coverage, additional features, and AMI platform enhancements (e.g. enhanced meter memory and increased network capacity) to address foreseeable future needs (e.g., increased adoption of distributed energy resources such as distributed generation, battery storage, and electric vehicles).

B.4 REGULATORY COMPLIANCE CONSIDERATIONS

ELECTRICITY GAS AND INSPECTION AND WEIGHTS AND MEASURES ACTS

The *Electricity and Gas Inspection Act, 2004* requires all meters be verified through a sampling program at specified intervals in order to ensure a customer's electricity usage is metered accurately. Once a meter seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended through compliance sample testing, or be replaced. Approximately 590,000 meters, or 43% of the total meter population will have their seals expire between 2023 and 2027 and require compliance sample testing (involving testing a smaller sample group as per Measurement Canada specifications). As a result, in the absence of intervention, sample testing will need to occur on 43% of the meter population that will have reached or exceeded the end of their service life. This poses a risk of potentially needing to replace thousands of meters with obsolete AMI 1.0 technology should a sample fail.

The *Electricity Gas and Inspection Act* also requires meters be kept in a condition of "good repair" and the *Weights and Measures Act* and related regulations require devices be maintained in proper operating condition. In this regard and as discussed above, the meter population has begun to show conditions of disrepair including LCD failures, resulting in field personnel and customers being unable to read meters manually. Although Hydro One has received a limited exemption from Measurement Canada to continue to operate meters with faulty displays manufactured between 2008 and 2011 to extend their service lives, there are no assurances exemptions would be applied to meters manufactured in other periods, and Measurement Canada has directed Hydro One to otherwise immediately replace meters with faulty displays when found in-service[7]. As meters age beyond their designed service life and deteriorate due to age and environmental conditions, there is an increasing risk of non-compliance with good repair provisions of the *Electricity Gas and Inspection* and *Weights and Measures* Acts, and related regulations.

ONTARIO STANDARD SUPPLY SERVICE CODE AND DISTRIBUTION SYSTEM CODE

The OEB *Standard Supply Service Code, 2020*, together with the OEB *Distribution System Code*, set out the obligations Hydro One must meet in regard to billing retail customers. In this regard, Hydro One is obligated to bill its customers on both Regulated Price Plan Time-of-Use and Two-Tier rates, and must issue customers no more than 2 estimated bills every 12 months, and issue an accurate bill 98% of the time on a yearly basis. The DSC defines an accurate bill as a bill that contains correct customer information, correct meter readings, and correct rates. A bill is considered inaccurate if: a) the bill has been issued to the customer and subsequently cancelled

[7] Exemption Letter from Measurement Canada: Deficient Indicating Display on L+G Focus Meters (MC NOA AE-1559), May 18, 2016. Guy Dacquay, Manager, Utility Metering Division, Measurement Canada.

due to a billing error; or b) there has been a billing adjustment in a subsequent bill as a result of a previous billing error.

Billing accuracy, as defined above, is a function of the general performance of the AMI network overall, the number of individual meter failures (and the impact of those individual meter failures on neighbouring meters due to the nature of the mesh network), and the related ability to replace meters and/or perform unscheduled manual meter reading in time to avoid an estimated bill. As meter failures continue to increase as discussed above, and the associated volume of field work in replacing individual meters and unscheduled manual meter reading continues to increase, the risk of inaccurate bills and non-compliance with DSC billing reliability standards will also increase without significant intervention. In the 2017-2019 period, field work associated with meter issues increased by 47% (23,383 to 34,274 field visits) with a $1M increase in costs.

B.5 SUMMARY OF INVESTMENT NEED

In summary, given vendor attestations, observed meter failure trends, industry benchmarking and other studies, independent ALT study results, the condition of assets (both physical and technological), and regulatory compliance considerations, Hydro One considers it prudent to plan based on a 15-year service life for its AMI 1.0 meters. Increasing meter failures pose impacts and critical risks to Hydro One, affecting various elements of its business, including:

- Reduced billing reliability from individual failed meters resulting in compliance risk and customer dissatisfaction from estimated bills and bill corrections;
- Weakened local mesh communication networks potentially impacting billing reliability of functioning meters;[8]
- Increasing field work and associated costs as a result of unplanned individual meter replacements and unscheduled manual meter reading;

[8] Individual failed meters can result in a weakened local communication networks as neighbouring meters are dependent on each other for reliable communication.

- Higher labour costs for individual meter replacements relative to mass meter replacements;
- Higher unit meter costs relative to peers as a result of lower volume purchases relative to bulk purchases associated with mass meter replacements;
- Replacement of failed meters with obsolete technology;
- Lost opportunities for operational and customer service benefits associated with up-to-date technology and being in a position to respond to foreseeable emerging trends over the new system's 20-year service life ; and
- Non-compliance with the Federal *Electricity Gas and Inspection* and *Weights and Measures Acts*, and the OEB's *Distribution System Code*.

C. INVESTMENT DESCRIPTION

C.1 INTRODUCTION

This section of the ISD provides a description of the AMI 2.0 program investment including its functionality, scope, and implementation approach. The program, given its significance and duration, is described in its entirety over the pre-test, test, and post-test periods.

The AMI 2.0 program's primary goal is to replace Hydro One's current and increasingly failing Advanced Metering Infrastructure in an economic and operationally optimal manner, and thereby maintain compliance with regulatory metering and billing requirements under the federal *Electricity Gas and Inspection* and *Weights and Measures* Acts, and the OEB's *DSC* and billing provisions of *SSSC*. The need to replace AMI 1.0 infrastructure also creates benefits and opportunities as there have been significant advancements in the technology since the AMI 1.0 system was commissioned close to 15 years ago. AMI 2.0 is a foundational investment in a modern AMI platform to address foreseeable needs over its 20-year service life.

C.2 AMI 2.0 SOLUTION OVERVIEW

Hydro One launched its competitive RFP process for a new AMI 2.0 system in 2020 and the process is expected to be complete in Q3 2021 (see Section C.3 below). Vendor responses to the RFP provided the same general solution capabilities and these are described below.

The AMI 2.0 solution will include equivalent core functionality to that of the AMI 1.0 system (i.e., automated meter reading at time-based intervals, drive by meter reading, "last gasp" notification to support outage management/restoration, etc.) and functionality associated with a modern AMI platform. The system's capabilities will be in alignment with functions that comparable utilities are seeking in their next generation AMI systems (see DSP Section 3.3). More specifically, the AMI 2.0 solution will include the following characteristics and features:

- A 20-year service life, warranted by the vendor, which is consistent with deployments in other jurisdictions (e.g., Duke Energy, Southern California Edison, DTE)[9] and in Canada (BC Hydro, Hydro Quebec, EPCOR).[10]
- Employ a communication network utilizing the 900 MHz frequency band (as opposed to the 2.4 GHz band utilized by AMI 1.0). The 900 MHz band has the advantage of improved range even with clutter (e.g., foliage, hills, buildings, etc.). This advantage is significant as it results in a reduction in the amount of equipment required for a healthy mesh network, and is expected to increase the number of customers that can be reached by the network.
- Based on Wi-SUN[11] Alliance standards-based hardware and software enabling interoperability. The system's open standards, combined with the network's ability to perform over-the-air firmware upgrades to support future standards, will enable Hydro One to avoid stranded assets and keep the platform current for the life of the system.
- Employ enhanced security to protect data against cyber and other security threats.

[9] Ameren Illinois AMI Cost Benefit Analysis Exhibit 6.2, 2012, pg. 6.
[10] Nova Scotia Power AMI Capital Project Application CI 47124, 2017, pgs. 60-61
[11] The Wi-Sun Alliance is working toward a standard for AMI, when completed, will enable utilities to buy hardware/software from any Wi-Sun vendor. This allows flexibility for a utility to change vendors without re-vamping their entire AMI system.

AMI 2.0 will also have the ability to address the needs of customers in the future and over the course of the asset's expected 20-year service life, including customers' potential future use of Distributed Energy Resources (DERs), consumer connectivity and use of mobile devices, and carbon reduction initiatives associated with climate change.[12] The AMI 2.0 platform will allow Hydro One to accommodate foreseeable customer needs over the life of the investment as follows:

- meters incorporate embedded computing power, additional measurement capability, and more granular levels of sensing capability and storage. This supports the integration of DERs by providing visibility across the network to end points, providing availability, status, condition and the ability for control capabilities needed to maintain the integrity of the distribution network;
- meters are equipped with standards-based local area network communications which can integrate with customer smart devices and in-home controllers to reduce consumption and shift demand securely and conveniently;
- all residential meters will be equipped with a 200 amp disconnect switch with "over the air" control capability resulting in reduced truck rolls, quicker customer reconnections, and reduced bad debt costs;[13]
- the secure communication network has higher bandwidth and can support exponentially higher volumes of information from meters and other devices, such as sensors, providing the opportunity to converge metering and distribution automation networks to reduce duplication and costs;
- the AMI 2.0 platform supports an environment for the creation of Applications (similar to consumer smart device "apps") to improve customer service, enable more convenient energy management, and to better manage grid operations;

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[12] Examples of Regulatory Initiatives to address these emerging technologies and the issues associated with them include: OEB Utility Remuneration (EB-2018-0287) and Responding to Distributed Energy Resources (EB-2018-0288); New York State, Reforming the Energy Vision (2014); California Public Utilities Commission DER Action Plan (2017). Michigan Public Service Commission, MI Power Grid, 2019.
[13] Currently, only 1% of AMI 1.0 meters include remote disconnect/reconnect functionality

- At the customer's option, AMI 2.0 functionality provides the opportunity to detect existing and new customer loads (e.g., individual appliances, electric vehicles, etc.) and present information on smart device applications to better manage usage and take advantage of pricing options;
- Meters have the capability to identify faulty customer equipment (e.g., meter base installations) or faulty distribution equipment (insulators) to improve customer safety and distribution system operations.
- The AMI 2.0 platform provides the capability for meter locational awareness where meters are aware of their connection to the distribution grid as well as their connected neighbouring meters. This information can be used to ensure the accuracy of the distribution utility connectivity model (the location and connection of assets across the distribution system) and improve the operation of the system.

The AMI 2.0 program will allow Hydro One to implement these functions over the life of the system provided the functions are prudent and address identified customer needs or reasonable system improvements. These functions would not be possible with the existing AMI 1.0 or equivalent system.

C.3 AMI 2.0 WORK SCOPE

The AMI 2.0 program is a multi-year investment organized over three sequential phases: Pre-Deployment request for proposal (RFP); Planning, HES and Pilot; and Mass Deployment (outlined below in table 2). This section of the ISD describes the work program scope by program phase.

Table 2 - AMI 2.0 Program Work Scope Overview

Phase	Pre Filing			**Filing Period**					Post Filing	
	2020	2021	2022	**2023**	**2024**	**2025**	**2026**	**2027**	2028	2029
1. Pre-Deployment										
2. HES and Pilot										
3. Mass Deployment										

PHASE 1: PRE-DEPLOYMENT RFP (2020-2021)

The Pre-Deployment RFP phase of the program, initiated in the Pre-Filing Period, is outlined in Table 3 below. It focussed on the competitive procurement of a new AMI 2.0 system and the establishment of a Program Management Organization. Initiating the RFP process in 2020 was necessary due to the lead times required to execute the program and address the risk of accelerating AMI 1.0 meter failures.

Table 3 - Phase 1: Pre-Deployment RFP

Activity	**2020**				**2021**			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
RFP Requirements Gathering								
RFP Preparation								
RFP Release								
Technical Review								
Secondary Technical Evaluation								
Negotiations								
Hydro One Board Approval to Enter into a Contract with Selected Vendor							→	
Establish PMO								

AMI 2.0 RFP

The AMI 2.0 RFP, released in 2020, followed Hydro One's established guidelines and processes to ensure quality, fairness, and due diligence when engaging third party suppliers. The material goods and services proposed to be procured in the AMI 2.0 investment included the AMI 2.0 hardware and software (meters, collectors, repeaters, and HES) and vendor professional services. To optimize the procurement process, share best practices, and leverage buying power for the benefit of customers, Hydro One entered into a joint RFP process with Alectra Utilities. Under this process, administrative aspects of the RFP were performed jointly but the evaluation and selection of a preferred vendor were conducted independently by each party. In the event Hydro One and Alectra independently select the same vendor, price benefits occur through combined purchase volumes.

A prudent phased program approvals approach will begin in Q3 2021 with Hydro One Board approval to enter into a contract with the preferred AMI 2.0 vendor (for meters, network equipment, HES, software licences, and professional services), followed by approvals at appropriate program release stages, in accordance with Hydro One governance processes and authorities.

Establish Program Management Office (PMO)

A long-term significant initiative such as AMI 2.0 involves resourcing for program management, planning, and delivery activities designed to ensure quality implementation across each solution component. Hydro One follows accepted program management best practices. This includes the establishment of a Program Management Office (PMO) which will remain in place for the duration of the project. The PMO establishes program deliverables, which are tracked based on established schedules and budgets and provides for the overall management of program controls. These include activities related to program governance and the management of schedule, cost, resources, vendors, issues, risk, quality and implementation. It will include the overall coordination of procurement activities as well as vendor management. Additionally, program quality assurance and audit will seek to confirm that the program is compliant with internal and external standards. More specifically, program management activities include:

- Governance: Oversight, prioritization, approvals, establishing sponsorship and accountabilities;
- Quality Management: The establishment and management of practices to manage quality across the program;
- Program Scheduling and Staffing: The management of integrated timelines and dependencies; securing and allocating resources;
- Issue and Risk Management: A standard methodology for assessing, prioritizing, and escalating issues to ensure timely resolution; the development and management of risk identification and response capabilities to manage risk across the program;
- Program Communications and Reporting;
- Change Control Process: The management and prioritization of new requirements, including change orders;

- Release Management: The management of an integrated release strategy to support organization-wide prioritization;
- Vendor and Contract Management: The management of key vendors; and
- Business Process and Employee communications: The redesign of business processes as necessary and activities to prepare employees for the new technology and business processes.

The program management function is planned to be performed by a combination of internal and external resources.

PHASE 2: PLANNING, HEAD END SYSTEM (HES) IMPLEMENTATION AND PILOT (2022-2023)

The Planning, HES and Pilot phase of the program, to be implemented in 2022-2023, is outlined in Table 4 below. It involves a limited amount of program planning; testing and certification of AMI 2.0 meters and network devices; the design, installation, and integration of the HES; and the procurement of a small number of meters and network equipment to conduct an end-to-end pilot of the solution.

Table 4 - Phase 2: Planning, Head End System (HES), and Pilot

Activity	2022				2023			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Operational Preparedness Planning	■	■	■	■	■	■		
HES Design, Build, Integrate, Test			■	■	■	■		
HES Go-Live						■		
Pilot Network Deployment							■	
Pilot Meter Deployment								■
Pilot Monitoring								→

Operational Preparedness Planning

Upon the selection of the AMI 2.0 vendor and the establishment of the PMO, operational preparedness planning will occur involving new product testing and certification, hardware logistics, pilot scoping, deployment strategy and planning.

Head End System (HES)

The HES is the back-office software system where all of the meter and network information is sent and managed before being distributed to other internal IT systems (e.g. Customer Information System), as well as to the Independent Electricity System Operator's Meter Data Management Repository (MDM/R). This stage of the program involves implementing a structured approach to designing, building, integrating, and testing the HES.

AMI 2.0 Pilot

The AMI 2.0 pilot stage, involving 3,000-4,000 meters and a small amount of network equipment, will be planned in 2022 and implemented in 2023 upon HES "go live". The pilot will allow Hydro One to:

- Gain operational experience with AMI 2.0 in advance of mass deployment;
- Develop the processes required to cost-effectively scale up to mass deployment; and
- Identify best practices in minimizing customer impacts associated with transitioning from AMI 1.0 to AMI 2.0.

PHASE 3: MASS DEPLOYMENT PRE-INSTALLATION PLANNING AND IMPLEMENTATION (2023-2028)

The mass deployment of network equipment and meters is a multipart activity involving pre-installation planning, network design activities, field deployment, and customer communications outlined in Table 5 below.

Table 5 - Phase 3 Mass Deployment Pre-Installation Planning and Implementation

Activity	**2023**				**2024-2028**			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Pre-Installation Mass Deployment Planning						→		
Network Design and Tuning				→				
Network Deployment								→
Mass Meter Deployment								→
Customer Communications								→

Pre-Installation Mass Deployment Planning

During the pre-installation planning stage, facilities are prepared for AMI meter processing, field surveys are completed, and plans are developed for mass meter deployment including setting up cross-dock facilities as logistical hubs. The workforce is trained, meters are sample tested for performance, and meters are shipped to logistical hubs in advance of mass deployment.

Network Design

AMI communications network design involves planning the location of Repeaters and Regional Collectors in the field. Network design and deployment occurs ahead of meter deployments and involves cycles of validating vendor-selected locations for network equipment through both paper and field scouting processes.

Network and Meter Deployment

Once a network design is finalized for a geographic area, network devices are installed and verified. Figure 9 below provides the projected network hardware deployment by year.

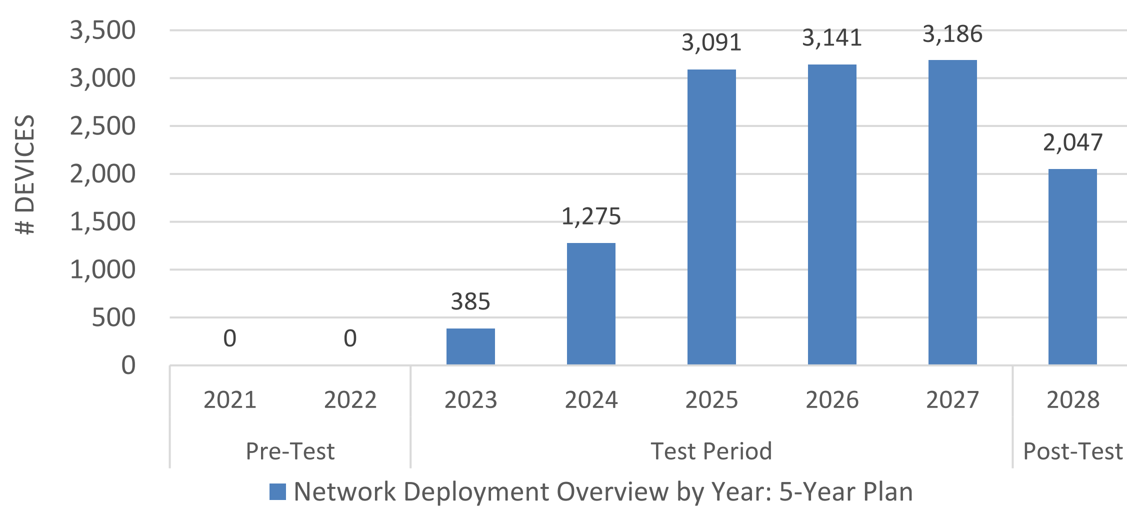

Figure 9: Network Deployment Plan

Once network hardware is installed in a geographic area, installers are scheduled to mass replace meters. Figure 10 below outlines the Meter Deployment Plan by year.

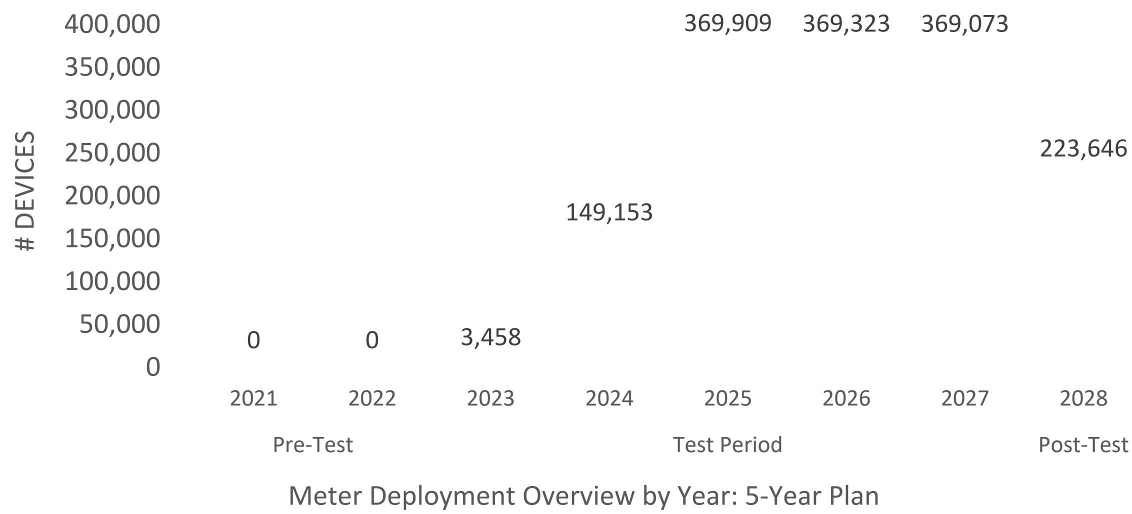

Figure 10: Meter Deployment Plan

The plan involves the mass replacement of approximately 150,000 meters in 2024 (providing a ramp up period to accommodate the incorporation of lessons learned from the pilot); the sustained mass deployment of approximately 370,000 meters per year from 2025 through 2027; and ramping down to completion in 2028 with the installation of approximately 224,000 meters.

The meter installation process involves informing the customer of a short power interruption, removing the AMI 1.0 meter, replacing it with a new AMI 2.0 meter, and registering the new meter for the customer premise (a process that typically occurs in minutes). Tests of meter communication are performed as part of commissioning, a monitoring and triage process occurs to identify meters that may not immediately associate with the communication network, and in such cases, manual meter reading would occur until the condition is addressed.

Customer Communications and Customer Service

A customer communications /education strategy will be prepared and implemented to support the mass meter deployment plan. The deployment of AMI 2.0 is expected to result in improved meter communication reliability for some customers. In such cases, customers' currently purchasing electricity under Regulated Price Plan (RPP) Two Tier Prices will have the option to convert to RPP Time-of-Use prices. The customer decision to transition may be made once a meter communication reliability threshold assessed over at least a 1-year period (to account for meter communication seasonality) is achieved. Once the meter achieves the required threshold, the customer will be informed of the improvement in meter communication and their option to convert to Time-of-Use prices.

D. OUTCOMES

The AMI 2.0 program will:

- Maintain reliable operation of metering infrastructure by replacing the failing AMI 1.0 system that has reached the end of its service life;
- Replace AMI 1.0 in an economic and operationally efficient manner through mass, as opposed to reactive, replacement;
- Maintain compliance with regulatory metering and billing requirements under the federal *Electricity Gas and Inspection* and *Weights and Measures Acts*, and the OEB's *Distribution System Code* and *Standard Supply Service Code*;
- Maintain billing accuracy and minimize estimated billing and bill corrections;
- Improve customer service through increasing the number of customers on the AMI network and providing faster response times for some types of disconnection/ reconnection requests;
- Improve operational effectiveness and efficiency (e.g., reduction in field visits for manual meter reading and disconnection/reconnection requests, reduction in network management and data backhaul costs, reduction in IT HES costs, provision of new data sets for operational decision-making, etc.); and
- Provide a modern AMI platform to meet foreseeable customer and operational needs over the system's 20-year service life.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 6 - Outcome Summary

Customer Focus	Contributes to Hydro One's customer service goals by: • Maintaining billing accuracy and minimizing estimated billing and bill corrections; • Improving network communication reach by providing an expected increase in the number of customers with access to optional TOU prices and related customer tools (e.g., internet-based access to hourly usage information) to better manage their electricity use and bills; • Providing faster response times to some types of disconnection/reconnection requests; • Providing enhanced end-to-end data protection employing the most modern advancements in security architecture; • Providing a modern AMI platform to meet foreseeable future customer needs.
Operational Effectiveness	Contributes to Hydro One's operational effectiveness goals by: • Maintaining reliable operation of metering infrastructure by replacing equipment that has reached the end of its service life; • Reducing resource requirements for manual meter reading; • Increasing efficiency and safety through reduced field visits for manual meter reading and disconnection/reconnection requests; • Increased efficiency in managing service contracts and inventory by moving from multiple hardware and software vendors to a single vendor; • Maintains operational efficiencies enabled by AMI 1.0 (see DSP Section 3.3, attachment 8); and • Provides for future new data sets to improve system visibility, enhance control, and support analytics for more informed and timely planning and operational decision making.
Public Policy Responsiveness	Contributes to public policy responsiveness through: • Compliance with OEB *Distribution System Code* (March, 2020) s. 5.1 and 7.11 requirements for metering services and billing accuracy; • Compliance with OEB *Standard Supply Service Code* (Oct. 2020) s.3.1 and 3.5 provisions for rates and consumer RPP pricing options; • Compliance with various provisions of the *Electricity and Gas Inspection Act*, R.C.S 1985, and related regulations with respect to Hydro One obligations for ensuring meter accuracy and ensuring meters are in good repair; • Compliance with various provisions of the *Weights and Measures Act*, R.S.C. 1985, and related regulations with respect to Hydro One obligations for ensuring meter accuracy and meter maintenance; • Compliance with OEB direction to transition customers to time-of-use pricing, where economically viable; and • Compliance with OEB Distribution System Code Section 4.2 regarding disconnection and reconnection process.
Financial Performance	Contributes to Hydro One's financial performance by: • Reducing network management and data backhaul costs as a result of the need for less network equipment; • Reducing IT costs as a result of reducing the number of HESs; • Reducing manual meter reading costs as a result of employing a more effective 900 MHz system; • Reducing meter and labour costs relative to individually replacing AMI 1.0 meters; and • Reducing field work costs as a result of the deployment of remote disconnect/reconnect functionality.

E. EXPENDITURE PLAN

E.1 INTRODUCTION

This section of the ISD describes two alternative mass deployment pacing options and assesses the quantified and unquantified trade-offs between them. Option 1 involves mass deploying AMI 2.0 meters and network equipment over a 5-year period and option 2 involves mass deploying AMI 2.0 equipment over a 7-year period. Both options incorporate common cost inputs for key cost drivers.[14] A comparison of the options, summarized below, shows the total costs of option 1 (the recommended plan) to result in total savings of $58.0M over option 2 (the 7-year plan).[15]

E.2 ASSESSMENT AND COMPARISON OF OPTIONS

MASS DEPLOYMENT COMPARISON

Figure 11 below provides an overview of the meter deployment plans for the two pacing options.

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[14] AMI 2.0 meter costs are based on the median meter price from RFP responses. AMI 1.0 meter costs are based on 2021 contracted prices. Meter and network mass deployment labour rates are based on Hydro One internal labour rates.
[15]Total costs in this assessment include both gross AMI 2.0 costs and applicable gross AMI 1.0 corrective maintenance costs.

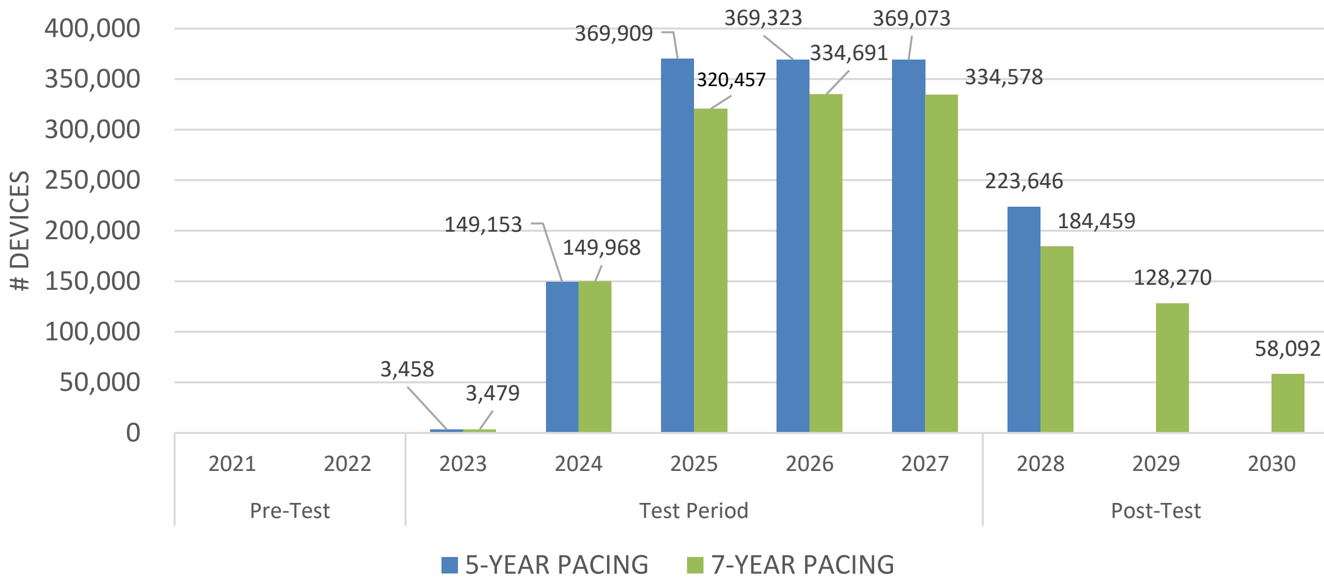

Figure 11: Mass Meter Deployment Overview: 5-Year vs. 7-Year Plan

The 5-year pacing option (option 1) involves replacing all AMI 1.0 meters and network equipment with AMI 2.0 equipment over a 5-year period beginning in 2024 through 2028. This option involves conducting an end-to-end system pilot with 3,000-4,000 meters in 2023; a one year ramp up to replacing approximately 150,000 meters in 2024; the sustained mass deployment of approximately 370,000 meters per year from 2025 through 2027; and ramping down to completion in 2028 with the installation of approximately 224,000 meters.

The 7-year pacing option (option 2) involves mass replacing all AMI 1.0 meters and network equipment over a 7-year period beginning in 2024 through 2030. Similar to option 1, the 7-year pacing option involves conducting an end-to-end pilot with approximately 3,000-4,000 meters in 2023 and a one year ramp up to replacing approximately 150,000 meters in 2024. In 2025-2027 period, there would be a sustained mass deployment of approximately 320,000-335,000 meters each year (slightly less than option 1), followed by a gradual ramp down in meter deployment from 2028 through to program completion in 2030.

TOTAL PROGRAM COSTS, COST PROFILE AND CUSTOMER PREFERENCE COMPARISON

Figure 12 provides a comparison of total AMI 2.0 total program costs for the two pacing options. Total program costs are a function of both the total AMI 2.0 gross investment costs (see Table 7) and the applicable gross corrective maintenance costs associated with replacing failed AMI 1.0 meters (see D-SA-04).

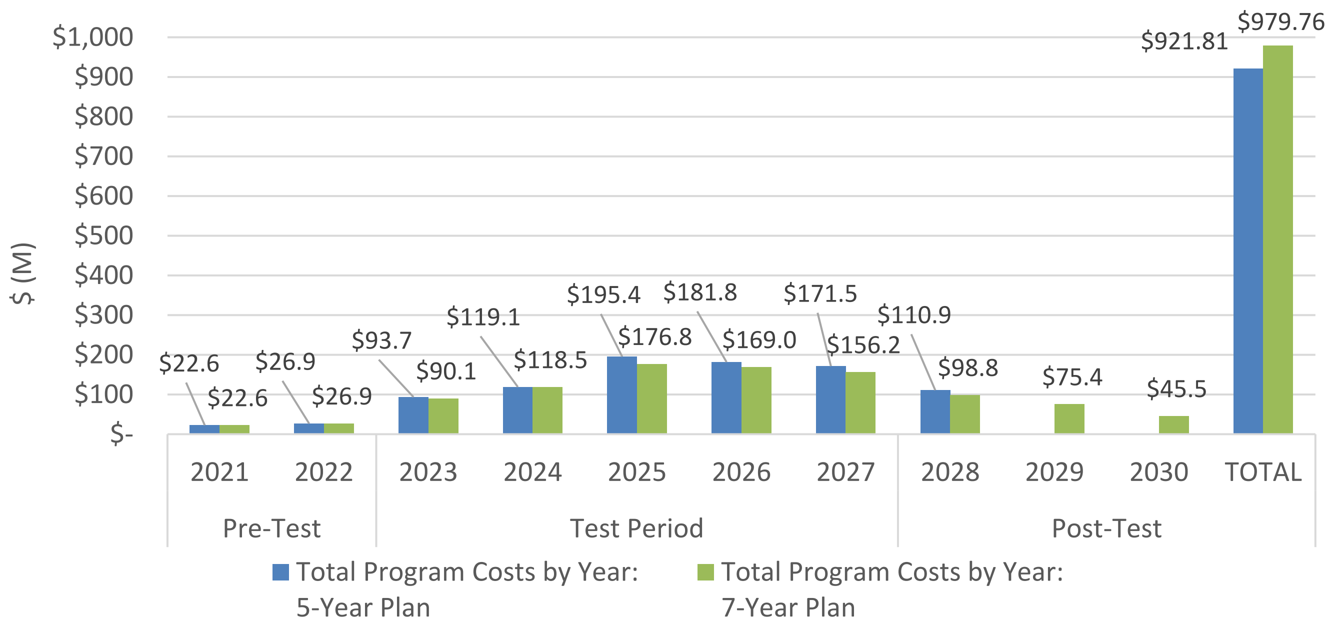

Figure 12: Total Program Cost Comparison: 5 Year vs. 7 Year Options

The total costs of the 5-year and 7-year pacing options are $921.8M and $979.8M respectively, resulting in savings of $58.0M associated with the 5-year pacing option, which requires fewer failed AMI 1.0 meters to be replaced on a reactive basis. Individually replacing meters on a reactive basis is significantly less efficient and more costly than mass meter replacements. Mass replacing meters allows for the efficient scheduling of resources and equipment in concentrated geographic areas resulting in more meters being installed in less time. Individual reactive meter replacements due to failures, on the other hand, involves travel to a single location to change a single meter. These inefficiencies are amplified in Hydro One service territory given the very low customer densities and related long travel times. These findings were discussed in the AMI Benchmarking Study. The study noted that these costs are higher than the mean of the comparator of the group because they reflected individual replacements rather than mass replacements, and because of the large, mostly low-density nature of Hydro One's service territory. Hydro One's customer density was the lowest of the group, 23 times less dense than its closest comparator.

The cost profiles of the options show the 5-year pacing option to have a lower total cost overall with a more concentrated investment in the 2023-2027 period relative to option 2 ($761.5M vs. $710.6M). This difference is driven by the higher mass deployment rates in the option 1 test period while option 2 has lower mass deployment rates in the test period but meters continue to be deployed through 2030. Consequently, option 2 would result in a lower bill impact in the test period but a higher total bill impact overall.

The Phase 2 Customer Engagement Program results (see SPF Section 1.6, Attachment 1, p. 22) found 36% of residential customers and 29% of commercial customers preferred the 5-year pacing option while 64% of residential and 71% of commercial customers preferred the 7-year pacing option. At the time of the customer engagement however, neither Hydro One nor customers had the benefit of the results of the Accelerated Life Testing study which indicated higher than expected AMI 1.0 failure rates, resulting in higher reactive replacement costs under the 7-year option and associated risks to billing reliability.

Recommended Option

Based on the above assessment, Hydro One's recommended pacing approach is option 1, the 5-year pacing option, to more effectively mitigate the higher than initially expected failure rates of AMI 1.0 meters and associated reactive replacement costs, informed by third-party Accelerated Life Testing results. While Hydro One understands the customer preference for a longer 7-year pacing approach that pushes some costs out of the 2023-2027 period, the 5 year pacing approach results in an expected $58.0M in total program cost savings. Any elevated billing reliability risk associated with the accelerated customer migration to AMI 2.0 will be minimized through implementing focused work processes to identify and address missed meter readings in in an expedited manner.

Table 7 below summarizes historical and projected AMI 2.0 spending on the aggregate investment level. The “Previous Years” costs are the direct investment costs for investments noted in Section C.3 (Work Scope) for operational preparedness planning and the design of the AMI 2.0 Head End System that have been incurred prior to the 2023 test year. Likewise, the costs noted in “Forecast 2028+” are investment costs forecast beyond the test period.

Table 7 - Total Investment Cost

($M)	Prev. Years[1]	2023	2024	2025	2026	2027	Forecast 2028+[1]	Total
Gross Investment Cost	3.9	30.9	62.0	153.7	154.4	158.3	128.0	691.2
Less Removals	0.0	0.0	0.0	0.0	0.0	1.0	0.0	1.0
Capital and Minor Fixed Assets	**3.9**	**30.9**	**62.0**	**153.7**	**154.4**	**157.3**	**128.0**	**690.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.9**	**30.9**	**62.0**	**153.7**	**154.4**	**157.3**	**128.0**	**690.2**

[1] Due to the duration of program, investments are provided for previous years, the test period, and forecast years.

Key considerations affecting the final cost of the program consist of the following:

- The pacing of AMI 2.0 mass deployment (discussed above);
- The final outcome of the RFP process and potential hardware volume price benefits associated with the joint procurement process with Alectra Utilities (see Section C.3 above);
- Expenditures have been managed through a number of actions:
    - Plans and cost estimates incorporate Hydro One’s knowledge and experience in deploying AMI 1.0; and
    - The program will employ best project management practices, including auditing, to ensure costs are well managed.

F. ALTERNATIVES

This section assesses three alternatives to conducting meter replacement:

- Alternative 1 Status Quo: Continue to replace failed AMI 1.0 meters with AMI 1.0 meters on a reactive basis;
- Alternative 2: Mass replace AMI 1.0 with a competitively procured AMI 2.0 system with the same functionality as AMI 1.0; and
- Alternative 3 (Recommended): Mass replace the AMI 1.0 system with a competitively procured AMI 2.0 system with modern functionality.

ALTERNATIVE 1: STATUS QUO

Alternative 1 would involve continuing to individually replace failed AMI 1.0 meters with functioning AMI 1.0 meters on a reactive basis. This option has been assessed on a range of factors:

- Approximately 840,000 AMI 1.0 meters (65% of the meter population) are between 11-13 years old and will begin to reach the end of their 15-year service life in 2022. This service life has been attested by the vendor and supported by numerous studies including the OEB commissioned Asset Depreciation Study prepared by Kinectrics Inc. and the AMI Benchmarking Study conducted by Guidehouse.
- The AMI 1.0 system is becoming technologically obsolete, with adverse operational consequences and costs associated with short-notice product de-listings, reducing support for older technology and unavailability of parts;
- The physical condition of AMI 1.0 meters, as identified by independent testing, are deteriorating (LCD failures, electrolyte leakage from capacitors, transformer failures, cracked solder joints, etc.);
- AMI 1.0 meter failures are trending significantly upward, with meter failures doubling between 2017 and 2020. Based on independently conducted Accelerated Life testing results, the degradation of the capacitor that enables meters to reliably communicate will result in approximately 579,000 meters failing by the end of 2027;

- The risk of individual AMI 1.0 meter failures negatively impacting local mesh networks resulting in decreased billing reliability among otherwise reliable meters;
- Individually replacing meters on a reactive basis is costly and inefficient relative to mass replacement (see Section E above);
- Hydro One’s average AMI 1.0 meter acquisition costs were found to be higher than the comparator group in the AMI Benchmarking Study, partly reflecting contracted prices for low volume individual meter replacement that did not incorporate economies that would be expected with bulk meter purchases;
- Increasing AMI 1.0 meter failures result in the increasing risk of customer dissatisfaction because of billing estimates and corrections;
- The status quo option poses increasing levels of regulatory compliance risk including:
    - Risk of non-compliance with achieving Distribution System billing reliability requirements;
    - Risk of non-compliance with Measurement Canada good repair and maintenance provisions under the *Electricity Gas and Inspection and Weights and Measures Acts;* and
    - Risk of sample testing meters exceeding their 15-year service life not passing tests and potentially needing to replace thousands of meters with obsolete technology.
- The status quo option would result in lost opportunities for operational and customer service benefits associated with a modern AMI 2.0 platform and the inability to respond to foreseeable emerging needs.

Taken together, the above factors make evident that the status quo of replacing failed AMI 1.0 meters on a reactive basis beyond their expected 15-year service life is not viable, not economically prudent, poses significant regulatory and customer service risk, and limits Hydro One’s ability to plan for and address foreseeable customer needs.

ALTERNATIVE 2: MASS REPLACEMENT OF AMI 1.0 WITH COMPETITIVELY PROCURED AMI 2.0 SYSTEM WITH SAME FUNCTIONALITY AS AMI 1.0

Alternative 2 would involve mass replacing the AMI 1.0 system with a competitively procured AMI 2.0 system with same functionality as AMI 1.0. This alternative addresses the inefficiencies of reactive individual meter replacements through mass deployment, and mitigates regulatory and customer service risks associated with unreliable meter communication. However, this alternative does not include the significant improvements and technological advancements that have occurred in AMI over the last 15 years discussed in Section C.2 above (e.g., cost effective remote disconnect/reconnect functionality, improved 900 MHz frequency communications to reach more customers, less network equipment to operate and maintain, etc.), nor would it have the capabilities to address future foreseeable needs over the system's 20-year service life (e.g., additional meter computing power and measurement capability, more granular levels of sensing capability and storage, greater network band-width, etc.). This alternative, in essence, would involve installing a new AMI system that is technologically obsolete at the time it is placed into service, and therefore is not considered to be a prudent investment for customers.

ALTERNATIVE 3: MASS REPLACEMENT OF AMI 1.0 WITH COMPETITIVELY PROCURED AMI 2.0 SYSTEM WITH MODERN FUNCTIONALITY (RECOMMENDED)

Alternative 3, the recommended alternative, involves mass replacing the AMI 1.0 system with a competitively procured AMI 2.0 system with modern functionality aligned with the capabilities comparable utilities are seeking in their next generation AMI systems. This alternative addresses the inefficiencies of individual reactive meter replacements through mass replacement, mitigates regulatory and customer service risks associated with unreliable meter communication, provides customers with up to date AMI capabilities, and provides a platform to address future foreseeable needs and realize benefits over the service life of the investment (see Section C.2). Initially, once fully deployed in 2028, customers will begin to realize the quantified and unquantified benefits of a modern AMI system including approximately $6.3M annual OM&A savings from reduced manual meter reading (through improvements in network reach); reduced network costs (through the reduction in telecom circuits associated with less network equipment); reduced IT management costs (associated with the reduction in Head End

Systems); and reduced field visits (associated with remote disconnect/reconnect capability on all meters). Plans to enable additional capabilities providing higher and new levels of customer service, improved distribution operations, and increased sustainability (e.g., Load Disaggregation Information Services for Customers, Meter Locational Awareness, Grid Edge Applications etc.) will be executed using prudent stage gate/governance processes including stages for proofs of concept, pilots, business case refinements, and requisite approvals.

The procurement process for AMI 2.0 is expected to be complete in Q3 2021. The down-selected vendor responses meet current customer needs and provide a modern platform to respond to future needs over the 20-year service life of the investment.

G. EXECUTION RISK AND MITIGATION

Below is a summary of specific AMI 2.0 related risks and mitigation strategies to address them.

1 **Table 8 - AMI 2.0 Implementation Risks and Mitigation**

Risk	Risk Mitigation
• Overall program execution risk	• The Program Management Organization (PMO) will establish a best practice methodology for assessing, prioritizing, and escalating issues to ensure timely resolution. • The PMO will be responsible for the development and management of risk identification and response capabilities to manage risks across the program.
• Missed meter readings and associated estimated bills/bill corrections during the transition from AMI 1.0 to AMI 2.0 as a result of inadequate network design, the need for multiple re-visits for meter changes, and potential AMI 2.0 technological issues.	• The program will consist of discrete logical phases beginning with laboratory testing and the piloting of processes and equipment. This will reduce risk, reduce planning complexity, and maximize control of the program. • Quality control testing of AMI 2.0 equipment. • Planning for potential short-term increased manual meter reading during the transition to AMI 2.0 including implementing a monitoring and triage process to ensure potential missed meter readings are identified early and addressed to minimize any potential impact to billing reliability.
• Potential for increased costs due to program delays associated with poor network design, operational issues, and incorrect planning assumptions	• Implement and test HES and pilot with small amount of equipment • Minimize operational risk by limiting the quantity of AMI 2.0 devices initially deployed to allow Hydro One and AMI 2.0 vendor to gain operational experience in advance of mass deployment. • Ensure planning/engineering assumptions are aligned with any changes to technology. • Monitor risks, issues, assumptions, and actions closely as part of governance structure.
• Potential field resource constraints	• Involve Field Management in planning process. • Complete labour forecasting early, identify constraints, and plan temporary resources accordingly.
• Reduced support from AMI 1.0 vendor for legacy network equipment.	• Implement an AMI 1.0 inventory strategy to ensure there is sufficient inventory to address AMI 1.0 failures.
• There is a residual risk of premature meter component failures as is the case with any electronic equipment.	• In addition to the standard 10-year warranty for 100% of meter and installation costs, a longer warranty period is expected to be negotiated.
• Availability of the vendor to manufacture and deliver AMI equipment in a timely manner, and the availability of qualified resources to perform the volume of replacements required.	• Due diligence performed on vendors through RFP process. • Provide procurement forecasts upfront to the vendor, maintaining ongoing discussions with the vendor regarding future supply, and managing resources with option to hire temporary staff as required.

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D-SS-01	**SYSTEM UPGRADES DRIVEN BY LOAD GROWTH**
Primary Trigger:	Capacity
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
Net Cost	98.2	76.3	127.5	76.1	100.2	478.2

Summary:

Load Growth investments address system capacity issues that arise as a result of changes to the distribution system caused by regional load growth. The trigger for this investment is system capacity. This investment addresses these capacity issues through system upgrades or modifications, resulting in the continued ability of the system to meet forecast customer demand.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One's available grid capacity determines its ability to continue to connect new customers. Available grid capacity is directly impacted by regional or localized growth – as new customers connect to the distribution system, capacity is reduced. In order to continue to facilitate growth and avoid equipment overloading or power quality issues, Hydro One plans its system to address these capacity constraints.

System capacity constraints that are caused by regional growth result in system issues characterized by power quality complaints, system inefficiencies, or thermal constraints (where system elements are being operated near, or above, their rating). Specific examples include: low voltage, feeder unbalance, and overloaded equipment such as protection devices, conductor, or substation transformers. While these constraints and the resulting system issues are common to all load growth investments, the investments associated with the Leamington area are discussed separately in section B.1 below due to their significant proportion of all load growth expenditures.

In accordance with Section 3.3 (Enhancements) of the Distribution System Code (DSC), Hydro One is required to plan and build its distribution system to accommodate reasonable forecast load growth. Therefore, Hydro One Distribution plans and executes enhancement projects to improve system operating characteristics and relieve system capacity constraints. Load growth investments cover system upgrades that are needed in response to regional growth trends requiring significant capital expenditure, scope, and lead time to address the identified capacity constraint.[1]

[1] Investments that address near-term needs that are urgent in nature but require less significant scope are addressed under Demand System Modifications (D-SS-03).

The capability of Hydro One's distribution system to accommodate forecast loading is primarily determined through the following activities:

1. Planned studies to determine future system needs to maintain service and equipment loading within acceptable limits; and
2. System impact assessments for large new load connections.

Planned studies and system impact assessments are the main 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 network's capacity to meet actual and forecast needs based on growth trends. While planned studies are typically focused on analyzing the long-term growth trends and needs in a general area, system impact assessments identify the needs that result from connections such as new subdivision developments. Load growth investments are focused on addressing the needs identified through these planned or system impact studies.

B. INVESTMENT DESCRIPTION

As detailed in D-SA-02, Hydro One Distribution is forecasting to connect approximately 18,000 new customers every year throughout the 2023-2027 period. Depending upon the location of these new connections, localized growth may lead to capacity issues on the supply feeders or distribution stations. Proposed investments to address these capacity issues typically involve the upgrade of existing stations or feeders, construction of new stations or feeders, and conversion of feeders or feeder sections to higher voltages. The optimal solution for a given area depends on the feeder configuration and the identified needs of the surrounding feeders and stations.

Typical load growth investments consist of:

FEEDER INVESTMENTS

These investments involve the redistribution of load through the construction of new feeders or the modification of existing feeders. Typically, the focus is on utilizing new or lightly loaded feeders to offload heavily loaded sections. The construction or extension of feeders may have the added benefit of improving load transfers and operational flexibility through SCADA-enabled automation of feeder ties. An alternative to constructing new feeders is voltage conversion, which can increase available capacity on the feeder by converting to a higher voltage.

EXAMPLE FEEDER INVESTMENT: "BLOOMSBURG DS NEW FEEDER BUILD"

Bloomsburg DS has experienced an influx of connection requests. The 27.6kV feeders that emanate from Bloomsburg DS (M1, M2 & M3) have a planned capacity limit of approximately 16MW per feeder. The peak loading of the M1 & M2 feeders is currently in excess of their planned capacity. Additionally, there is an area of growth directly south of Bloomsburg DS, totaling approximately 25MW in new connection requests, in the vicinity of the overloaded M1 and M2 feeders. The existing feeders and area of load growth is shown in Figure 1 below.

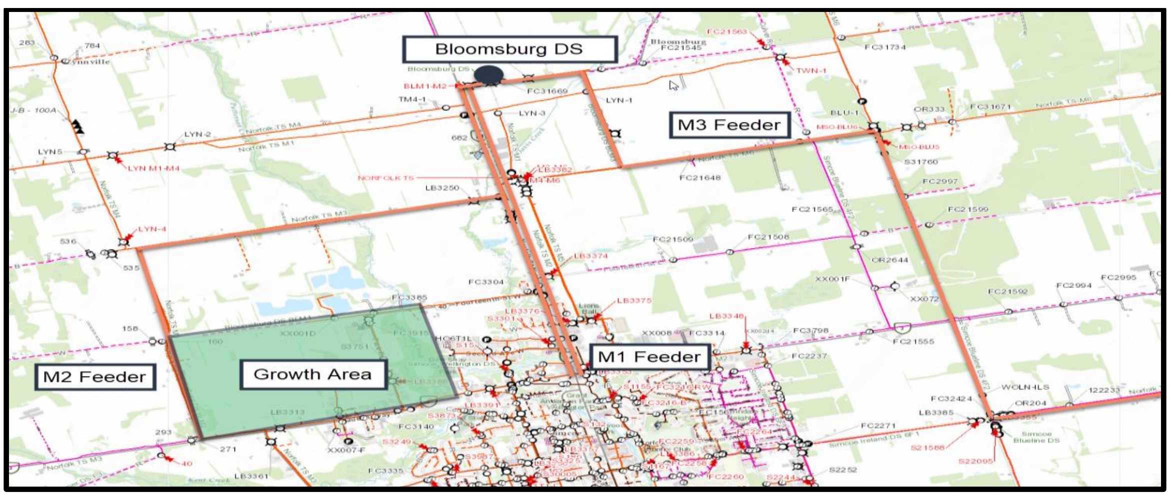

Figure 1: Bloomsburg DS feeders – Existing

Although the M3 feeder does have approximately 5MW of capacity remaining, this is insufficient to support continued growth in this area, and as can be seen, the proximity of the M3 feeder to the M1 and M2 feeders is not sufficiently close to warrant the cost of construction, considering the limited benefits. In order to address the aforementioned capacity limitations, Hydro One is planning to construct two additional feeders. The routing for these proposed feeders is shown in Figure 2 below. The new feeders will be routed south from Bloomsburg DS, and will primarily be used to address load growth. Additionally, these feeders will reduce existing loading on the

M1 and M2 to within capacity limitations, and will provide sufficient flexibility to balance load between feeders.

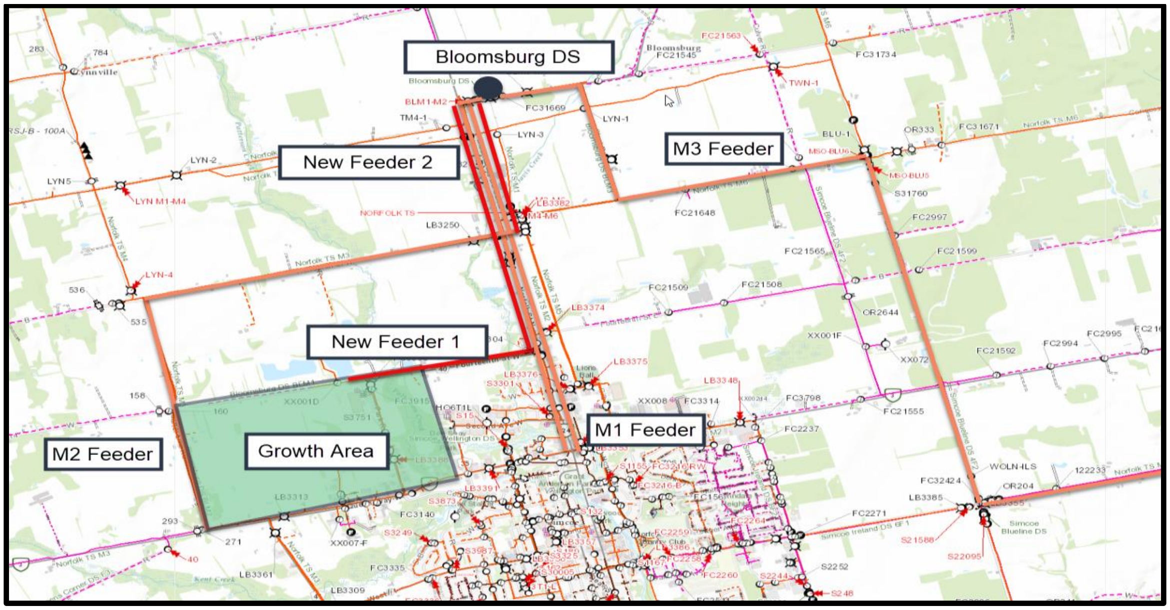

Figure 2: Bloomsburg DS feeders - Proposed

STATION INVESTMENTS

Station upgrade investments involve the modification of existing stations or the construction of new stations. If sufficient feeder capacity is available and the only identified need is an overloaded station transformer, the need can be addressed by increasing the station transformer size; installing additional transformers; or installing fan monitoring to increase the loading capability of existing station transformers. In cases where needs are identified at both the station transformer and feeder level, constructing a new station may be more effective from a cost and operating perspective than upgrading an existing station. New station construction offers the benefit of additional feeder capacity to reduce conductor loading on existing feeders, and also has the potential to improve load transfer capabilities similar to feeder reinforcement projects.

EXAMPLE STATION INVESTMENT: "SAUGEEN SHORES DS AND PORT ELGIN LOAD GROWTH"

Hydro One has received a steady influx of requests associated with the design, construction, and connection for new subdivision homes in Port Elgin, Ontario. As a result, approximately 350 lots have been connected within the last two years, and more than 1000 additional lots are planned, at a rate of ~150 lots per year. Figure 3 below shows a map with electrical overlay that details the location of existing feeders, distribution station, and growth area.

The F2 feeder that supplies the area of subdivision growth is loaded to approximately 2MVA (representing 50% of its thermal capacity), and the distribution station, Port Elgin DS, is loaded to approximately 6MVA (representing 85% of its 7MVA thermal capacity). Based on loading data, both the F2 supply feeder and Port Elgin DS have insufficient capacity remaining to support the continued subdivision growth – in total, the remaining subdivision load is anticipated to be in excess of 4.5MVA, which far exceeds the available station and feeder capacity. If Hydro One does not move forward with load growth investments in this area, the increased subdivision loading will exceed the rating of the distribution station transformer, feeder conductor, and protection devices resulting in an increased likelihood of asset failure and power quality issues.

In order to accommodate the anticipated growth in Port Elgin, a new station, "Saugeen Shores DS", will be built in close proximity to the subdivision growth, which will prevent overloading of the existing F2 feeder and Port Elgin DS. By appropriately timing the construction of Saugeen Shores DS, Hydro One will prevent overloading issues, thereby avoiding the failure of existing infrastructure. At the current rate of new home connections, Hydro One anticipates that the remaining available capacity will be exhausted by 2022, and is planning to pace the investments accordingly to address system capacity needs.

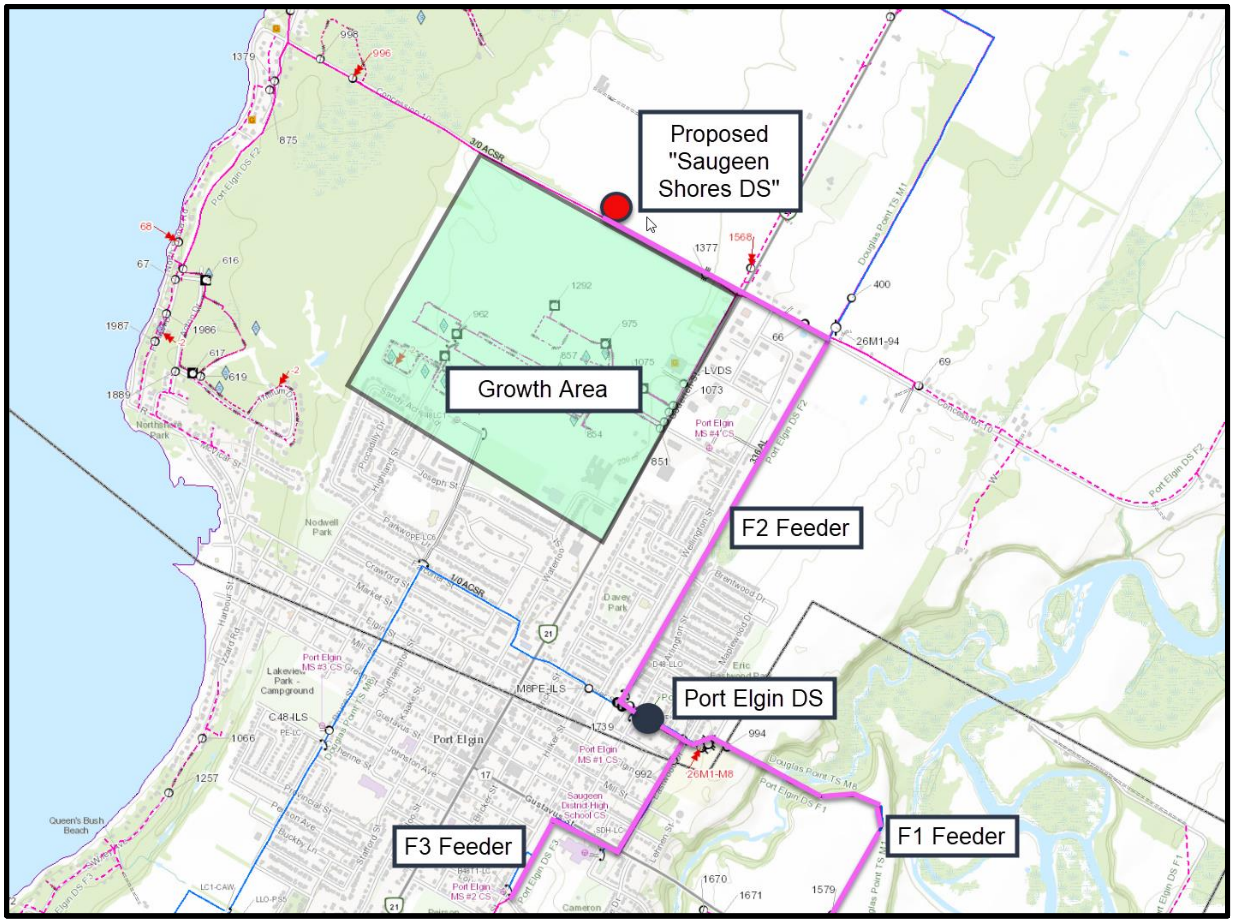

Figure 3: Port Elgin DS Electrical Configuration

B.1 INVESTMENT DESCRIPTION – LEAMINGTON

OVERVIEW

Within the province of Ontario, the Municipality of Leamington is experiencing unprecedented growth, where the impact of modern farming has dramatically changed the landscape for Hydro One as an electrical distributor. Leamington is home to an established – and growing – greenhouse sector, where the agricultural benefits include year-round crops, climate control, and increased yield. As greenhouse farming requires energy to realize these benefits, an adequate electrical supply is required to support the growth of this industry.

The investments specific to Leamington within this ISD encompass feeder development projects resulting from Regional Planning, and account for approximately one third of all D-SS-01 investments. The electrical demands of the Leamington-area greenhouses are substantial, and are driven by energy intensive grow lights that greenhouses rely upon. As mentioned in the associated transmission investment summary document, T-SA-10, Hydro One Transmission is obligated under its license to accommodate loading connections and increases when requested by customers. The distribution investments must be coordinated with Hydro One Transmission to align capacity increases, ensuring the additional transmission capacity can be used at the distribution level as soon as it is available. To facilitate the transmission work, Hydro One Distribution will also make a capital contribution to Hydro One Transmission, the details of which are found in the investment summary document, GSP Section 4.11, G-GP-22.

GROWTH FORECASTS

Capacity limitations within the Leamington area are especially pronounced as a result of the growth in the greenhouse sector. Customer requests for additional capacity have totaled approximately 1400MW as of year-end 2020. Since the growth is diversified amongst many customers, the impact of a single customer load failing to meet their forecasted load is minimal. As a result, the established growth trend amongst all customers within this segment is expected to be maintained, as demonstrated by loading increases that have already materialized. In order to meet this demand growth the construction of transmission facilities (DESN's) and the construction of distribution facilities, such as new overhead or underground lines, are required. The distribution investments within this ISD are anticipated to meet the continued growth in Leamington, and provide distribution customers with access to additional capacity as it becomes available.

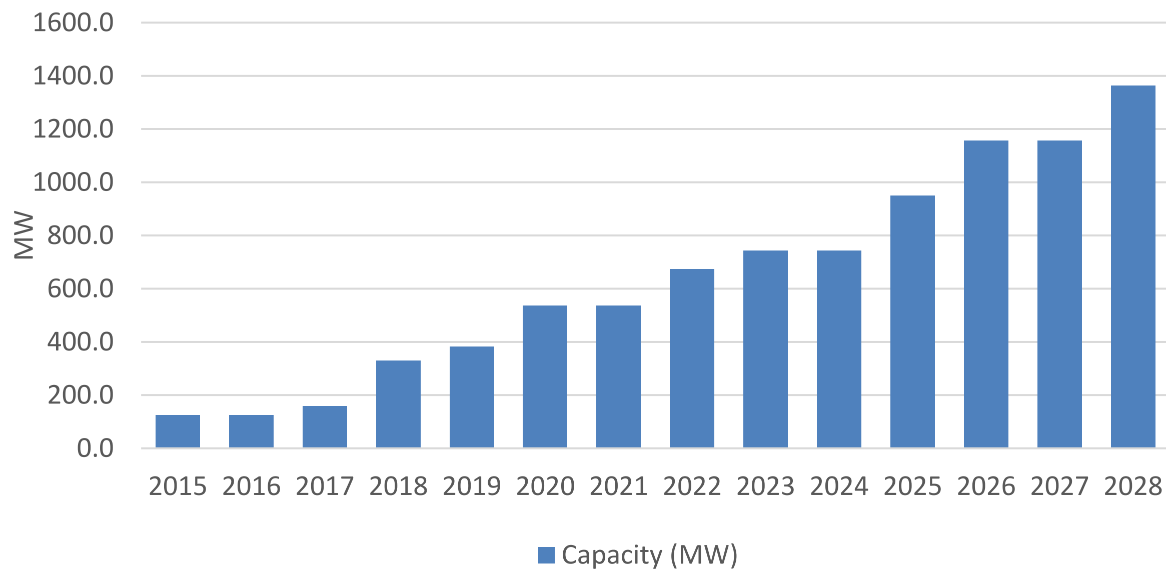

Figure 4: Kingsville-Leamington Capacity (MW)

The investment details outlined below summarize the significant efforts Hydro One is undertaking to meet the unprecedented customer demand. In addition to meeting capacity needs through the construction of new assets, Hydro One may also address capacity by reassessing the needs of individual customers. For example, as new customers connect and develop their greenhouses, if their requested capacity exceeds their actual needs, capacity may be reassigned to other customers to maximize capacity utilization.

INVESTMENTS

The distribution investments within D-SS-01 that are associated with the Leamington area are focused on the feeder work required to bring additional capacity to customers within the distribution system. Hydro One has already completed the construction of two 75/125MVA DESNs[2] in the Leamington area in response to capacity needs. A timeline of the completed and in-progress developments are as follows:

[2]A DESN consists of two (2) transformers.

1. "Leamington TS DESN1" was completed by Hydro One Transmission in December of 2017 Hydro One Distribution's scope was completed over 2018-2019, including the construction of 50 circuit-km of overhead lines as well as the reconfiguration of feeder ties to balance loading with Kingsville TS.
2. "Leamington TS DESN2" was completed by Hydro One Transmission in 2019. Hydro One Distribution's scope was completed over 2019-2020, including the construction of 30 circuit-km of overhead lines, 26 circuit-km of underground lines, and a further reconfiguration of feeders and ties to balance circuit loading. The significant construction of underground circuits within Leamington is a result of insufficient space on road allowance. In order to construct an adequate number of distribution circuits to utilize the available transmission capacity within the distribution system, underground circuits have been – and must continue to be – utilized as part of the design. Although underground circuits are not susceptible to the same number of reliability issues as overhead circuits, their construction comes at an incremental cost. In Figure 5 below, a picture of the overhead circuits just outside of Leamington TS #1 is shown, demonstrating the congestion resulting from the number of circuits required to be built out of this station. Since additional circuits were required to access the capacity at Leamington TS #2, Hydro One was obliged to pursue underground design options in the absence of feasible overhead options. As a result, Hydro One constructed these additional underground circuits within a nearby off road easement.

Figure 5: Leamington TS #1 Overhead Circuit Congestion

3. "South Middle Road DESN 1": Hydro One Transmission is planning to in-service this DESN by 2022. Hydro One Distribution's associated circuits to utilize the capacity of this DESN will include the construction of 100 circuit-km of overhead lines and 50 circuit-km of underground lines as well as the associated reconfiguration of feeders and ties to balance circuit loading, similar to the previous phases of development. This distribution scope of work will be in-serviced between 2022-2023.

Further to the investments listed above, Hydro One Transmission has plans to build three additional DESNs (and associated Distribution feeders) over the 2023-2027 period:

1. South Middle Road DESN2 (referred to as “Leamington Area Station #4” in TSP Section 2.11, T-SA-10) is estimated to be completed by Hydro One Transmission in 2025;
   - The associated distribution design work will begin in 2022, with construction expected to be completed in 2025.
   - 84 circuit-km of overhead feeders, 50 circuit-km of underground feeders, and a reconfiguration of the existing ties and circuits to balance feeder loading between all area DESNs.
2. “Leamington Area Station #5” is estimated to be completed by Hydro One Transmission in 2026;
   - The associated distribution design work will begin in 2023.
   - Hydro One Distribution’s plans call for the construction of 50 circuit-km of overhead lines as well as the reconfiguration of feeder ties to balance loading with existing stations and lines in the area. Once Hydro One Transmission confirms the precise location of the station, Hydro One Distribution’s scope will be finalized.
3. “Leamington Area Station #6 ” is estimated to be completed by Hydro One Transmission in 2028
   - The associated Distribution design work will begin in 2025 .
   - Hydro One Distribution’s plans call for the construction of 50 circuit-km of overhead lines as well as the reconfiguration of feeder ties to balance loading with existing stations and lines in the area. Once Hydro One Transmission confirms the precise location of the station, Hydro One Distribution’s scope will be finalized.

Figure 6 below provides an overview of the distribution scope for the above referenced projects in the Leamington area.

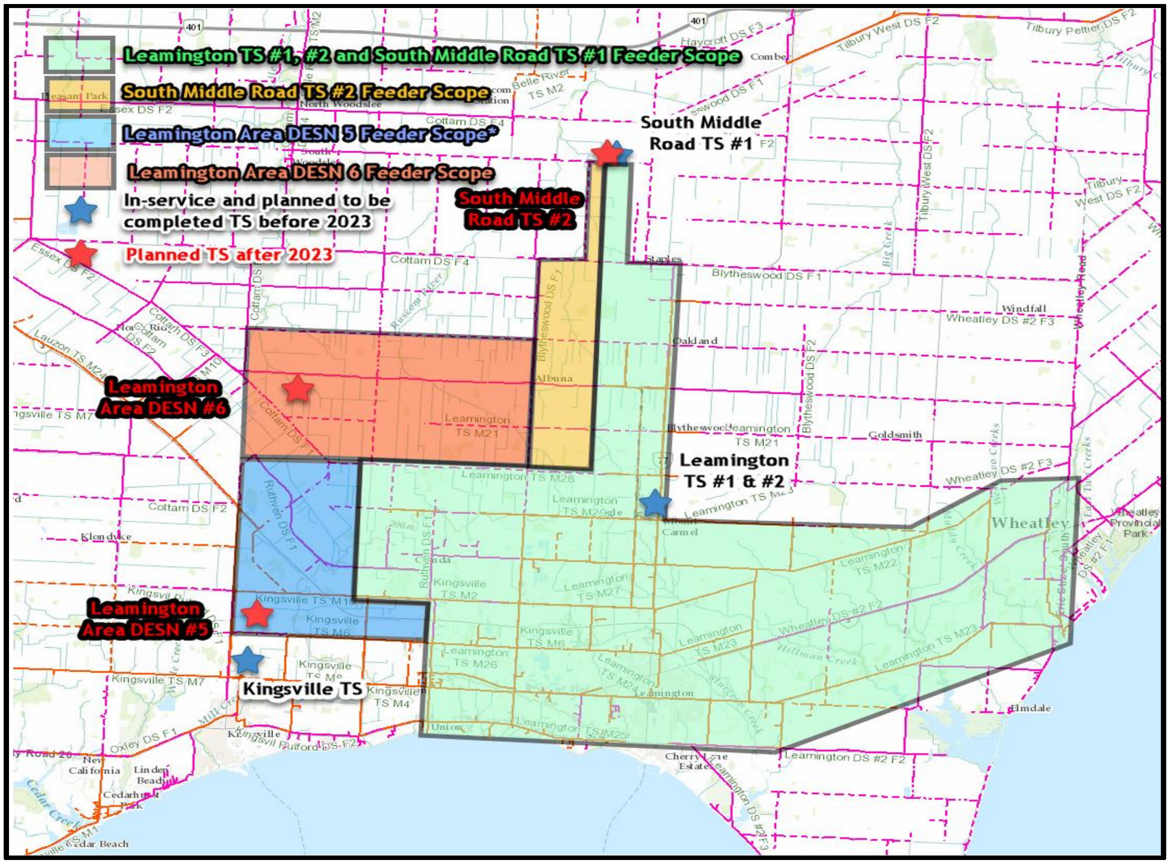

Figure 6: Distribution Projects in Leamington Area

C. OUTCOMES

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;
- Reducing the risk of lengthy customer outages caused by failure of overloaded assets; and
- Manage feeder loading to allow for additional customer connections and to improve voltage and power quality.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 1 - Outcome Summary

Customer Focus	• Meet capacity needs of existing and new customers. • Ensure acceptable delivery voltage is provided to customers.
Operational Effectiveness	• Maintain the safe and effective operation of the distribution system by avoiding the overload of distribution assets, and adhering to standards of voltage delivery.
Public Policy Responsiveness	• Meet requirements of Section 3.3 Enhancements of the DSC to plan the system to accommodate reasonable forecast load growth.

D. EXPENDITURE PLAN

Hydro One performs system studies to develop investments that address the identified load growth needs. The cost for the proposed investments are based on historical costs for similar projects.

Table 2 below summarizes the projected spending on the aggregate investment level. Since this ISD is comprised of unique investments, with different planned execution timelines, the associated investments totals listed within Table 2 have corresponding yearly variations. The detailed breakdown of each investment can be found in Appendix A.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	107.5	82.6	137.9	84.5	111.5	523.9
Less Removals	9.3	6.3	10.4	8.4	11.3	45.7
Capital and Minor Fixed Assets	**98.2**	**76.3**	**127.5**	**76.1**	**100.2**	**478.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**98.2**	**76.3**	**127.5**	**76.1**	**100.2**	**478.2**

The factors influencing the cost of the investment include:

- The factors influencing the cost of Load Growth Investments are dictated by the capability of Hydro One's existing assets to support localized growth, as well as the complexity of the work to resolve identified issues.
- The volume and scope of load growth projects has increased for this rate filing over the previous filing, which has driven a corresponding increase in required capital expenditures
- Due to the congestion of distribution feeders in the Leamington area, some of the proposed feeders are expected to have complex design requirements, or will require underground construction. As a result, there are increased costs per km in the Leamington area beyond what would have been forecast if only overhead circuits were used.
- The final location of Transmission Stations in the Leamington area have a direct correlation to the length of distribution circuits required.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: DO NOTHING

Allow load growth to continue until the increased loading results in either asset failure or power quality issues, compelling Hydro One to respond to the issue on an emergency basis. 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.

ALTERNATIVE 2: SYSTEM UPGRADES TO MEET LOAD GROWTH (RECOMMENDED)

Proactively monitor system loading, conduct planned studies and system impact assessments for large 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.

F. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the investment include the acquisition of real estate rights, and construction limitations related to seasonality. The construction of new stations requires acquisition of new property and is subject to delays due to the lack of a willing seller or negotiations with property owners, or municipalities. In some cases, road authorities may have coinciding plans for road widening or other construction, which need to be coordinated with new pole locations potentially resulting in delays to line construction work. 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.

APPENDIX A – DESCRIPTION OF INVESTMENTS

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2023	2024	2025	2026	2027
City of Owen Sound Tie-Line Reinforcement	SS-01.1	Construct 1.0km of new 4.16kV tie-lines and install new tie switches between 24th St West DS and 2nd Ave West DS, and between 6th Street East DS, and 2nd Ave East DS to improve load transfer capability between these stations due to load growth.	0.0	0.3	2.3	0.0	0.0
Bradford North DS	SS-01.2	Construction of a new 44kV:27.6kV DS, as well as associated feeders, to support area growth and relieve existing 27.6kV feeders.	0.0	0.4	4.5	0.0	0.0
Colpoys Bay DS F2 Feeder Upgrade	SS-01.3	Upgrade 4.5km of 12.5kV line on Colpoys Bay DS F2 feeder from 1phase to 3phase.	0.1	1.1	0.0	0.0	0.0
Lively DS F2 Upgrade - Black Lake Rd	SS-01.4	Upgrade 2.5km of 12.47kV line from Lively DS F2 feeder from 1-phase to 3-phase.	0.0	0.0	0.1	1.4	0.1
Mar DS	SS-01.5	Construction of new 44kV:8.32kV Mar DS to relieve loading on Colpoys Bay DS and facilitate residential and summer tourism load growth	0.0	0.6	4.3	0.0	0.0
Town of Shelburne voltage conversion	SS-01.6	Construction of a new 44kV:8.32kV DS to replace Shelburne DS, and increase station capacity, to support load growth in the area	2.9	0.0	0.0	0.0	0.0
New Old School DS and feeders	SS-01.7	Construction of a new 44kV:27.6kV DS, and 4 new 27.6kV feeders, to relieve existing 27.6kV feeders out of Snelgrove DS and to accommodate future load growth	1.9	0.0	0.0	0.0	0.0
King City DS - New Station & Feeders	SS-01.8	Construction of a new 44kV:13.8kV DS. Build feeder ties and transfer load with existing 13.8kV feeders from Eversley DS, to balance load between feeders / stations.	0.0	0.0	0.0	0.5	2.9
Caledonia TS New Feeders	SS-01.9	Construction of 20 circuit-km of 27.6kV feeder to relieve capacity constraints on Caledonia TS M5 feeder, and supply existing and new load from Caledonia TS M6 feeder.	1.1	5.3	0.0	0.0	0.0
Brockville 44kV Load Growth	SS-01.10	Construction of Phase 1 of a new overbuild double circuit 44kV line out of Brockville TS toward the Prescott area, to provide load relief and facilitate future load growth. 7km out of the total 18.5km.	8.6	0.0	0.0	0.0	0.0
Dresden Area Load Relief	SS-01.11	Build 17km of double circuit 27.6kV feeder from Wallaceburg TS to intersection of Cedar Line and Kent Bridge Rd, to accommodate for load growth in the area.	0.1	1.3	5.0	4.7	0.0

Ancaster Area Load Relief	SS-01.12	Construction of 25 circuit-km of 27.6kV line to relieve capacity constraints on Dundas TS M4, M6, and Nebo TS M6, M7, M8 feeders. Existing and forecast load transferred to Dundas TS #2 M15 and M16 feeders.	0.0	0.0	0.0	1.8	6.1
Dover Center Load Relief	SS-01.13	Extend Wallaceburg TS M3 by overbuilding 13.3km of 27.6kV feeder along Dover Center DS F2 to accommodate future load growth.	0.0	0.9	4.6	0.0	0.0
Hawthorne TS M1 Load Growth	SS-01.14	Installation of a new 115kV:27.6kV 15MVA transformer in the existing Manotick DS yard, and construction of two new 27.6kV feeders to support load growth in the area.	0.8	4.1	0.0	0.0	0.0
Almonte TS M28 Load Growth	SS-01.15	Construction of 2km of 44kV line from Townline Rd East to relieve Almonte TS M26 feeder	0.0	0.0	0.3	3.1	0.0
Elginburg DS F2 and Station Load Growth	SS-01.16	Transfer sections of Elginburg DS F2 to Cataraqui DS F2, and install line voltage regulator to support load transfer.	1.4	0.0	0.0	0.0	0.0
Harrowsmith DS F3 F5 Load Growth	SS-01.17	Construction of 8km of new 12.5kV feeder to offload both F3 and F5, and redistribute loads	0.0	2.5	1.2	0.0	0.0
Pembroke TS Load Growth	SS-01.18	Construction of 8km of new 44kV feeder up to Greenwood DS to relieve Pembroke TS M2 feeder	0.0	0.0	0.0	1.0	9.5
Calabogie DS F1 Load Growth	SS-01.19	Construction of a new 7km 12.5kV feeder out of Calabogie DS to Barret Chute Road to relieve loading on F1 feeder	0.0	0.1	2.2	0.0	0.0
Manotick DS Add F3 Feeder Load Growth	SS-01.20	Construction of a new 8.32kV feeder out of Manotick DS to relieve loading on F1 and F2 feeder	2.4	0.0	0.0	0.0	0.0
Stewartville TS Load Growth	SS-01.21	Construction of 2km of 44kV overbuild line to transfer load from Stewartville TS to Arnprior TS	0.0	0.0	0.0	0.1	1.2
Kemptville 8kV Load Growth	SS-01.22	Construction of a new 44kV:8.32kV padmount DS to relieve loading on Kemptville West and Acton Corners DS	1.6	0.0	0.0	0.0	0.0
Chesterville TS Load Growth	SS-01.23	Construction of a new 27.6kV:8.32kV padmount DS to offload Chesterville TS M4 via Newington DS F2. Install new switches to offload Chesterville M2 onto Morrisburg M26.	0.0	0.0	0.1	1.1	0.0
Listowel Load Relief - Load Growth	SS-01.24	Construction of 3 km of double circuit 44kV line and install a 44kV:4.16kV pad mount transformer to relieve Listowel Elma, Bright and Davidson DS's.	1.5	0.0	0.0	0.0	0.0
Ferndale DS F2 Feeder Upgrade - Load Growth	SS-01.25	Upgrade 8.4km of 12.5kV line on Ferndale DS F2 from 1phase to 3phase.	0.1	2.3	0.0	0.0	0.0

Saugeen Shores DS and Port Elgin Load Growth	SS-01.26	Construction of a new 44kV:8.32kV Saugeen Shores DS to relieve loading on Port Elgin DS and facilitate residential and commercial subdivision growth	2.8	1.8	0.0	0.0	0.0
Commanda DS Load Growth	SS-01.27	Construction of a new 44kV:12.47kV Commanda PDS to relieve loading on Commanda DS and facilitate load growth.	1.2	0.0	0.0	0.0	0.0
Kirkland Lake Voltage Conversion - Stage 2	SS-01.28	Voltage convert all feeders at Woods DS from 4.16kV to 12.47kV to relieve Woods DS F5, F6, F7.	2.4	0.0	0.0	0.0	0.0
Kirkland Lake Voltage Conversion - Part 3	SS-01.29	Voltage convert all feeders at Kirland Lake DS #1 from 4.16kV to 12.47kV to relieve Kirland Lake DS #1 F1, F2, F3.	2.9	0.0	0.0	0.0	0.0
Manitoulin TS - Add Third Feeder - Load Growth	SS-01.30	Construction of 1.5km of 44kV line from Manitoulin TS to relieve Manitoulin TS M26 feeder	0.0	0.2	5.1	0.0	0.0
Wikwemikong Supply - Station & Line Work	SS-01.31	Construction of 15km of 12.47kV line from Manitowaning DS to relieve Manitowaning DS F1 feeder	2.1	0.0	0.0	0.0	0.0
Crilly DS Upgrade	SS-01.32	Construction of a new 115kV:25kV Crilly DS to relieve loading on the existing Crilly DS and facilitate First Nation load growth	0.0	0.1	0.2	7.5	0.0
Elmhurst Beach DS	SS-01.33	Construction of a new 44kV:27.6kV DS to relieve loading on Elmhurst Beach DS and facilitate subdivision growth.	0.0	0.0	5.4	0.0	0.0
Kleinburg TS M26 Extension	SS-01.34	Construction of 11km of 44kV line to the Mayfield West region, to relieve Pleasant TS M21 and support future load growth in the area	0.0	0.0	0.0	0.2	2.2
Mount Albert DS	SS-01.35	Construction of a new 44:8.32kV DS to relieve loading on Mount Albert DS and facilitate subdivision growth.	0.2	1.6	0.0	0.0	0.0
Midhurst Wilson DS F2 Extend to Doran Rd Load Grow	SS-01.36	Overbuild 6.5km of existing 8.32kV line with a new 27.6kV feeder from Wilson Road to Doran Rd	2.4	0.0	0.0	0.0	0.0
Midhurst Wilson DS Feeder Development to Carson Rd	SS-01.37	Construction of 2km of 27.6kV line from Snow Valley DS to facilitate subdivision growth	0.0	1.0	0.0	0.0	0.0
Carlisle DS Offloading	SS-01.38	Construction of 5 circuit-km of 27.6kV feeder, and installation of 2 x 2.5MVA 27.6kV:8.32kV pad-mount transformers, to relieve capacity constraints on Carlisle DS	0.0	2.4	0.8	0.0	0.0
Solina DS Upgrade and Feeder Expansion	SS-01.39	Installation of a second 44kV:27.6kV 10MVA transformer in the existing Solina DS yard, and construction of 2 new 27.6kV feeders to support load growth in the area.	0.0	0.5	4.6	0.0	0.0

Bondhead Area Load Relief	SS-01.40	Construction of 9km of 44kV line from Kleinburg TS M24 to relieve Holland TS M4, to support load growth in the Bondhead Area along Highway 400	0.0	0.2	4.5	0.0	0.0
South Middle Road TS DESN1 Feeder Development	SS-01.41	Build 12 new 27.6kV feeders from South Middle Road TS DESN1 (approximately 100 circuit-km of overhead circuits and 50 circuit-km of underground circuits), and reconfigure the existing system to balance loading while supporting load growth.	14.2	1.2	0.8	0.0	0.0
Norfolk TS new feeder build	SS-01.42	Build 25 circuit-km of 27.6kV feeder to relieve capacity constraints on Norfolk TS M3, M5 and M6 feeders, and supply existing and new load from Jarvis TS M1 and M4 feeders.	0.0	0.0	0.0	0.5	8.0
Edgeware TS new feeder build	SS-01.43	Build 8 circuit-km of 27.6kV feeder to relieve capacity constraints on Edgeware TS M2 feeder, and supply existing and new load from Edgeware TS M3 feeder.	0.0	0.0	0.0	0.4	1.7
Bloomsburg HVDS new feeder build	SS-01.44	Build 15 circuit-km of 27.6kV feeder to relieve capacity constraints on Bloomsburg HVDS M1 and M2 feeders, and supply existing and new load from new Bloomsburg HVDS M4 and M5 feeders.	0.0	0.2	2.5	2.4	0.0
South Middle Road TS DESN2 Feeder Development	SS-01.45	Build 12 new 27.6kV feeders from South Middle Road TS DESN 2 (approximately 84 circuit-km of 27.6kV overhead circuits, and 50 circuit-km of 27.6kV underground circuits), and reconfigure the existing system to balance loading while supporting load growth.	13.9	15.8	39.5	0.0	0.0
Rockland West Load Growth	SS-01.46	Installation of a second 115kV:8.32kV 7.5MVA transformer in the existing Rockland DS yard, and construction of 3 new 8.32kV feeders to support load growth in the area.	0.1	1.0	1.7	0.0	0.0
Brockville 8kV Load Growth	SS-01.47	Installation of two 44kV:8.32kV pad mount transformers for the Brockville 8.32kV system to support load growth and provide back up in the area	2.7	0.0	0.0	0.0	0.0
Frontenac TS Load Growth	SS-01.48	Construction of 8km of 44kV overbuild line to transfer load from Frontenac TS to Gardiner TS	0.0	0.0	0.0	0.7	2.1
Napanee TS M3 Load Growth	SS-01.49	Construction of 7km of new 44kV line from Napanee TS M4 to relieve the overloaded Napanee TS M3 feeder	0.0	0.0	0.0	0.3	1.9
Curve Inn DS New Feeder	SS-01.50	Construction of a new 27.6kV feeder, and 7km of line, from Curve Inn DS to relieve Park Road DS F1 and supply future load growth in the area.	2.6	0.0	0.0	0.0	0.0

Belle River Load Growth	SS-01.51	Construction of a new feeder position and approximately 11 km of new distribution line to relieve existing feeders and bring additional capacity to the western part of Town of Lakeshore	0.0	0.0	0.6	2.5	2.5
Manning Road and Hwy 2 Load Growth	SS-01.52	Construction of approximately 12 km of new distribution line to relieve existing feeders and bring additional capacity to the western part of Town of Lakeshore	0.0	0.5	2.0	2.0	0.0
Holland DS F1 to Doane DS F2 Feeder Tie	SS-01.53	Construction of 7km of new 27.6kV line to transfer a portion of Doane DS F2 to Holland DS F1 to provide load relief and alleviate PQ issues.	0.0	0.5	1.6	0.0	0.0
Corbetton Area Load Growth	SS-01.54	Installation of 2x3MVA padmounted transformers to relieve Corbetton DS F3 and support subdivision growth in the town of Dundalk	0.0	0.0	0.0	0.2	1.5
Kleinburg TS M28 Expansion - Load Growth	SS-01.55	Construction of 10km of new 44kV line out of Kleinburg TS to support industrial load growth in the Bolton area	0.0	0.0	0.3	5.6	2.8
Tillsonburg TS M1 Load Relief	SS-01.56	Construction of 28km of new 27.6kV feeder from Commerce Way TS to relieve loading on Tillsonburg TS M1 Feeder.	0.0	0.0	0.3	3.5	7.7
Strathroy Carroll St. Loop	SS-01.57	Extend Strathroy TS M3 feeder by 5 km to create a tie with Longwood TS M24 feeder to meet forecasted load growth	1.4	0.0	0.0	0.0	0.0
Strathroy TS Load Relief	SS-01.58	Construction of 14km of new 27.6kV feeder out of Longwood TS to relive loading on Strathroy TS M1 Feeder.	0.0	0.0	0.2	1.7	0.6
Wolverton HVDS Feeder Load Relief	SS-01.59	Construction of 3.5km of new 27.6kV line, and a new feeder position at Wolverton HVDS. Existing feeders will be reconfigured to improve reliability and accommodate load growth	0.0	0.0	0.1	1.2	0.4
Meaford TS M2 Conductor Refurbishment Load Growth	SS-01.60	Upgrade 3.5km of 44kV line by increasing conductor ampacity, in order to supply residential subdivision load growth and maintain voltage performance.	0.0	0.0	0.0	0.1	1.4
Owen Sound TS M26 Conductor Refurb Load Growth	SS-01.61	Upgrade 6.0km of 44kV line by increasing conductor ampacity, in order to supply residential and industrial load growth, and to maintain voltage performance.	0.0	0.0	0.1	1.6	0.8
Meaford TS M2 Padmounts Lora Bay Oxmead DS F3	SS-01.62	Construction of new 44kV:8.32kV Padmount DS to relieve loading on Oxmead DS and facilitate subdivision growth	2.7	0.0	0.0	0.0	0.0
Palmerston TS – M2 Load relief - New feeder	SS-01.63	Construction of 8.5km of new 44kV line from Palmerston TS to relieve the M2 feeder	0.0	0.0	0.4	3.8	1.8

Plainfield DS F3 Enhancement	SS-01.64	Upgrade 8.5km of 8.32kV line on Plainfield DS F3 from 1phase to 3phase	1.6	0.0	0.0	0.0	0.0
Dartford DS F3 Enhancement	SS-01.65	Upgrade 6km of 8.32kV line on Dartford DS F3 from 1phase to 3phase	0.6	1.9	0.4	0.0	0.0
Jarvis TS New Feeder Build	SS-01.66	Extend Jarvis TS M8 3.3km in order to supply new customers, and to transfer a portion of Jarvis TS M1 to address feeder capacity concerns.	0.4	3.1	0.0	0.0	0.0
Shabaqua DS F1 upgrade	SS-01.67	Voltage convert 20 km of line from 12.5kV to 25kV to address power quality concerns resulting from load growth.	0.0	0.0	0.0	0.3	4.7
Sunnidale Corners DS Load Growth	SS-01.68	Upgrade 1.5km of 4.8kV (1-phase) line to 8.32kV (3-phase) on Sunnidale Corners DS F2 to support load growth.	0.0	0.0	0.0	0.0	2.0
Marionville DS Load Growth	SS-01.69	Installation of a second 115kV:27.6kV 15MVA transformer in the existing Marionville DS yard, and construction of 2 new 27.6kV feeders to support load growth in the area.	0.0	0.0	0.0	0.3	5.3
Kemptville East 8kV Load Growth	SS-01.70	Construction of two new 44kV:8.32kV padmount DS to relieve loading on South Gower DS	0.0	0.3	2.5	1.2	0.0
Brockville 44kV Load Growth Part 2	SS-01.71	Construction of Phase 2 of a new overbuild double circuit 44kV line out of Brockville TS toward the Prescott area, to provide load relief and facilitate future load growth. 11.5km out of the total 18.5km.	3.7	1.8	0.0	0.0	0.0
Newport PDS Load Relief	SS-01.72	Offload a portion of Newport PDS onto Jarvis TS M3 and Caledonia TS M6 feeders, through approximately 12kms of 8.32kV:27.6kV voltage conversion, and 5 x 16kV:4.8kV pole-top step transformers.	0.4	4.9	0.0	0.0	0.0
Lambton TS M7 M8 Feeder Build	SS-01.73	Build 16 circuit-km of 27.6kV feeder to relieve capacity constraints on Lambton TS M1, M3 and M5 feeders, and supply existing and new load using the new Lambton TS M7 and M8 feeder positions.	5.5	0.0	0.0	0.0	0.0
Burleigh DS F2 1ph to 3ph Coversion - Part 2	SS-01.74	Upgrade 5.4 km of 12.5 kV line go upgrade Burleigh DS F2 feeder from 1ph to 3ph	0.0	1.5	0.0	0.0	0.0
Leamington Area DESN5 Feeder Development	SS-01.75	Build 12 new 27.6kV feeders from Leamington Area DESN 5 (approximately 50 circuit-km of overhead circuits), and reconfigure the existing system to balance loading while supporting load growth.	0.9	11.7	23.8	12.2	0.0

Leamington Area DESN6 Feeder Development	SS-01.76	Build 12 new 27.6kV feeders from Leamington Area DESN 6 (approximately 50 circuit-km of overhead circuits), and reconfigure the existing system to balance loading while supporting load growth.	0.0	0.0	1.0	12.2	24.8
Forest Jura DS Fan Monitoring	SS-01.77	Install fan monitoring and SCADA telemetry at Forest Jura HVDS to provide additional capacity for future load growth.	0.1	1.3	0.0	0.0	0.0
Dunnville DS F1 Load Relief	SS-01.78	Offload portion of Dunnville DS F1 onto Dunnville TS M1 through 2.25km of 8.32kV: 27.6kV voltage conversion, and 6 x 16kV:4.8kV pole-top step transformers.	1.3	0.0	0.0	0.0	0.0
Other Projects (<$1M)			9.3	3.9	4.5	2.2	8.2
Total			**98.2**	**76.3**	**127.5**	**76.1**	**100.2**

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D-SS-02	RELIABILITY IMPROVEMENTS
Primary Trigger:	Reliability
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	7.3	0.1	6.5	18.6	7.5	40.0

Summary:

Hydro One's distribution system is typically planned based on a radial supply, as this is the most cost-effective means of distributing electricity to end-use customers. A radial design, however, does not have an alternate source of power in the event of an outage. This investment resolves reliability issues that are a result of a predominantly radial system design. The primary trigger of the investment is reliability. This investment is expected to improve reliability and increase operational flexibility through the creation of new feeder ties and the addition of SCADA to enable remote switching capabilities.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One's distribution system is typically planned based on a radial supply, as this is the most cost-effective means of distributing electricity to end-use customers. A radial design, however, does not have an alternate source of power in the event of an outage. As a result, where there is an outage on a radial feeder, workers will have to physically locate the fault, and remedy the cause of the outage before power can be restored to the customers on that feeder, or portion of the feeder.

Through the customer engagement survey, investing in reliability was identified as one of the most important customer priorities. Reliability improvement investments focus on building or upgrading feeder ties feeders where backfeed from an alternate feeder will meaningfully improve feeder performance.

Where the opportunity exists, and where sufficiently justified through reliability analyses, feeder ties and SCADA-enabled tie switches can be constructed between candidate feeders to establish a loop feed design. The addition of feeder ties will improve reliability in two ways, 1) through system resiliency, which minimizes the extent of an outage by backfeeding from an alternate source, and 2) through operator control and SCADA-enabled switching points, which improve response times as a result of the remote control capabilities. Traditional switching must be done on site, and takes time for responding crews to perform these functions.

B. INVESTMENT DESCRIPTION

This investment is focused on improving reliability through remote load transfer capability, resulting in reduced outage durations. Since each distribution feeder is unique, the optimal solution to enable load transfers depends on the existing load transfer limitations. The investments within this ISD overcome these limitations through one of two means:

1. Addition of feeder ties: To minimize the duration of an outage experienced, customers can be temporarily supplied from an alternate source as the faulted section of line is addressed.
2. Improved backfeed capabilities: In some cases feeder ties exist, but are limited in their ability to backfeed customers due to resulting voltage levels or loading limitations of equipment or protection devices. Improvements to address these issues could be increased conductor size or the addition of voltage regulators.

EXAMPLE INVESTMENT "MUSKOKA M1-M5 TIE"

The Muskoka M1 and M5 feeders both have significant radial line sections that supply multiple distribution stations. The line length for the M1 and M5 feeders is 102km, and 15km, respectively. This line length is an indication of exposure, meaning that by virtue of the length, there is more opportunity for vegetation contact, animal contact, and so on. In 2020, the Muskoka M1 and M5 feeders were among the feeders that contributed most to system SAIDI, indicating the need to make reliability improvements to both feeders.

The proposed reliability investment involves the extension of the M5 feeder, to establish a tie with the M1, and includes the addition of remote operable switches that will enable remote load transfers between these feeders under fault conditions. This reduces the overall exposure of the M1, without incurring additional risk for M5 performance as a result of the remote operable switches.

The Figures below illustrate the staged benefits that can be gained by the construction of feeder ties and the addition of remote operable switches. Note that in the accompanying pictures, de-energized lines are shown as red:

Stage A

The existing switching arrangement at Muskoka M1 and M5 is focused on sectionalization, with most Distribution Stations on these feeders radially fed. The existing switching helps minimize the extent of an outage, but is limited in its restoration capabilities. Figure 1 below shows the "normal" (unfaulted) conditions for the M1 and M5 feeders:

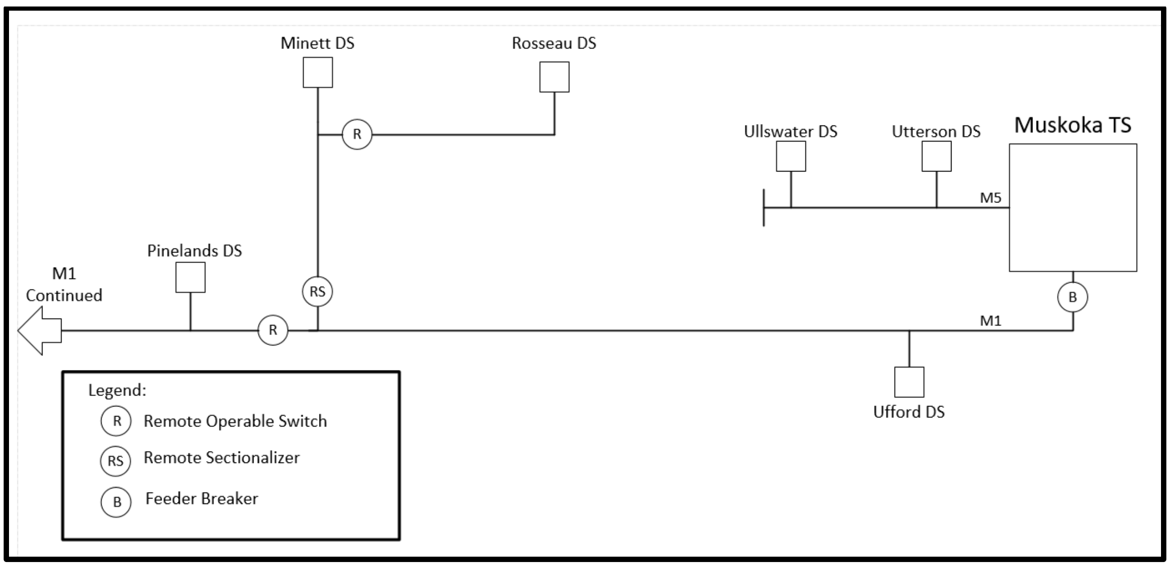

Figure 1: Stage A Existing "Unfaulted" Configuration

Stage B

Under the existing configuration, in the event a fault happens between Minett DS and Rosseau DS, the remote operable switches can be used to detect the general location of a fault, isolate the faulted section, and restore power to all unfaulted feeder sections. This example highlights two key benefits of remote operable switches; 1) Minett DS can have its power restored for faults towards Rosseau DS, reducing the extent of the outage, and 2) this restoration can happen in real-time through operator control, which reduces the outage duration for customers upstream of the faulted section. Further, fault location information that was broadcast from the remote operable switches to Hydro One's control centre through SCADA, is then relayed to responding crews to assist with restoration efforts. Stage B details are shown in Figure 2 below:

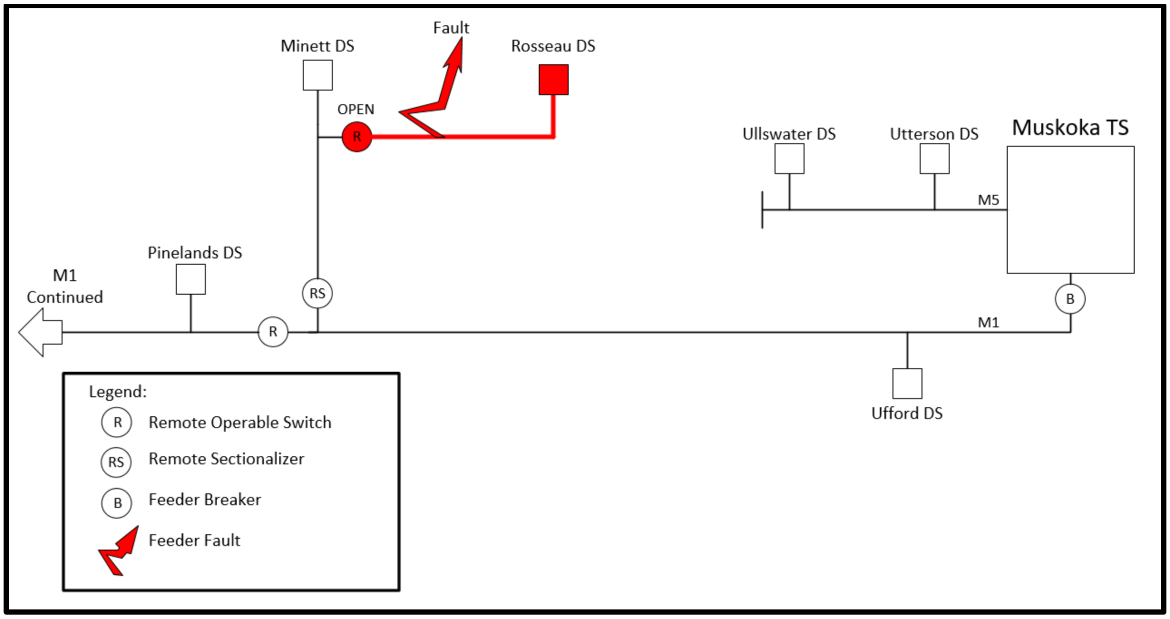

Figure 2: Stage B Existing "Faulted" Configuration

Stage C

Since both Minett DS and Rosseau DS are radially fed, with this example, Rousseau DS will remain without power until the cause of the fault is rectified and the remote operable switches are reclosed. By constructing a tie line and installing additional remote operable switches as an investment within D-SS-02, Hydro One will enable further reliability improvements on both the M1 and M5 feeders by providing an alternate source of supply and remote transfer capabilities. Figure 3 below shows the proposed tie-line construction with new assets shown in green, and the change in open point between the M1 and M5 feeders.

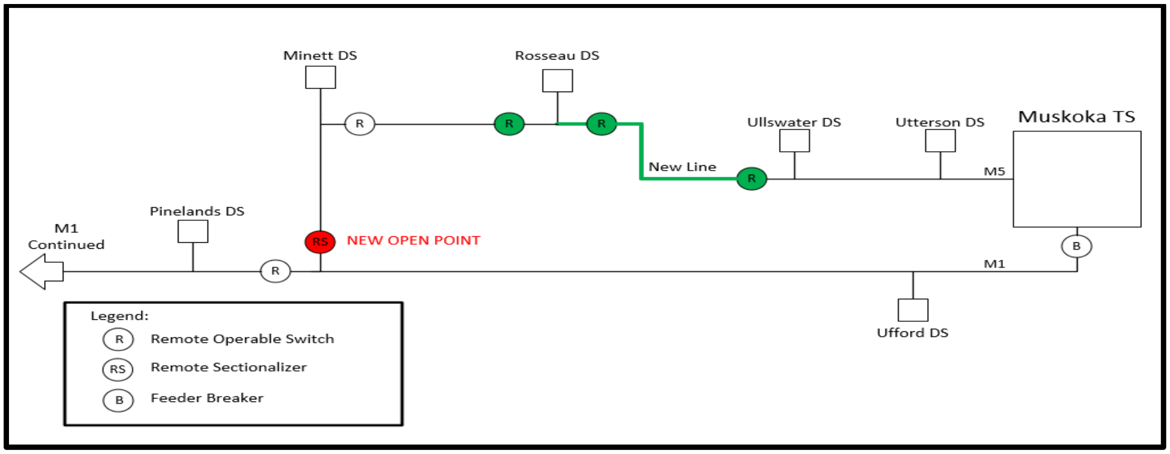

Figure 3: Proposed Feeder Tie and Switches

Stage D

Again, using a faulted section between Minett DS and Rosseau DS as an example, system operators are able to use fault information to determine the fault lies between these two stations. The switches upstream and downstream of the fault are remotely opened, and power restored to all feeder sections by closing the upstream switches and feeder breakers. In this example, both Minett DS and Rosseau DS can now have their power remotely restored, further reducing the extent of the outage, and maintaining distribution supply to all distribution stations (and consequently customers fed from those stations) on the M1 and M5 feeders.

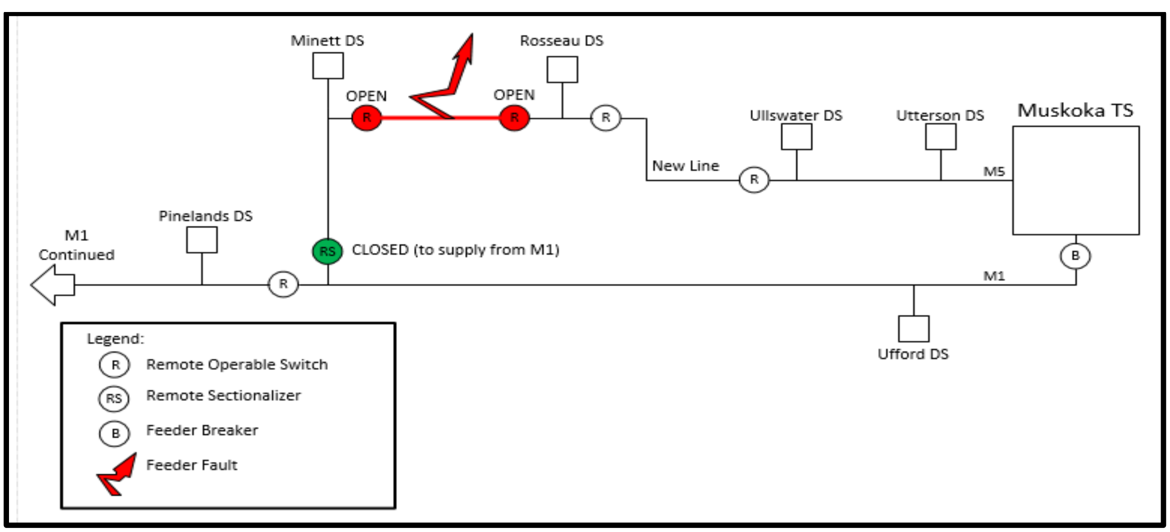

Figure 4: Proposed Feeder Tie and Switches "Faulted"

C. OUTCOMES

Reliability Improvement projects will:

- Improve operational efficiencies by remotely restoring power to as many customers as possible through feeder ties;
- Utilize fault location data to reduce the scope and duration of outages; and
- Invest in distribution improvements that align with customer priorities.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 1 - Outcome Summary

Customer Focus	• Undertake investments that align with customer priorities to invest in reliability
Operational Effectiveness	• Increased operational flexibility • Reduced outage duration and improved reliability

D. EXPENDITURE PLAN

Since this ISD is comprised of unique investments, with different planned execution timelines, the associated expenditure totals listed within Table 2, have corresponding yearly variations. A detailed breakdown of all expenditures that constitute this ISD can be found in Appendix A. below summarizes projected annual expenditures on the aggregate level. Since this ISD is comprised of unique investments, with different planned execution timelines, the associated expenditure totals listed within Table 2 have corresponding yearly variations. A detailed breakdown of all expenditures that constitute this ISD can be found in Appendix A.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	7.8	0.1	6.6	19.7	7.9	42.1
Less Removals	0.5	0.0	0.1	1.1	0.4	2.1
Capital and Minor Fixed Assets	**7.3**	**0.1**	**6.5**	**18.6**	**7.5**	**40.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**7.3**	**0.1**	**6.5**	**18.6**	**7.5**	**40.0**

The factors influencing the cost of the investment include:

- The extent of forestry work required for the new feeder section;
- The set-backs required by the road authority or property owner for the new feeder section;
- Structure replacements needed to accommodate the system upgrades needed for the new feeder tie, such as a larger conductor; and
- Unforeseen property/easement issues.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: DO NOTHING

Hydro One would not proceed with reliability investments to create feeder ties with remote switching capabilities. This alternative was rejected, as it does not proceed with cost effective reliability improvements.

ALTERNATIVE 2: TARGETED RELIABILITY IMPROVEMENTS (RECOMMENDED)

Implement targeted projects to improve reliability on feeders through the construction of feeder ties with remote switching capabilities. This alternative invests in cost-effective opportunities to improve customer reliability and operational flexibility.

F. EXECUTION RISK AND MITIGATION

The main risks concerning project execution are emergent issues identified during the detailed design stage, such as real estate, property rights, telecommunications limitations, etc. These risks are mitigated through extensive planning, scheduling, and outage coordination across lines of business and stakeholders.

1 **APPENDIX A – DESCRIPTION OF INVESTMENTS**

Project Name	Project ID	Project Description	Net Capital Investment ($M)				
			2023	**2024**	**2025**	**2026**	**2027**
Orillia TS M2-M6 New Tie Line	SS-02.1	Construct 7km of 44kV line and install 2 remote operable switches to enable sectionalizing and backfeed capabilities between Orillia TS M2 and M6.	3.1	0.0	0.0	0.0	0.0
Muskoka TS M1-M5 New Tie Line	SS-02.2	Construct 15km of 44kV line and install 3 remote operable switches to enable sectionalizing and backfeed capabilities between Muskoka TS M1 and M5.	0.0	0.0	0.2	10.3	0.0
Guthrie F1 x Medonte F2 44kV tie-line	SS-02.3	Construct 8km of 44kV line and install 3 remote operable switches to tie Midhurst TS - M4 and M9 circuits for backfeed capabilities	0.0	0.0	0.0	0.1	4.1
Muskoka TS M1 Reconductor	SS-02.4	Reconductor 11km of existing 3/0 ACSR on the Muskoka TS M1 feeder to 556AL to increase feeder loading limits and allow for improved backfeed capabilities	0.0	0.1	5.4	0.0	0.0
Curve Inn, Park Rd and Wilson TS M11 Tie Line	SS-02.5	Construct 3km of 44kV line and install 4 remote operable switches to tie Wilson TS M11 and M13 circuits for backfeed capabilities.	3.3	0.0	0.0	0.0	0.0
Palmerston TS M2-M4 Tie line	SS-02.6	Construct 12km of 44kV line and install 2 remote operable switches to tie Palmerston TS M2 and M4 circuits for backfeed capabilities	0.0	0.0	0.5	4.7	2.3
Kent TS M18-M23 Tie	SS-02.7	Construct 6km of 27.6kV line and install 3 remote operable switches to tie Kent TS M18 and M23 circuits for backfeed capabilities.	0.0	0.0	0.2	1.6	0.0
Other Projects (<$1M)			0.8	0.0	0.2	1.8	1.1
Total			**7.3**	**0.1**	**6.5**	**18.6**	**7.5**

D-SS-03	DEMAND SYSTEM MODIFICATIONS
Primary Trigger:	Capacity
OEB RRF Outcomes:	Customer Focus , Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	13.2	13.4	13.7	13.9	14.2	68.3

Summary:

This non-discretionary investment addresses near term system needs that arise as a result of localized growth on the distribution system, resulting in equipment overload or power quality issues. The primary trigger of this investment is capacity. Demand-driven system modifications are minor investments that enable localized load growth by promptly addressing capacity limitations.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Demand system modifications are non-discretionary investments that address near-term system needs that arise from naturally occurring changes to the distribution system, which are usually caused by localized load growth. Load growth can cause a variety of issues such as power quality violations, system inefficiencies, or overloading of protection equipment. Under section 3.3 (Enhancements) of the Distribution System Code, Hydro One is required to continue to plan and build its distribution system to mitigate such issues and accommodate reasonable forecast load growth.

B. INVESTMENT DESCRIPTION

Demand system modifications are minor investments driven by immediate or near-term needs. The execution of these investments may be:

1. Reactive in nature – investments typically in response to urgent issues such as power quality complaints.[1]
2. Proactive in nature – investments typically in response to customer connections, and are required to enable continued growth in localized areas.

Upon identification of an issue, Hydro One performs an evaluation to outline the feasible mitigating alternatives. Technical criteria such as voltage delivery standards are used to assess power quality issues, and equipment thermal limits are used to assess capacity issues.

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[1] Demand system modifications address changes or upgrades required to maintain the quality of supply to multiple customers, where supply issues affect a general area of the distribution system. By contrast, power quality investments in D-SS-06 encompass changes and upgrades that are narrow in scope, and are in response to a specific customer complaint with a focused corrective solution.

Investments that are performed as Demand System Modifications usually include system changes such as new or upgraded protection devices, new or upgraded voltage regulators or shunt capacitors, and system modifications such as feeder rebalancing.

C. OUTCOMES

This investment's primary outcome is to maintain reliability and power quality, which will in turn maintain customer satisfaction. This outcome will be achieved by addressing system needs such as equipment thermal limitations or by addressing delivery standard violations to align with the criteria in Hydro One's Conditions of Service (namely, CSA CAN-C235-83).

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Maintain customer satisfaction by responding to customer complaints and maintaining power quality.
Operational Effectiveness	• Maintain reliability and power quality by managing equipment thermal loading, feeder balance, and protection settings and coordination.
Public Policy Responsiveness	• Meet requirements of Section 3.3 Enhancements of the DSC to plan the system to accommodate reasonable forecast load growth.

D. EXPENDITURE PLAN

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	14.9	15.1	15.4	15.7	16.0	77.0
Less Removals	1.7	1.7	1.7	1.8	1.8	8.7
Capital and Minor Fixed Assets	**13.2**	**13.4**	**13.7**	**13.9**	**14.2**	**68.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**13.2**	**13.4**	**13.7**	**13.9**	**14.2**	**68.3**

The factors influencing the cost of Demand System Modifications are dictated by the capability of Hydro One's existing assets to support localized growth, as well as the complexity of the work to resolve identified issues. The forecast expenditures for this program are based on historical costs.

E. ALTERNATIVES

No alternatives are considered, since failure to respond to near term system needs that arise as a result of localized growth would violate the Distribution System Code and may result in unacceptable system performance.

F. EXECUTION RISK AND MITIGATION

No major risks are anticipated for this investment.

D-SS-04	ENERGY STORAGE SOLUTIONS
Primary Trigger:	Reliability
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	34.3	35.0	35.6	36.3	36.0	177.3

Summary:

This investment involves implementing battery energy storage solutions to improve reliability for customers who experience long interruption durations. The primary trigger of the investment is reliability. The investment is expected to improve reliability for vulnerable customers at locations where traditional reliability solutions are not economically viable or practical.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

From 2018 to 2020, Hydro One's customers experienced 15.8 hours of outages and 3.8 sustained interruptions per year on average, including all major weather events and loss of upstream transmission supply. However, Hydro One customers residing within First Nations communities experienced nearly 26 hours of outages and over 7 sustained interruptions per year on average. Furthermore, the ten First Nations communities experiencing the poorest reliability experienced 67.5 hours of outages and over 10 sustained interruptions per year[1]. First Nations customers living on-reserve have raised concerns as they face distinct challenges with respect to the lack of reliable power. For these communities, poor reliability is not merely an inconvenience – it brings serious community health and safety issues, as well as significant financial challenges.

Long and frequent power outages often result in loss of refrigerated and frozen food, representing months of protected hunting and harvested food upon which First Nations families depend for their livelihoods.[2] Many homes without wood stoves are left without heating and lighting in the cold winter months. The health and well-being of seniors and community members that are on temperature-sensitive medication and medical equipment powered by electricity are impacted by loss of power. School days are regularly interrupted by outages, limiting children's access to education. Based on an interview with Mattagami First Nation this year, the students lost around two weeks of education in 2020 due to power outages.[3] When there is a power outage, the shops and businesses are shut down, and community events have to be cancelled.[4] During an outbreak of a communicable disease, power outages place First

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[1] A-07-02 Appendix A Northern Communities Reliability Study.
[2] Anwaatin's Reliability Impact Evidence, Anwaatin Factum Motion to Review and Vary EB-2017-0335.
[3] "Power outages in Mattagami First Nation": https://northernontario.ctvnews.ca/video?clipId=1498988
[4] "Annual Wabun Youth Gathering takes place in Matachewan". Northernnews.ca/news/localnews/annual-wabun-youth-gathering-takes-place-in-matachewan

Nations residents' health in more serious jeopardy as public shelter gatherings pose a significant health risk.

Many rural Ontarians are also disproportionally impacted by poor reliability. In 2018 and 2019, around 35,000 rural residential customers experienced more than 50 hours of interruption each year, which is more than three times worse than the system average. During an outage, these customers are left without heating or air conditioning, lighting, hot water, and even running water. Moreover, power outages pose additional health and safety concerns for residents that rely on electric-powered medical equipment and temperature-sensitive medications.

Many of the First Nations communities and residential customers with poor reliability metrics are rural, with the path of electrical supply characterized by distribution feeders that are long, radial, and vulnerable to outages. Hydro One rural distribution feeders can be over 100 kilometres long, with numerous branches and significant off-road sections through heavily forested areas or submarine cables. These radial distribution feeders do not typically have an alternate source of supply and the cause of any outage must be corrected before power can be restored. Rural distribution feeders pose additional challenges for Hydro One staff responding to an outage, for example: rough or off-road terrain, lengthy line sections to patrol that result in increased travel time. These challenges result in prolonged outage durations.

Feeder sectionalization has traditionally been used to minimize the overall impact of an outage on the main trunk of the feeders. Unfortunately, for customers who reside at the furthest extents of a distribution feeder, sectionalization is unable to improve reliability performance or speed of restoration. By design, when feeder protection sectionalizes, it cuts power for all downstream customers in order to maintain continuity of supply to upstream customers. Therefore, these vulnerable customers who are at the tail end of the feeder will experience the outage until the cause of the outage can be identified and corrected.

The nature of the supply to these vulnerable customers limits the viable options available to improve reliability. Traditional measures to resolve reliability issues for these customers involve large capital investment that are not practical or economically feasible. A typical wires solution involves building tens of kilometers of new lines or more, which would be cost prohibitive. There is a need for a more cost-effective solution to improve reliability by mitigating the impact of all upstream outages regardless of the cause. This investment will provide vulnerable customers with a more reliable and stable supply of electricity to power their communities.

B. INVESTMENT DESCRIPTION

In recent years, increasing needs for system flexibility and reliability, combined with rapid decreases in the costs of battery technology, have enabled battery energy storage systems to play an increasing role in power systems across the world. Battery storage is a Distributed Energy Resource (DER) that can be used as a temporary source of energy during a system outage. Battery storage can be designed to pick up load on a feeder section when there is an interruption to the upstream power supply.

Hydro One Customer Engagement[5] results indicated a strong preference among all customer types for implementing battery energy storage solutions to provide reliability improvements for 4100 customers experiencing poor reliability over the plan period. Furthermore, there was strong support to improve reliability among First Nations communities, and many communities welcomed the idea of non-traditional solutions such as investments in battery storage.

Battery storage can be scaled to fit the reliability needs to a specific area, with solutions varying from the installation of residential storage batteries in a residential customer's home, to grid-scale battery energy storage systems that can back up a whole community.

Station battery storage backup will focus on larger pockets of customers or whole communities that are fed from long radial supply points and experience poor reliability. A particular focus will be on First Nations communities and other clusters of vulnerable customers that are

[5] SPF Section 1.6, Attachment 1

experiencing long and frequent outages. In cases where traditional solutions are unable to sufficiently improve reliability in a cost effective manner, battery storage is considered as a viable option to reduce supply interruption and improve reliability. Hydro One proposes to target 24 communities over the plan period. Please refer to Section 4.3 in the Northern Communities Reliability Study[6] for a list of candidate communities. To determine the optimum battery size needed for each community, two sizing criteria are used. The first criterion, peak battery demand (kW), takes into account the estimated peak demand of the community. The peak demand is based on historical community load. The second criterion, total battery energy (kWh), takes into account the average energy lost during an outage. Total battery energy is estimated based on average outage duration and average energy needs of the community.

AROLAND BESS PILOT PROJECT

Hydro One is implementing a pilot battery energy storage project with Aroland First Nation, a community of approximately 135 residents located around 350 km northeast of Thunder Bay. Between 2013 and 2017, Aroland averaged 11 outages and 57 hours of power interruptions per year. The community is served through 150 km of transmission circuit, 65 km of sub-transmission line and 15 km of distribution line. Any interruption to the upstream supply would result in a power outage for the First Nations community. The cost of a traditional solution to improve reliability to the customers by building an alternate supply is estimated to be on the order of $100M. Moreover, the reliability improvement is based on uncontrollable factors as the new supply would also traverse through rough terrain and heavily forested areas.

The installation of a centralized battery energy storage system just outside the community will allow the community to be supplied by the battery system during an upstream supply interruption. The total cost of Aroland BESS pilot project is approximately $10M. Compared to traditional alternatives, this is a cost-effective solution that is anticipated to improve the reliability of the community by approximately 60%.

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[6] A-07-02, Attachment 1

Figure 1: Aroland Battery Energy Storage System

Residential household battery backup will focus on individual customers who have experienced an average of more than 50 hours of outage per year. Hydro One proposes to install residential battery storage at around 2100 homes across the province over the plan period.

RESIDENTIAL RELIABILITY IMPROVEMENT PILOT PROJECT

Hydro One is currently undertaking a pilot project to improve the reliability for around 100 rural residential customers through residential household battery backup. As part of the pilot, Hydro One has conducted customer outreach to identify customers who meet the requirements and are willing to participate in the program. In order to qualify for the pilot, customers must be non-seasonal, non-electrically heated, billed at the residential rate class and live in single dwellings. These requirements ensure the battery system is not sitting idle for certain seasons of the year and will be operating within its rated power limits. Furthermore, there are additional technical requirements that must be met, such as acceptable internet signal and available wall space in a temperature-controlled room for the batteries. The customer selection criteria and process for the wider rollout of the program will be refined based on learnings from the pilot. Residential household battery backup is anticipated to reduce both outage duration and outage frequency by around 60%.

For many First Nations communities and rural residential customers, battery energy storage can be the most cost effective method to improve reliability, when other traditional alternatives prove inadequate or are not economically viable. Having improved reliability not only improves the quality of life, but also helps bring more opportunities for future economic growth for these remote areas and vulnerable customers.

C. OUTCOMES

Reliability improvement projects using battery energy storage systems will:

- Reduce the impact of outages, and respond to concerns raised by customers and communities; and
- Reduce outage durations and frequency for customers experiencing worse-than-average reliability.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Respond to customers' preferences to provide a more reliable power supply for customers experiencing extremely poor reliability by reducing the duration and number of outages for these customers.
Operational Effectiveness	• Improve reliability for customers experiencing long and frequent outages by temporarily supplying these customers from battery energy storage systems when the normal supply source is lost.

D. EXPENDITURE PLAN

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($M)		2023	2024	2025	2026	2027	Total
Gross Investment Cost	Grid Scale Storage	22.2	22.6	23.0	23.5	24.0	115.3
	Residential Storage	12.1	12.4	12.6	12.8	12.0	61.9
Less Removals		0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets		**34.3**	**35.0**	**35.6**	**36.3**	**36.0**	**177.3**
Less Capital Contributions		0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost		**34.3**	**35.0**	**35.6**	**36.3**	**36.0**	**177.3**

The factors influencing the cost of the investment include, but are not limited to the following:

Grid-scale storage:

- Cost of the batteries based on kW and kWh requirements
- Network connectivity availability
- Remote location of the community
- Real estate required for the battery energy storage system
- Results of required studies such as ground resistivity soil study, geo-technical study, topographical study, archaeological study, etc.

Residential storage:

- Cost of the batteries and number of batteries required
- Customer’s electrical panel location and physical layout
- Remote location of the home

The batteries have a guaranteed operating life of 10 years, at the end of which the batteries will have at least 80% of the original capacity. Hydro One has taken battery degradation into consideration when sizing the batteries for both grid-scale and residential storage deployment. Based on the battery cycle count and actual operating conditions, Hydro One expects the batteries to have a useful life of 15 to 20 years.

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended alternative.

ALTERNATIVE 1: DO NOTHING

The existing levels of poor reliability for vulnerable customers will remain. These customers will continue experiencing long and frequent interruptions, which will continue to have adverse impacts on the customers' quality of life, as described in the "Investment Need" section above. This alternative is rejected as it does not cost effectively improve reliability for vulnerable customers and is contrary to the preference of Hydro One's customers.

ALTERNATIVE 2: TRADITIONAL POLES AND WIRES SOLUTION

The nature of the supply to these vulnerable customers limits the viable options available to improve reliability. Traditional measures to resolve reliability issues for these customers involve large capital investment that are not practical or economically feasible. This alternative is rejected as it is not a cost effective or practical alternative to improve reliability for vulnerable customers.

ALTERNATIVE 3: ENERGY STORAGE SOLUTION – DRAFT PLAN PACE (RECOMMENDED)

Energy storage solutions contemplated in this program are considered for customers located in rural areas where the network topology does not allow for feasible or economical traditional solutions. At these locations, energy storage can be a more economical solution that is forecasted to improve reliability for target customers by around 60%, based on pilot projections. Based on the proposed plan, 4100 customers currently experiencing extremely poor reliability will benefit from this investment and this was strongly supported across all customer types as part of the Customer Engagement results. This alternative is selected as it cost effectively improves reliability for vulnerable customers and is in alignment with the preference of Hydro One's customers.

ALTERNATIVE 4: ENERGY STORAGE SOLUTION – ACCELERATED PACE

Under the accelerated pace, 8500 customers currently experiencing extremely poor reliability will benefit from this investment. Customer Engagement results suggest that there is less support for an accelerated pace compared to the proposed plan, therefore this alternative is rejected.

F. EXECUTION RISK AND MITIGATION

The main risks concerning project execution for grid-scale battery storage include:

- Procurement and Logistics Risks: Battery availability due to worldwide demand. These risks are mitigated by working together with the vendor in the early stage of the project.
- Real Estate Risks: Construction of grid-scale storage sites requires acquisition of new property and is subject to delays due to the lack of a willing seller or negotiations with property owners. These risks are mitigated by providing appropriate lead times to allow sufficient time for obtaining necessary property rights.
- Telecommunications Risks: Cellular strength at the battery storage sites may not be sufficient to monitor battery system performance. This risk is mitigated by verifying signal strength is suitable before selecting the battery system, or by utilizing satellite for communication at these sites.

D-SS-05	WORST PERFORMING FEEDERS
Primary Trigger:	Reliability
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	39.6	40.9	42.2	43.0	43.8	209.4

Summary:

This investment targets improving reliability of the 500 Worst Performing Feeders that cumulatively contribute to more than a quarter of Hydro One's SAIDI. The primary trigger of the investment is improving system reliability by reducing the duration and extent of interruptions. This investment is expected to reduce outage duration for over 600,000 customers.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

Hydro One customers on average have experienced about 15 hours of outage annually from 2011 to 2020, including all major weather events and loss of upstream transmission supply. Long duration of outages impact customer's negatively interrupting the regular flow of life, prevents business from providing normal service to their customers, and result in manufacturing delays and potential product loss. Through Phase 2 of the Customer Engagement, Hydro One received strong support among all customer groups to improve reliability through grid modernization. Leveraging reliability data, an annually updated list of "worst performing feeders" (WPF) is developed. This list ranks feeders based on their contribution to System Average Interruption Duration Index (SAIDI) over the last three years, and highlights the feeders with highest contributions to SAIDI.

500 feeders, serving over 600,000 customers, with the highest average contribution to SAIDI have been targeted to be addressed over the 2023-2027 investment plan. Historically these 500 feeders cumulatively contribute to a quarter of Hydro One's overall SAIDI. Improving performance of this group of feeders is expected to reduce the average duration of outages by over 40% for about 600,000 customers, which represents a significant portion of the 1.4 million customers served by Hydro One.

Currently these 500 feeders lack SCADA and smart devices. As a result, when a fault occurs on one of these feeders, a crew will have to be dispatched to locate the fault by physically travelling the length of the feeder. Once the fault is located, crews will have to resolve the cause of the fault before power can be restored to the customers on the feeder. Each feeder is unique, but all 500 feeders targeted by this investment will benefit from modernization projects.

This investment plays a critical part in enabling Hydro One to meet its system reliability performance targets to improve reliability for its customers. Details on these performance targets can be found in Section 3.5 of the DSP.

B. INVESTMENT DESCRIPTION

This investment focuses on reducing the duration of outages of the WPF feeders by allowing Hydro One to locate and respond to outages faster, remotely sectionalize feeders to restore as many customers as possible, and improve load transfer capabilities. This investment will enable Hydro One to reduce the duration of outages on feeders supplying about 600,000 customers.

The investment will take proactive action to increase the reliability of the distribution network and reduce feeder outage duration using the following solutions:

- Deployment of modern switching equipment that can be remotely controlled to provide isolation and sectionalization;
- Adding monitoring and remote control to existing equipment capable of supporting SCADA, which will enable faster response to outages when they occur;
- Installing remote operable switches at existing tie points to enable faster load transfers; and
- Installation of Communicating Faulted Circuit Indicators (CFCI), which will identify the fault location to system operators to enable faster restoration by field personnel.

By way of example, Hydro One previously installed remote operable switches on the Muskoka M1 feeder as part of this WPF investment in 2019. This feeder is over 100 km long and about half is located off road making locating and correcting the cause of a power outage challenging. Below is a picture showing an example of one location where this line diverts from the roadside making access difficult.

Figure 1: Example of an Off-road Section of the Muskoka M1 Feeder

On December 19th 2020, a tree fell on the Muskoka M1 power line, about 50 km away from the TS. The tree contact caused a sustained fault on the system and as a result the feeder breaker at the station opened, causing the entire feeder supplying approximately 10,000 customers to be out of power. The figures below illustrate how remote operable switches were used to minimize the impact of this outage and improve system reliability. Note that in the accompanying figures, de-energized lines are shown as red and re-energized lines are green.

BEFORE REMOTE OPERABLE SWITCH INSTALLATION

Pre-fault System Configuration

This is the original configuration of the Muskoka M1, before any grid modernization efforts were made. Prior to modernization, the Muskoka M1 was one of the worst performing feeders in the Province. At this time, an automated sectionalizer existed which could isolate faults near Minett DS or Rosseau DS, however, there was no remote operable capabilities with this device. See the figure below for a simplified illustration of the feeder configuration prior to modernization.

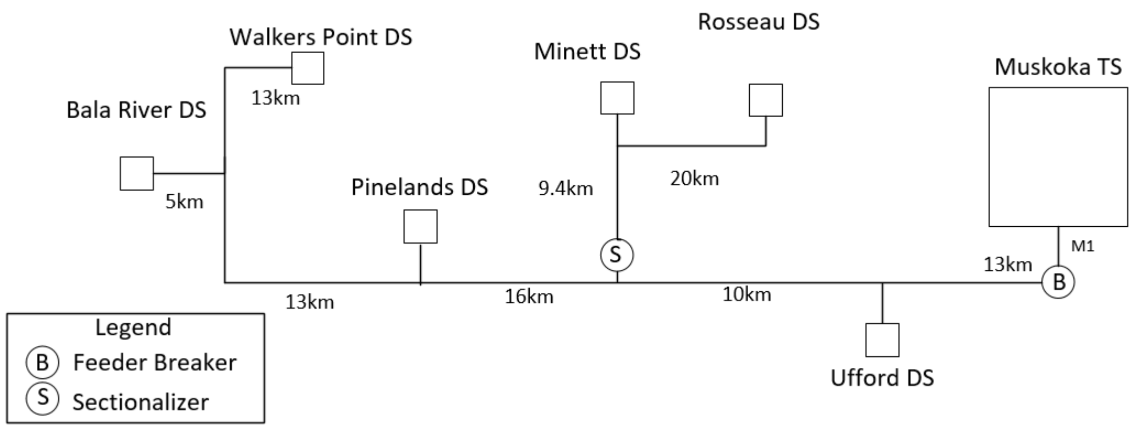

Figure 2: Pre-fault Existing Configuration

Post-fault System Configuration

If the December 19th outage occurred on the M1 feeder prior to modernization, the feeder breaker would open to clear the sustained fault, causing the entire feeder supplying approximately 10,000 customers to be out of power. Without remote operable switches installed, power would remain out until responding crews find the source of the outage, arrive on site and correct the cause of the outage. See the figure below for a simplified illustration of the impact of the outage.

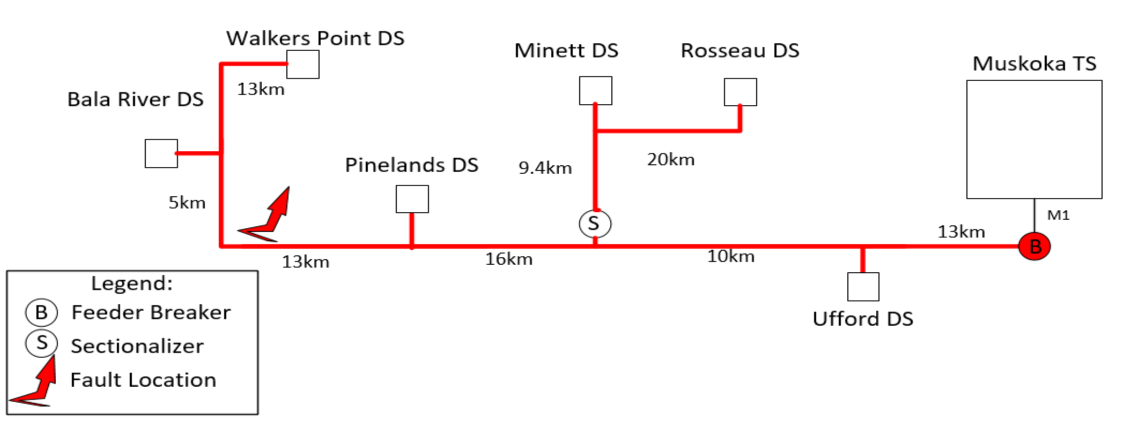

Figure 3: Post-fault Existing Configuration

AFTER REMOTE OPERABLE SWITCH INSTALLATION

Pre-fault System Configuration

Additional switches have been installed at key locations to permit remote sectionalizing. These switches were installed under this investment in 2019 to improve reliability for customers fed from this feeder. See the figure below for a simplified illustration of the feeder configuration post modernization.

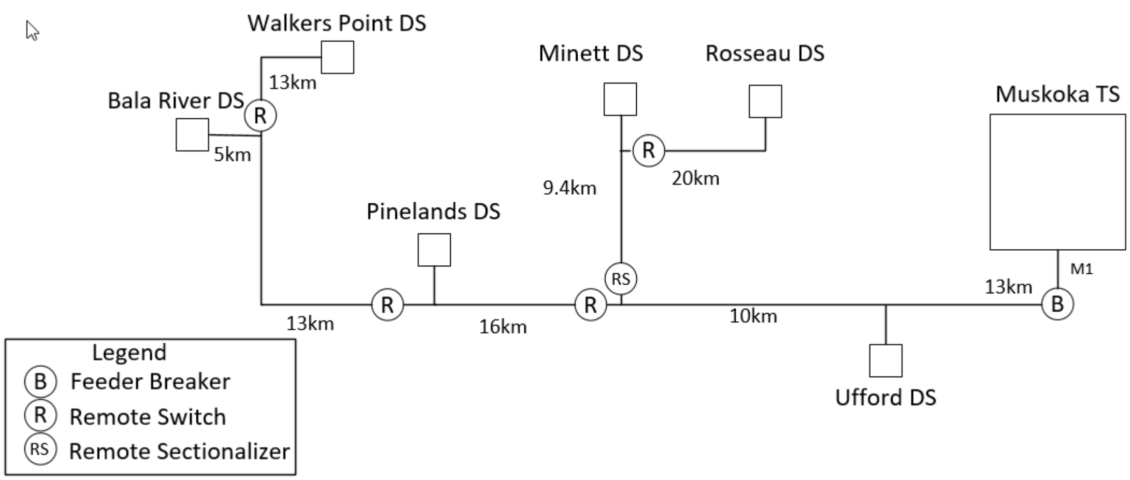

Figure 4: Pre-fault Modernized Feeder Configuration

Post-fault System Configuration

When the December 19th outage occurred on the M1 feeder post modernization, the feeder breaker would still open to clear the sustained fault, causing the entire feeder supplying approximately 10,000 customers to be out of power. See the figure below for a simplified illustration of the impact of the outage immediately following the fault.

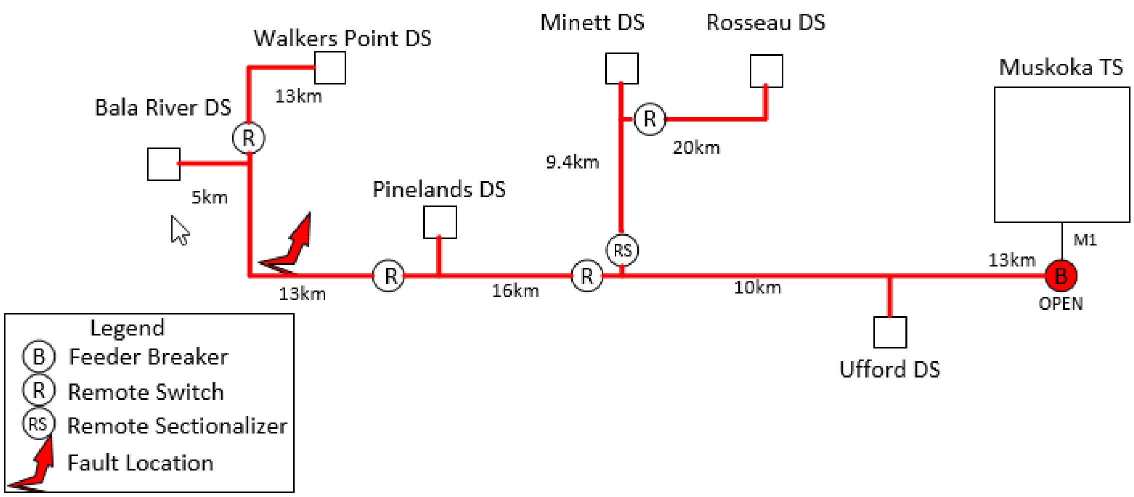

Figure 5: Post-fault Modernized Feeder Configuration Prior to Switching

However following the fault, the remote operable switches installed on this feeder enabled the fault location to be detected and the source of the fault to be sectionalized remotely by opening the upstream switch. This action allowed power to be restored to over 6,000 customers supplied by Rosseau DS, Minett DS, Pineland DS and Ufford DS in about 20 minutes. See the figure below for a simplified illustration of the impact of the outage after the fault impact was limited using remote operable switches.

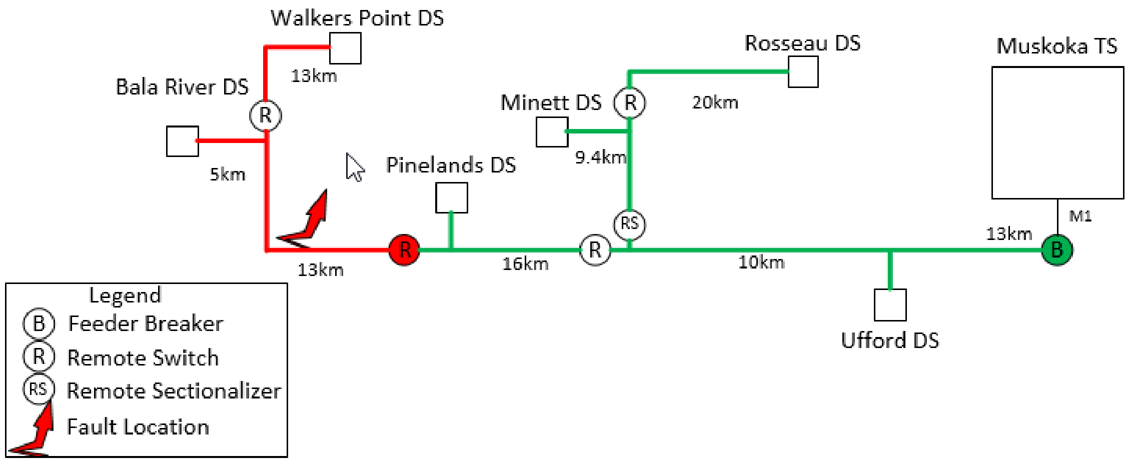

Figure 6: Post-fault Modernized Feeder Configuration Following Switching and Isolation

The remaining 3,900 customers were able to be restored within about 8 hours once the tree contact was addressed.

The Muskoka M1 feeder's annual average contribution to Hydro One's SAIDI from 2017 to 2019 was 0.124 hours (which ranked as one of the top 5 contributing feeders to system SAIDI). Following remote operable switch installation under this investment, in 2020 the annual SAIDI contribution was reduced by about 80% to 0.025.

C. OUTCOMES

This investment will have an impact on the following:

- Reducing outage times by identifying when a fault has occurred and directing crews to the location of the fault through remote monitoring instead of dispatching a crew to drive the length of the feeder to visually identify the source of a fault; and
- Reducing customer hours of outage by using remotely operable devices to enable sectionalisation and load transfers from the grid control room to remotely restore as many customers as possible before a crew is dispatched;

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 1 - Outcome Summary

Customer Focus	• Improve the reliability of electricity supply to customers.
Operational Effectiveness	• Improved system reliability through faster location, isolation and restoration of outages. • Improved operational effectiveness through enablement of remote switching to facilitate load transfers.

D. EXPENDITURE PLAN

Cost estimates are determined based on the average historical cost per feeder for this investment. The yearly budget for this investment is planned to increase so more feeders can be addressed in the 2023-2027 investment plan, increasing the number of customers to 600,000 that would benefit from reliability improvement. Customers that benefit from this investment are expected to see a reduction in the duration of outages by an average of approximately 40%. Based on Phase 2 of the Customer Engagement, there is strong support to increase the pace of this investment.

The factors influencing the cost of the investment include:

- The equipment cost of remote controllable equipment and SCADA devices;
- Wireless signal availability and strength impacts location of device installation and the need for additional equipment;
- Additional work required for off road locations to facilitate installation of new equipment or upgraded devices.

Table 2 summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	39.6	40.9	42.2	43.0	43.8	209.4
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**39.6**	**40.9**	**42.2**	**43.0**	**43.8**	**209.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**39.6**	**40.9**	**42.2**	**43.0**	**43.8**	**209.4**

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: DO NOTHING

Under this alternative Hydro One will not install any remote operable devices or CFCIs and customers supplied from feeders that are on the WPF list will not see a reduction in annual outage duration. This will be in contrast to the desire of the majority of Hydro One customers to improve reliability as demonstrated through the results of Phase 2 of Customer Engagement. This alternative is rejected as it does not capitalize on the opportunity to cost effectively improve reliability for customers in alignment with their preference.

ALTERNATIVE 2: CONTINUE WITH THE WPF INVESTMENT TO IMPROVE RELIABILITY FOR 400,000 CUSTOMERS

This alternative would continue the investment at a slower pace, resulting in reliability improvements for about 400,000 customers. This investment will install sectionalizing devices, improving feeder transfer capability, and providing grid control room operators with additional information about the current state of the system. This information will allow the grid control room to more quickly identify the origin of a fault and perform operational actions in order to restore customers and improve reliability. This alternative is rejected as it does not fully capitalize on the opportunity to cost effectively improve reliability for customers and is not in alignment with customers' preference to do so.

ALTERNATIVE 3: CONTINUE WITH THE WPF INVESTMENT TO IMPROVE RELIABILITY FOR 600,000 CUSTOMERS (RECOMMENDED)

This alternative would continue the investment at the recommended pace, resulting in reliability improvements for about 600,000 customers. The increase in investment level will enable a larger group of feeders to be included and as result more customers will benefit from the reduction in outage duration. Phase 2 of the Customer Engagement demonstrated strong support for this level of investment as this alternative was preferred by all customers segments (see SPF Section 1.6 for additional details). This alternative is selected as it fully capitalizes on the opportunity to cost effectively improve reliability for customers in alignment with their preference.

F. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Investment include access to the assets depending on the season, and outage availability. These risks are mitigated through extensive planning, scheduling, and outage coordination across lines of business and stakeholders. In the event a necessary outage cannot be obtained, the work schedule will be adjusted as appropriate to ensure that the overall work execution plan is not impacted.

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D-SS-06	POWER QUALITY AND STRAY VOLTAGE
Primary Trigger:	Power Quality
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	2023	2024	2025	2026	2027	Total
Net Cost	3.8	3.9	4.0	4.0	4.1	19.8

Summary:

This non-discretionary investment involves the investigation and resolution of power quality and stray voltage issues that adversely impact customer experience. The power quality and stray voltage issues are typically identified through customer complaints. The investment is expected to mitigate the customer issues and ensure the system is operating as intended.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is needed to respond to customer complaints resulting from power quality and stray voltage issues by investigating and performing the necessary corrective work as required in compliance with the Distribution System Code, Section 4.1.

Power quality issues include instances when the voltage, frequency, or phase balance of the supply do not conform to established specifications.

Stray voltage is a specific type of power quality issue where a small electrical potential between two conductive surfaces exists. It usually causes no harm and is the by-product of the normal delivery and use of electricity. However, if the voltage level is high enough, it may result in electric shock and, for farm customers, may affect livestock behaviour and health.

B. INVESTMENT DESCRIPTION

This demand program encompasses the capital costs associated with responding to power quality and stray voltage issues. Hydro One performs a number of measures to address power quality and stray voltage, including examination of the integrity of neutral and grounding systems, balancing loads and upgrading the neutral conductor of the supply system.

The power quality and stray voltage program includes investigation and resolution of the following conditions:

- Power Quality including high voltage, low voltage, phase imbalance, flicker
- Farm Stray Voltage
- Residential Stray Voltage

Power quality investments encompass changes and upgrades that are narrow in scope, and are in response to a specific customer complaint with a focused corrective solution. By contrast, power quality system modifications in D-SS-03 are the changes and upgrades required to maintain the quality of supply to multiple customers, in cases where supply issues affect a general area of the distribution system.

C. OUTCOMES

The Power Quality and Stray Voltage program will result in:

- Mitigating risks associated with power quality and stray voltage issues, and
- Compliance with Distribution System Code sections 4.1 Quality of Supply and 4.7 Farm Stray Voltage.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Respond to customer complaints related to power quality and stray voltage.
Operational Effectiveness	• Maintain acceptable performance of the distribution system by addressing power quality and stray voltage issues • Maintain the safe operation of the distribution system by mitigating potential safety hazards caused by stray voltage.
Public Policy Responsiveness	• Comply with the Distribution System Code sections 4.1 Quality of Supply and 4.7 Farm Stray Voltage

D. EXPENDITURE PLAN

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	4.3	4.4	4.5	4.6	4.7	22.6
Less Removals	0.5	0.5	0.5	0.6	0.6	2.7
Capital and Minor Fixed Assets	**3.8**	**3.9**	**4.0**	**4.1**	**4.1**	**19.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.1
Net Investment Cost	**3.8**	**3.9**	**4.0**	**4.0**	**4.1**	**19.8**

The factors affecting the cost of the investment include:

- The amount of power quality and stray voltage issues that arise in a given year
- The scope of the work involved to fix the issues

The forecast expenditures for this demand program are projected from historical costs.

E. ALTERNATIVES

No alternatives are considered, since this investment is non-discretionary. Failure to respond to power quality and stray voltage complaints violates the Distribution System Code and may result in unacceptable system performance.

F. EXECUTION RISK AND MITIGATION

No major risks are anticipated for this investment.