Distribution System Plan (DSP)

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EB-2026-0164

SECTION 3.0 – DSP - DISTRIBUTION SYSTEM PLAN

3.0.1 FILING REQUIREMENTS

Hydro One Networks Inc. (Hydro One) has prepared a five-year Distribution System Plan (DSP) for the 2028 to 2032 planning period. This DSP has been developed in accordance with the relevant requirements of Chapters 1 (Distribution Rate Applications and Common Exhibits), Chapter 2 (Cost of Service Applications) and Chapter 5 (Consolidated Distribution System Plan Filing Requirements of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Distribution Rate Applications issued on December 16th, 2025 (collectively, the "Distribution Filing Requirements"). This section includes a description of the structure of the DSP and a concordance table mapping the sections of the DSP to the Distribution Filing Requirements.

The DSP provides a consolidated set of documentation concerning Hydro One Distribution's power system assets, benchmarking, system reliability, 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. It sets out Hydro One's proposed distribution investments for the 2028–2032 planning period in the context of asset condition, distribution system reliability, and evolving customer and regional planning requirements, and describes the information, analyses, and planning considerations that support the development of the proposed capital plan. Similar information regarding Hydro One Distribution's General Plant assets is presented in the General Plant System Plan (GSP) framework, included in Section 4.0 of the System Plans.

3.0.2 FORMAT OF THE DSP

Consistent with the Distribution Filing Requirements, this DSP is structured to first present the analytical foundation for the proposed capital plan, including asset condition, lifecycle strategies, benchmarking, and reliability performance (Sections 3.2 through 3.7), followed by presentation of the capital investment plan and supporting expenditure trends and variance analysis (Sections 3.8 and 3.9). Subsequent sections address capital work

execution and supporting investment documentation. The structure of the DSP is outlined below.

DSP Section	Content Description
Section 3.1	**DSP 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	**DSP Asset Information and Lifecycle Strategies** – This section presents the state of Hydro One's distribution system assets and their asset management and lifecycle strategies.
Section 3.3	**DSP Benchmarking and Other Studies** – This section presents the external studies that have been undertaken to inform the investment plan.
Section 3.4	**DSP 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	**DSP Performance Measurement and Outcomes** – This section presents Hydro One's approach to performance measurement, including discussion of the distribution scorecards.
Section 3.6	**DSP Other Capital Planning Factors and Considerations** – This section details other factors which have informed the investment plan.
Section 3.7	**DSP Investment Planning Process** – This section summarizes the information found in SPF Section 1.7 – Investment Planning Process related to Hydro One Distribution, including customer engagement and statutory and regulatory obligations.
Section 3.8	**DSP Capital Expenditures and Trends** – This section summarizes Hydro One's capital investment plan for its distribution system for the five-year forecasting period (2028-2032).
Section 3.9	**DSP Capital Expenditure Variances** – This section compares Hydro One's historical distribution capital spending to previous OEB-approved funding and provides a five-year snapshot (2023-2027) of Hydro One's capital spending for its distribution business.
Section 3.10	**DSP 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	**DSP Material Investment Summary Documents** – This section includes detailed summaries of large investments (with forecast spending over $1M) over the 2028-2032 forecasting period in the OEB's System Access, System Service and System Renewal investment categories.

Hydro One has prepared a Table of Concordance in Appendix A to assist parties in reviewing the DSP. This table aligns the sections of this DSP with the Distribution Filing Requirements.

Unless otherwise specified, the asset information contained in this DSP is taken as of December 31, 2025.

APPENDIX A - TABLE OF CONCORDANCE

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3.1.1 Introduction	Ch. 5.2.1
3.1.2 Distribution System and Service Area	Ch. 2.1.5, 5.3.2
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3.1.4 Capital Expenditure Plan Summary	Ch. 5.4.1
3.1.5 The DSP is Reasonable and Appropriate	Ch. 5.2.1, 5.3.1, 5.3.2, 5.4, 5.4.1
3.2 DSP Asset Information and Lifecycle Strategies	Ch. 5.3.2, 5.3.3
3.2.1 Introduction	Ch. 5.3.2 Supplemented by Exhibit A-02-03 Section 6.0 for Host & Embedded Distributors
3.2.2 Asset Component Information – Distribution Stations	Ch. 5.3.2, 5.3.3
Asset Description/Purpose	Ch. 5.3.2
Asset Demographics, Condition, Performance and Other Factors	Ch. 5.3.1.2
Life Cycle Strategy	Ch. 5.3.3
3.2.3 Asset Component Information – Distribution Lines	Ch. 5.3.2, 5.3.3
Asset Description/Purpose	Ch. 5.3.2
Asset Demographics, Condition, Performance and Other Factors	Ch. 5.3.1.2
Life Cycle Strategy	Ch. 5.3.3
3.2.4 Asset Component Information – Wholesale & Retail Revenue Meters	Ch. 5.3.2, 5.3.3
Asset Description/Purpose	Ch. 5.3.2
Asset Demographics, Condition, Performance and Other Factors	Ch. 5.3.1.2
Life Cycle Strategy	Ch. 5.3.3
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3.3.3 Attachments: Studies	Ch. 5.3.6, 5.4.2.1
3.4 DSP Connecting Distributed Energy Resources	Ch. 5.2.2.2., 5.3.4
3.4.1 Overview	
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Hydro One Reference	OEB Filing Requirements
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3.4.4 DER Hosting Capacity	Ch. 5.3.4
3.4.5 Renewable Energy Generation (REG) Investments	Ch. 5.2.2.2
3.4.6 FEI Investments and Capacity Increase	Ch. 5.3.5, 5.4.2.2 (when discussing NWS)
Attachments: Annual Data on DER Connections, List of Behind the Meter and Grid Connected DERs, RGCRP Funding Request and Revenue Models	Ch. 5.3.4, Ch. 5 - Appendix A
3.5 DSP Performance Measurement and Outcomes	Ch. 5.2.3 Ch.5.2.3.2 Covered within Exhibit A-05-01
3.5.1 Introduction	
3.5.2 OEB Electricity Distribution Scorecard	Ch. 2.1.7, 5.2.3.1, 5.2.3.3
3.5.3 Hydro One Distribution OEB Scorecard	Ch. 5.2.3.1, 5.2.3.3
3.5.4 Addressing the Activity and Performance-Based Benchmarking Report	Ch. 2.1.7
Attachments: Annual Scorecard and MDA	Ch. 2.1.7
3.6 DSP Other Capital Planning Factors and Considerations	Ch. 5.3.1.1, 5.3.5, 5.3.6
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3.6.5 Non-Wires Solutions to Address System Needs	Ch. 2.1.8, 5.3.1.1, 5.3.5
3.6.6 Climate Vulnerability Assessment and System Hardening	Ch. 5.3.6
3.6.7 Distribution System Losses	Ch. 5.3.1.1
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Hydro One Reference	OEB Filing Requirements
3.8 DSP Capital Expenditures and Trends	Ch. 5.4 (See Exhibit E-03-02 for Asset Related O&M Expenditures)
3.8.1 Introduction	Ch.5.4.1
3.8.2 Hydro One Investment Priorities	Ch. 5.3.3, 5.4.2, 5.4.2.1
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Attachments: Appendix 2-AA	Ch. 5.4.1
3.9 DSP Capital Expenditures Variances	Ch. 5.4.1, 5.4.2
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3.9.2 Historical Capital Expenditures Trends and Variances	Ch. 5.2, 5.4.1, 5.4.2
Attachments: Distribution Capital Performance Reports, Appendix 2-AB	Ch. 5.4.1
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SECTION 3.1 – DSP – OVERVIEW

3.1.1 INTRODUCTION

This Exhibit outlines Hydro One's Distribution System Plan (DSP) for the 2028–2032 planning period. The DSP presents a portfolio of capital investments totaling approximately $10,863.3M that have been identified and 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 *Renewed Regulatory Framework* (RRF).[1]

Serving roughly 1.5 million residential, commercial, and industrial customers across diverse urban, rural, and remote communities, Hydro One’s distribution system constitutes essential infrastructure for Ontario, connecting numerous communities throughout the province. This DSP focuses on three investment priorities: maintaining the grid, improving reliability and resiliency, and meeting Ontario’s growing demand.

The proposed capital investments are informed by asset, system, customer, policy, and legislative requirements and were selected in consideration of the following: mitigating safety and reliability risks associated with aging assets and increasingly frequent and severe storms, alleviating capacity constraints resulting from growing load demand and electrification, meeting statutory and regulatory obligations such as timely customer connections to the grid, and facilitating the expansion of broadband and other critical infrastructure throughout Ontario.

Hydro One developed this DSP based on outcomes that customers value. The company engaged Innovative Research Group (IRG) to conduct an extensive, two-phase customer engagement process, which directly informed the plan. The resulting DSP is founded on outcomes valued by customers - most notably price and reliability - and aligns with their expressed priorities and preferences. Ultimately, more than 68% of customers surveyed

[1] OEB, Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012.

indicated support for Hydro One's draft investment plan or endorsed additional measures to further improve service outcomes. Following customer engagement and further investment plan review, Hydro One refined and re-paced certain investments to balance customer priorities, system needs, execution considerations, and affordability. The resulting DSP is approximately $1.5B lower than the draft plan presented during customer engagement. The changes primarily affect reliability and resiliency investments, Digital and Technology (including prepaid cloud computing expenditures) enhancements, and Facilities and Real Estate enhancement.

The proposed investments in this DSP represent a substantial increase over the 2023–2027 period, driven by system and customer needs. The key drivers include mandatory and customer-driven work; asset condition, safety, reliability, restoration and resiliency needs and increased requirements for system capacity, distributed energy resources (DER) integration, monitoring and operational capability.

This DSP provides a comprehensive, prudent, and necessary response to the significant challenges facing Hydro One's distribution system and its customers. It supports the renewal of aging assets that pose safety and reliability risks, enables economic development and electrification-driven demand through investments that facilitate customer connections and infrastructure development, and enhances reliability and resiliency across Hydro One's extensive vegetation-dense and long-radial network.

The DSP is the result of a robust planning process integrating asset condition assessment, customer engagement, system utilization, regional planning, risk-based prioritization, and other salient factors. This approach helps ensure the plan balances customer needs, asset and system requirements, and cost impacts. The result is an investment plan that positions Hydro One to deliver results consistent with good utility practice and customer preferences.

The DSP provides detailed evidence supporting the key components of the plan, including asset information and lifecycle data (DSP Section 3.2), benchmarking and other third party studies(DSP Section 3.3), connecting DER (DSP Section 3.4), performance measurement and outcomes (DSP Section 3.5), capital planning factors and considerations (DSP

Section 3.6), investment planning process (DSP Section 3.7), capital expenditures and trends (DSP Section 3.8), historical capital expenditure variances (DSP Section 3.9), capital work execution strategy (DSP Section 3.10), along with detailed Investment Summary Documents (ISDs) for the 32 investments that comprise this DSP (DSP Section 3.11).

In accordance with the Filing Requirements, Hydro One does not have any transmission or high-voltage assets previously deemed by the OEB as distribution assets under Section 84 of the Ontario Energy Board Act, 1998, and is not seeking such a determination in this application.

3.1.2 DISTRIBUTION SYSTEM AND SERVICE AREA

This section describes the physical, geographic, customer and operating characteristics of Hydro One's distribution system. These characteristics establish the system context for the DSP because they influence how Hydro One plans, prioritizes, executes and costs distribution investments. Unless otherwise indicated, the asset statistics presented throughout this DSP exclude assets acquired through Orillia Power and Peterborough Distribution acquisitions.

Hydro One's distribution system provides electricity service across a large and diverse service territory covering approximately 75% of Ontario's geographic area, as shown in Figure 1. The system serves approximately 1.5 million residential, commercial and industrial customers in urban, rural, remote, Métis and First Nations communities. It also supplies embedded local distribution companies (LDCs) and supports a significant number of DERs connected to the distribution system.

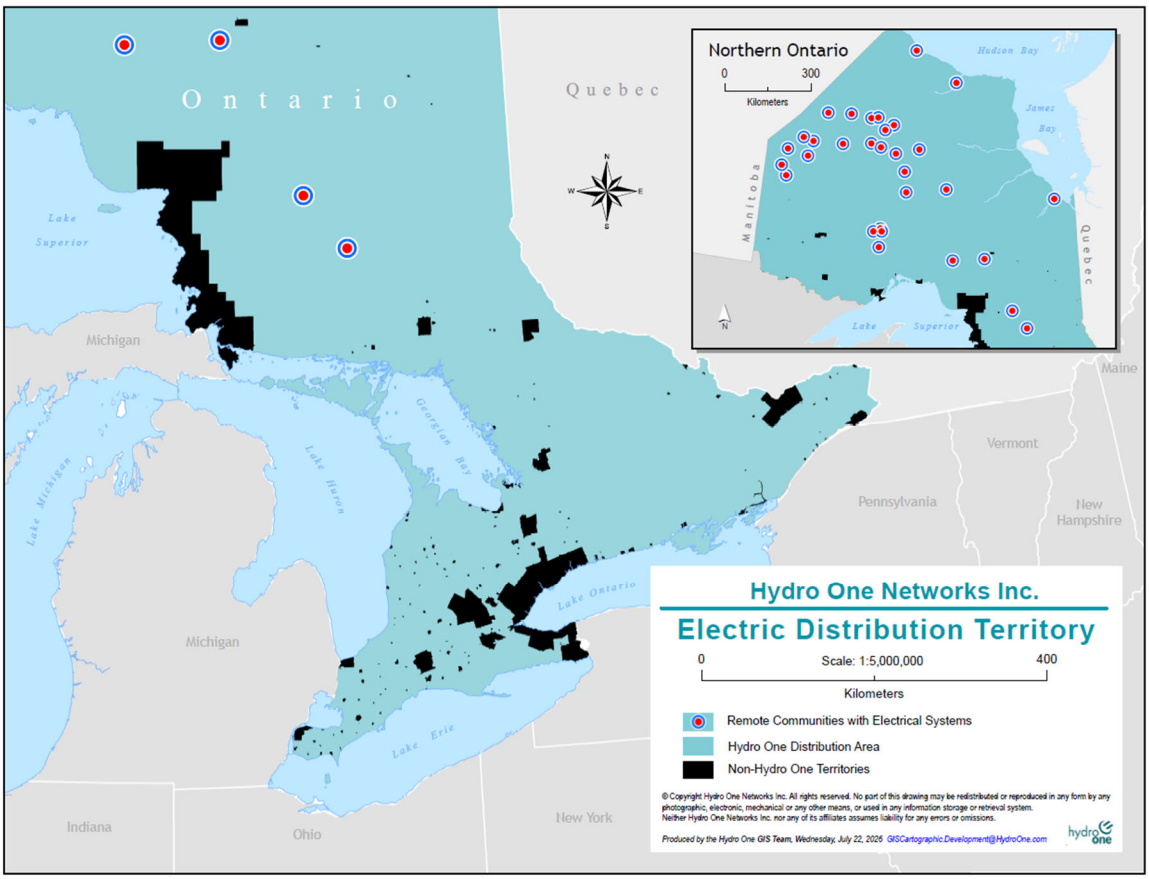


Figure 1: Map of Hydro One Distribution Service Territory

Because of Hydro One's historical role as Ontario's distributor of last resort and the integration over time of additional service areas, the distribution system includes a broader mix of geography, terrain, density, forest profiles, weather exposure, growth profiles, voltage levels and asset configurations than typical for Ontario distributors. This diversity directly affects the investment plan. A small number of customers may require long lines, dedicated station capacity, communications infrastructure and recurring inspection and vegetation work. Many communities are supplied over radial feeders with limited back-feed capability. In other parts of the system, aging underground cable systems, legacy low-voltage systems and specialized assets require distinct renewal strategies.

The investment planning framework for the DSP must therefore account for the scale of Hydro One's distribution system, local reliability needs, mandated service obligations,

long-term lifecycle cost, and the practical constraints of executing work across a very large and geographically dispersed system.

3.1.2.1 KEY SYSTEM CHARACTERISTICS

Table 1 below summarizes key Hydro One distribution system characteristics. These characteristics provide the factual context for the investment planning considerations discussed in the remainder of this section.

Table 1 - Hydro One Distribution System Assets – Key Statistics

System Characteristic	Hydro One Distribution System Profile
Service territory	961,289 sq. km; Approximately 75% of Ontario's geographic area
Urban/rural service-area composition	Urban: approximately 0.1%, or about 1,000 sq. km; Rural: approximately 99.9 percent, or about 960,000 sq. km
System peak	7,131 MW in 2025 (including embedded LDCs)
Distribution customers	1,515,231
Connected DER	Approximately 2,837 MW
Local Distribution Companies (LDCs) supplied	25 partially embedded LDCs, and 17 fully embedded LDCs supplied through Hydro One's distribution facilities. Fully embedded LDCs serve roughly 207,000 customers.
Primary distribution voltage classes	4.16kV, 8.32kV, 12.5kV, 13.8kV, 25kV, 27.6kV, and 44kV
Distribution line length[2]	125,988 circuit-km
Overhead/underground line mix	Overhead lines: approximately 91% (114,400 circuit-km); Submarine cables: approximately 3% (4,100 circuit-km); Underground lines: approximately 6% (7,400 circuit-km)
Major asset populations	Overhead poles: approximately 1.6 million; Distribution stations: approximately 1,000; and Service Transformers: approximately 549,000
Operating centres	54

Hydro One's system spans more than 960,000 square kms and provides service to approximately 1.5 million customers across rural and urban locations. The profile illustrates both the scale of the infrastructure to be managed and the diversity of the system. Hydro One maintains approximately 126,000 circuit-kms of distribution line, approximately 1.6 million poles, approximately 1,000 distribution and regulating stations,

[2] Asset count as of July 17th, 2026

and 549,000 service transformers. The size, scope and density of the system affect work program volumes, service imperatives, execution logistics and the cost of sustaining safe and reliable service across the province.

In addition to end-use customers, Hydro One has also successfully integrated approximately 2,837 MW of distributed energy resources (DER) into the distribution system and continues to support new customer requests within current regulatory frameworks. These connection requests must be assessed to ensure that distribution system performance, protection, safety and reliability are not adversely affected.

The following subsections describe the key characteristics of Hydro One's distribution system and their implications for investment planning.

3.1.2.2 GEOGRAPHIC DISPERSION AND INFRASTRUCTURE INTENSITY

Hydro One's system extends across southern, central, eastern, and northern Ontario. Distribution facilities are on urban streets, rural road allowances, off-road corridors, forested and agricultural areas, islands, and remote locations. The combination of geographic reach, uneven customer density, and infrastructure scale differs materially from the more compact service territories of most Ontario distributors.

The density of line infrastructure per square km of service territory is materially lower than the largest Ontario distributors. Hydro One has approximately 0.1 km of line per square km of service territory, while the next lowest comparator in the ten largest Ontario distributors has approximately 3.4 km of line per square km as shown in Figure 2. Conversely, Hydro One has approximately 85 meters of distribution line per customer, which is significantly higher than the next largest comparator at approximately 27 meters per customer.

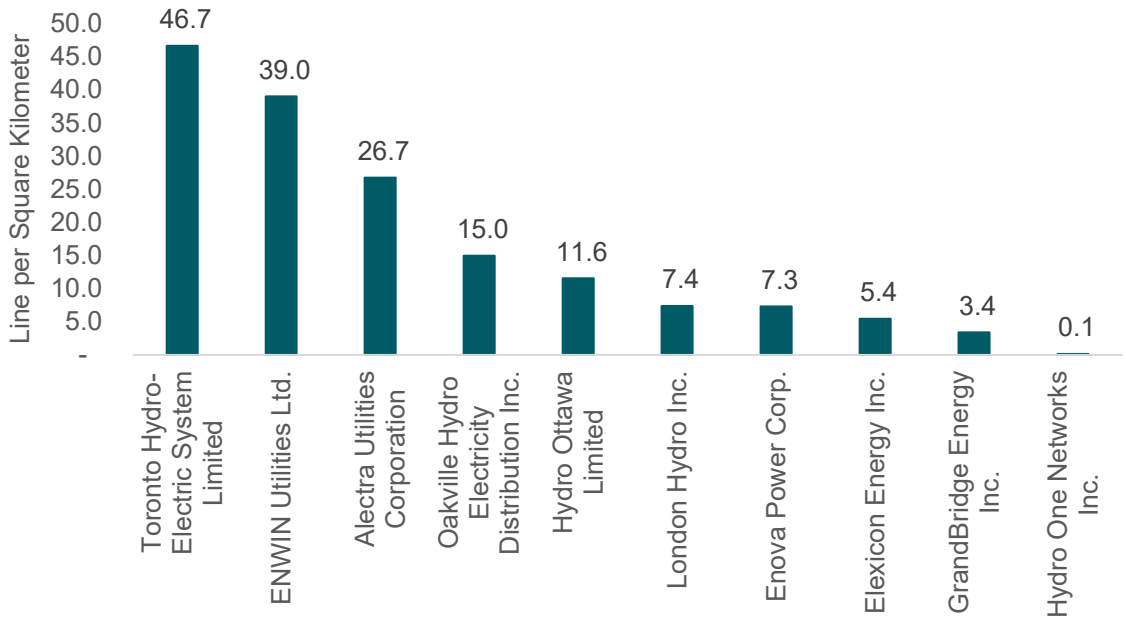


Figure 2: Distribution Line Density by Service Territory - Ten Largest Ontario Distributors[3]

These measures demonstrate that Hydro One must maintain substantially more dispersed infrastructure per customer served. This characteristic affects both capital and maintenance activities. For example, recurring activities such as equipment inspections, vegetation clearing, and power restoration must be delivered over long distances, often to serve relatively few customers at a given location. The same amount of customer-facing work that a compact urban distributor might complete in a concentrated area can require Hydro One to mobilize crews, materials and equipment across a much larger access footprint.

This infrastructure footprint increases the number of assets, rights-of-way, vegetation exposure, inspection locations and potential failure points that must be managed. It also increases travel, mobilization, outage coordination, access, material-positioning and restoration requirements. A relatively small number of customers in a specific area may

[3] *Calculated by Hydro One using OEB reported 2024 utility data "Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.5.5 Utility Characteristics". The peer group consists of the ten largest Ontario distributors by customer count.*

still require substantial line, station and communications infrastructure, and Hydro One must maintain that infrastructure to provide safe and reliable service.

3.1.2.3 LONG RADIAL AND OFF-ROAD FEEDERS WITH LIMITED ALTERNATE SUPPLY

Hydro One's distribution system is predominantly radial and has limited alternate-supply capability in many areas. Radial construction is a practical and cost-effective means of serving dispersed customers over long distances. However, where no feeder tie or transfer path is available, an upstream fault can interrupt all customers downstream of the fault and service cannot be restored until the fault is located, isolated, and repaired. Many rural and northern feeders extend for more than 100 kms and include numerous branches and vegetation interfaces. Figure 3 below provides the distribution line kms by feeder-length band. More than 24,000 line- kms are on feeders longer than 100 km, including approximately 10,900 line- kms longer than 140 km.

Consequently, long radial feeders create inherent reliability challenges. Long radial feeders have a larger population of line assets and a larger area to patrol following an interruption. Asset deterioration, vegetation contacts, severe weather, and limited access can combine to produce both more frequent interruptions and longer restoration times. Limited feeder ties and alternate supply also reduce the number of customers that can be restored remotely before physical repairs are completed. These factors create a structural reliability challenge that cannot be addressed solely by replacing individual assets on a like-for-like basis.

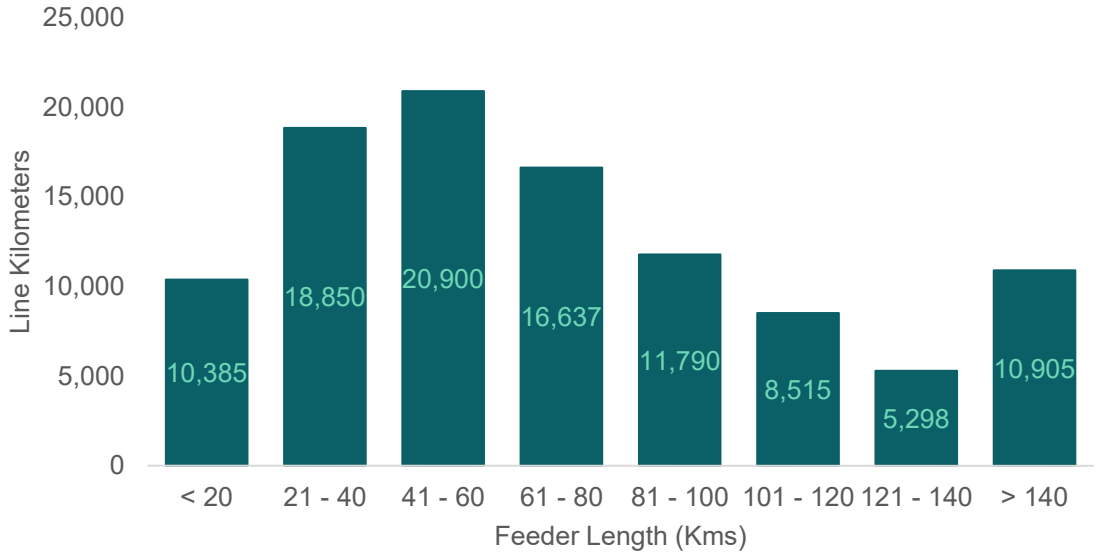


Figure 3: Kilometers of Line by Feeder Length

Hydro One's system also contains a material population of off-road line. Approximately 400 feeders have a significant proportion of off-road plant. When an off-road asset fails, patrol and repair may require property access, travel on foot, tracked vehicles, remote-boom derricks, helicopters, or other specialized equipment. These access requirements generally increase outage duration, repair complexity and execution cost relative to comparable on-road assets. As a result, off-road feeder sections can experience 2.3 times the average outage length compared to feeder sections that are roadside. Figures 4 and 5 show the duration and frequency for feeders with significant off-road sections vs. primarily on-road feeders.

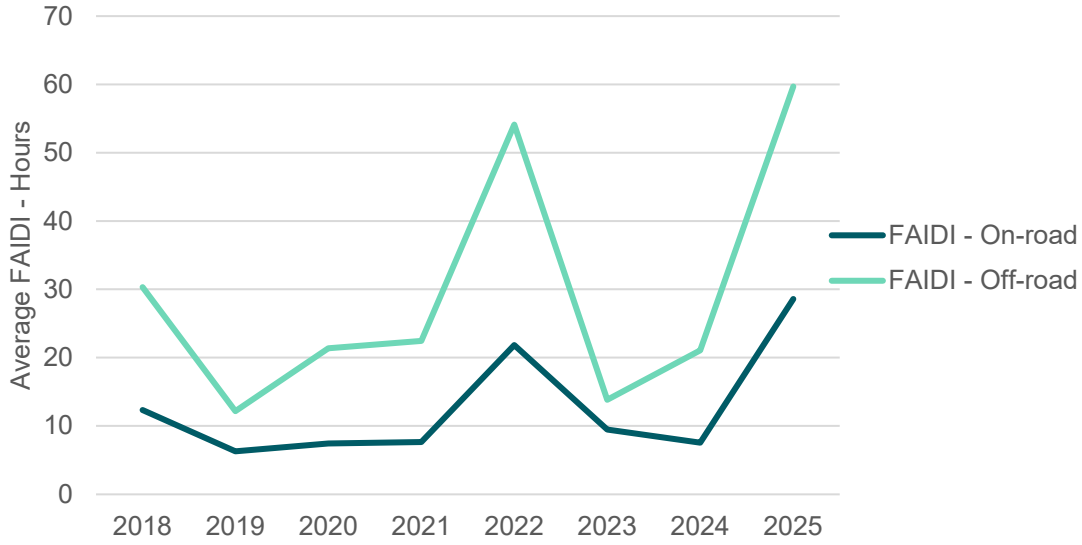


Figure 4: FAIDI Comparison Off-road vs. On-road Feeders

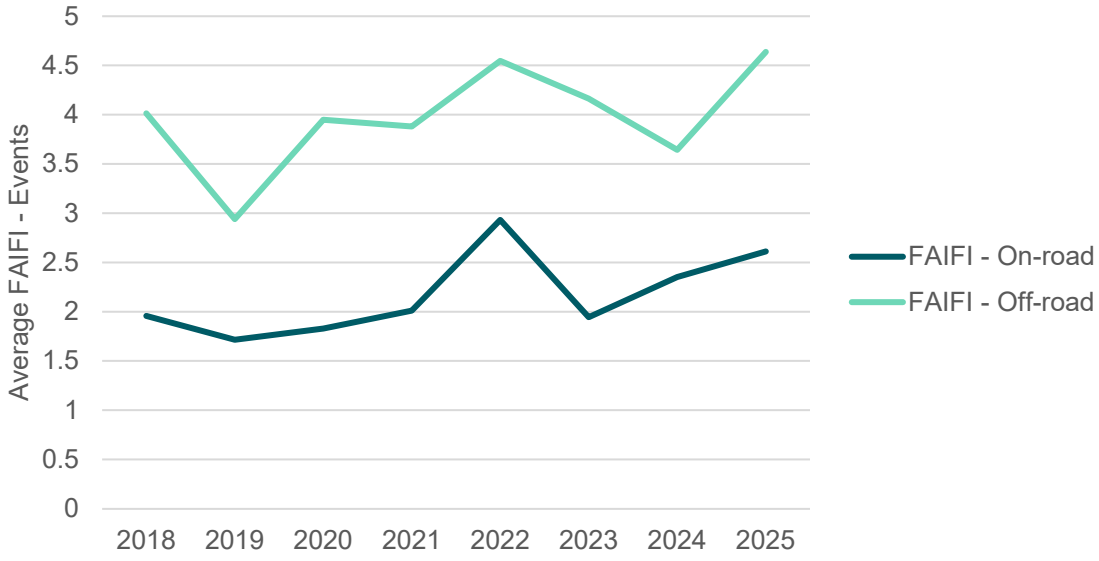


Figure 5: FAIFI Comparison Off-road vs. On-road Feeders

Hydro One therefore considers not only asset condition and failure probability, but also access, transfer capability, the number and type of downstream customers, critical loads, and expected restoration duration. Where an off-road section contains a high concentration of end of life assets, relocation can provide a better lifecycle outcome than

replacing individual components in place because it addresses both the immediate asset need and the future accessibility of the line.

3.1.2.4 DIVERSE URBAN, RURAL, REMOTE, AND FIRST NATIONS AND MÉTIS SERVICE CONTEXTS

Hydro One serves customers in materially different physical and community contexts. Rural areas account for approximately 99.9% of the service territory, while Hydro One also serves urban and suburban communities, Métis customers, and 89 First Nations communities representing close to 23,000 distribution system customers. These customer segments can be exposed to different system configurations, reliability drivers, restoration constraints, capacity needs, and critical-service requirements.

Rural, remote, Métis, and First Nations customers can often be supplied by long radial feeders with limited transfer capability and lengthy restoration access. Traditional investments such as vegetation management, asset renewal, sectionalizing devices and fault indicators can reduce outage frequency and shorten restoration time. However, these measures may not fully overcome the underlying exposure created by a long radial supply path through heavily forested or difficult-to-access areas. In these circumstances, where traditional solutions are not expected to sufficiently improve reliability or are not cost-effective on a standalone basis, Hydro One considers local energy storage as a targeted means of mitigating upstream outages regardless of cause.

Urban and suburban areas present a different set of planning challenges. These areas may have shorter and more concentrated systems, but can include aging underground cable, legacy low-voltage networks, constrained stations, limited construction space, traffic and property impacts, and high concentrations of customers and critical loads. A failure in a compact urban area may therefore affect more customers or require complex excavation and outage coordination, even where the affected line length is relatively short.

Customers in each of these settings reasonably expect safe and reliable service. However, the prudent approach can differ substantially by location. System-wide averages can mask a feeder or community with repeated long outages, a concentrated urban cable problem,

or a remote supply arrangement with no practical tie. Hydro One's planning therefore considers both system-level needs and location-specific customer impacts.

As part of Phase II Customer Engagement Survey, Hydro One noted that seasonal (rural) customers presented a higher level of dissatisfaction (14%) with Hydro One's service compared to residential customers (7%). When presented with a draft plan focused on improving day-to-day reliability of the system, 78% of residential customers and 76% of seasonal (rural) customers supported improving reliability by 2032 and/or spending more to further reduce the risk of outages. Over 1,000 residential customers mentioned improving reliability and reducing outages when prompted for additional feedback as part of the survey.

3.1.2.5 HOST DISTRIBUTOR ROLE FOR EMBEDDED LOCAL DISTRIBUTION COMPANIES

In addition to end-use customers, Hydro One Distribution supplies electricity to 42 LDCs across Ontario and is the host distributor for a material number of LDCs embedded in its distribution system. Of the 42 embedded LDCs, 25 are supplied through transmission and distribution and 17 are supplied through distribution only. Section 6.3.3 of the Distribution System Code requires the reliability of supply and voltage at the delivery point to an embedded distributor to be as good as or better than that provided to the host distributor's other distribution customers. Section 6.6.6 also requires embedded distributors to provide load forecasts and other information required for safe and reliable operation.

An embedded LDC may be represented by one or a limited number of metered supply points, while the LDC serves many downstream residential, commercial, industrial, and critical-service customers. Treating the supply point only as a single Hydro One account can understate the load, downstream customer exposure, and community consequences of a failure of the Hydro One station, feeder, switch, or line section that supplies the embedded distributor.

Hydro One's planning assessment considers the downstream consequence of the asset failure, in addition to the direct customer record at the supply point.

3.1.2.6 PREDOMINANTLY OVERHEAD INFRASTRUCTURE, VEGETATION, AND SEVERE WEATHER EXPOSURE

Approximately 91% of Hydro One's distribution line is overhead. This configuration is directly exposed to wind, ice accretion, lightning, tree contact, falling branches, vehicle contact, and other external hazards. As shown in Figure 6, Hydro One's proportion of overhead lines is materially higher than that of the other large Ontario distributors, all of which are below 60%.

The extent of overhead infrastructure increases both the number of assets exposed to severe weather and the number of rights-of-way that must be inspected and managed. The consequence is particularly material where tree contact or storm damage occurs on a long radial feeder with limited alternate supply and difficult access.

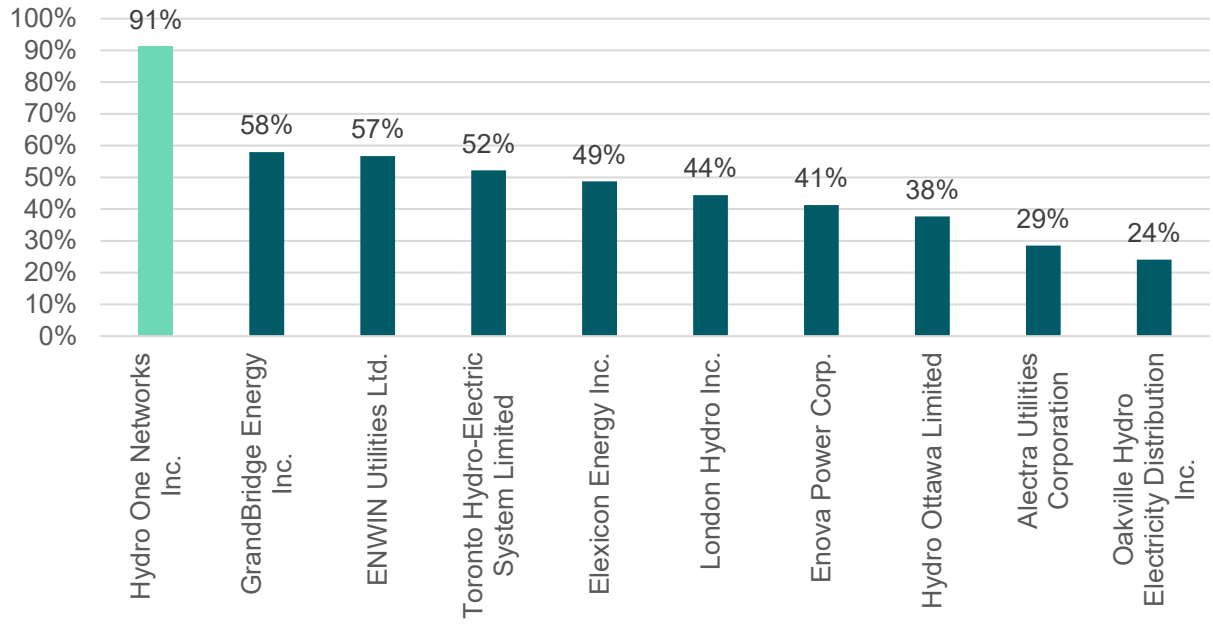


Figure 6: Share of Overhead Distribution Line - Ten Largest Ontario Distributors[4]

[4] *Calculated by Hydro One using OEB reported 2024 utility data "Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.5.5 Utility Characteristics". The peer group consists of the ten largest Ontario distributors by customer count.*

Hydro One's service territory spans multiple climatic and vegetation regions and is exposed to blizzards, freezing rain, ice storms, high winds, lightning, hail, and other severe-weather conditions. Hydro One has experienced increasingly frequent severe weather events in recent years including 48 storm days[5] in 2024 and 47 storm days in 2025 compared to a 10-year (2016-2025) average of 37 storm days, as well as the May 2022 derecho and March 2025 ice storm. Widespread weather events damage many assets at the same time creating high volumes of repair work and restoration times are impacted by difficulty accessing roads and off-road corridors.

Table 2 - Comparison of Recent Historical Major Events[6]

Date	Nov 2020	Dec 2021	May 2022	Dec 2022	April 2023	March 2025
Type of Event	**Wind Storm**	**Wind Storm**	**Derecho**	**Winter Storm**	**Freezing Rain**	**Ice Storm**
Customer Interruptions (in 1000s)	572	761	890	525	359	1,220
Customer Hours of Interruption (in 1000s)	7,043	8,908	24,141	5,701	5,966	49,008
SAIFI	0.4	0.5	0.6	0.4	0.2	0.8
SAIDI	5.0	6.2	17.0	3.8	4.1	32.7
Net cost ($M)[7]	$24.4	$25.6	$109.3	$45.5	$29.9	$196.2

Table 2 demonstrates that major storm events create material customer, operational and cost consequences for Hydro One's predominantly overhead distribution system. Each of the recent major events affected hundreds of thousands of customers and required significant restoration and repair activity. The May 2022 derecho and the March 2025 ice storm were particularly severe, together resulting in approximately 73M customer-hours of interruption and approximately $306M in net cost. The March 2025 ice storm alone resulted in approximately 1.22 million customer interruptions, produced approximately 49M customer-hours of interruption, and resulted in 32.7 hours of SAIDI.

[5] Hydro One defines storm days as a calendar day, with evidence of adverse weather, which results in 150 or more interruptions or more than 3% of customers interrupted.
[6] 2020-2023 Figures per the Major Event Response Reports as filed on the Hydro One website: Reports and Scorecards | Hydro One
[7] Net costs include Hydro One Networks, Orillia RZ and Peterborough RZ.

The scale of these events illustrates that severe weather is a material capital planning consideration. Storm restoration and permanent repair are non-discretionary work requirements that can create year-to-year cost and resource variability and can reduce the resources available for planned work if not appropriately reflected in investment and execution planning. This supports a targeted approach to vegetation management, system hardening, feeder reconfiguration, selective undergrounding, automation, spare equipment and emergency response capability, while recognizing that the timing, location and severity of future events remain variable.

Vegetation management is a recurring and material operational requirement for the overhead system. The scale of the overhead system increases the amount and cycle of inspection and vegetation-management work required, while vegetation contact on long radial feeders can affect a large number of customers downstream of the fault. Vegetation management remains a necessary and recurring mitigation measure, but it does not fully eliminate storm-related exposure, particularly where off-road access and long radial supply paths extend restoration time.

System hardening is an important planning consideration for Hydro One. Hardening can include targeted changes to design standards, coordinated rebuilds of deteriorated line sections, improved sectionalization and switching capability, and selective undergrounding of high-risk feeder sections where the reliability, resiliency, vegetation-management and lifecycle benefits justify the investment. These alternatives are assessed on a site-specific basis using asset condition, historical performance, weather and vegetation exposure, customers and critical loads affected, constructability, expected reliability and resiliency benefits, and lifecycle considerations. This avoids applying a uniform hardening or undergrounding solution across a geographically diverse system.

Severe-weather exposure also affects the pacing and executability of planned capital work. Hydro One must retain sufficient internal and external capacity for emergency response, coordinate planned outages around seasonal and storm risks, and maintain access to

materials, spares, mobile equipment, and specialized resources required to restore the system and complete permanent repairs.

3.1.2.7 SPECIALIZED SUBMARINE CABLE SYSTEM

Hydro One's distribution system includes a specialized population of submarine cable installations used to supply islands and to cross bodies of water where overhead construction is not technically or economically feasible. There are a total of 4,145 km of submarine cables, representing approximately three percent of total distribution line length. Submarine cable deterioration presents a combination of public-safety, reliability, environmental and execution risks. Damage and corrosion occur most frequently at the shoreline, where cable armour can be exposed to abrasion, water ingress and public contact. Inspection and replacement require specialized marine equipment, shoreline access, seasonal scheduling, environmental coordination and specialized cable supply.

Hydro One must address immediate hazards through emergency response. Where the condition issue is non-emergent, the utility may manage the risk through planned replacement, partial replacement, shoreline protection or other mechanical protection. These characteristics support the need for a targeted planning approach for submarine cables rather than treating them as ordinary overhead or underground line assets.

3.1.2.8 LARGE AND CONCENTRATED UNDERGROUND CABLE SYSTEMS IN SPECIFIC COMMUNITIES

Although underground cable represents a smaller share of Hydro One's total distribution line length than overhead infrastructure, Hydro One still operates one of the largest underground cable systems in Ontario. The system includes approximately 10,900 circuit-kms of primary underground cable, making Hydro One one of the largest underground cable operators among Ontario distributors by total length, as shown in Figure 7.

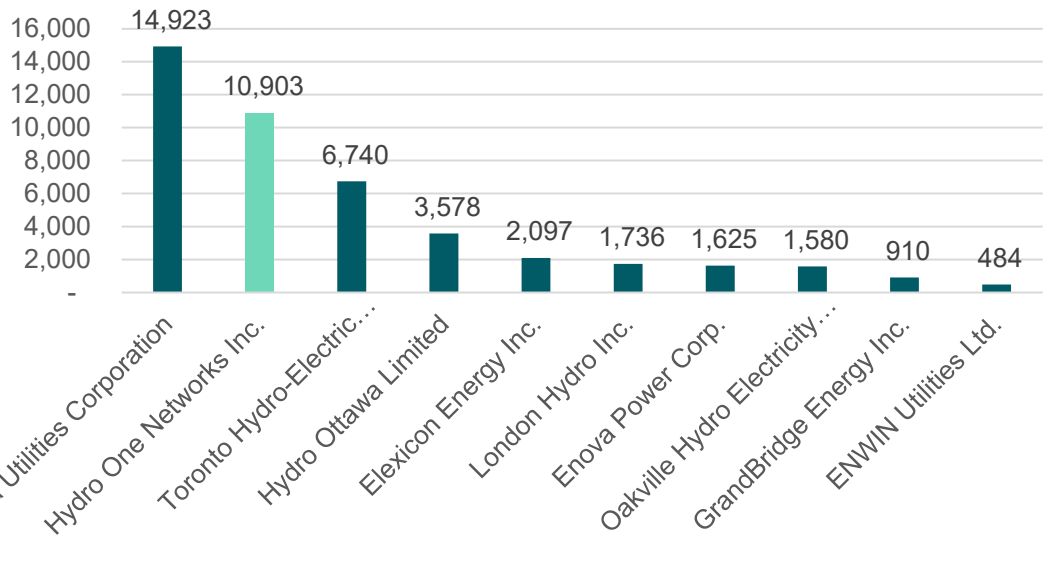


Figure 7: Primary Underground Cable Length - Ten Largest Ontario Distributors[8]

Hydro One's underground cable assets are concentrated in particular urban and suburban residential communities. In those locations, cable failure can cause repeated sustained interruptions, require fault location and excavation, create traffic and property disruption, and be difficult to restore where there is limited back-feed capability.

Hydro One has historically managed much of this cable on a run-to-failure basis. However, as the underground cable population ages and performance issues become more concentrated in specific communities, a targeted planned approach is required to manage cable lifecycle risk. This includes improved data collection through diagnostic testing, prioritization based on condition and performance indicators, and the selection of cost-effective renewal options such as replacement or cable injection where appropriate.

[8] *Calculated by Hydro One using OEB reported 2024 utility data "Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.5.5 Utility Characteristics". The peer group consists of the ten largest Ontario distributors by customer count.*

3.1.2.9 LEGACY VOLTAGE CLASSES, STATION DESIGNS, AND TRANSFER CAPABILITY

As outlined in Tables 3 and 4, Hydro One operates multiple primary distribution voltage classes and station configurations that reflect the historical development of the provincial distribution system and the integration of acquired utilities. The primary distribution voltage classes include 4.16kV, 8.32kV, 12.51kV, 13.8kV, 25kV, 27.6kV and 44kV. This diversity reflects the historical development of the provincial distribution system and the integration of acquired utilities.

Table 3 - List of Station Transformers by Voltage Class

Sys Nom Volts - LV	# of Step-Down DS Transformers
4.16kV	163
8.32kV	502
12.51kV	277
13.80kV	11
25.00kV	52
27.60kV	120

Table 4 - List of Feeder Kilometers by Voltage Class

Voltage	Overhead	Subcable	Underground	Total
2.4/4.16kV	1,576	4	388	1,968
4.8/8.32kV	48,166	335	2,628	51,129
7.2/12.51kV	33,706	3,080	949	37,735
8.0/13.8kV	371	1	206	577
14.4/25.01kV	6,237	570	116	6,923
16.0/27.6kV	14,354	131	3,039	17,523
22.8kV	-	-	-	-
44kV	10,038	24	71	10,133
Total	**114,446**	**4,145**	**7,397**	**125,988**

Tables 3 and 4 show that the 8.32kV and 12.51kV classes account for the largest portions of the system, together representing approximately 88,900km, or about 71% of total distribution line length shown in the table. At the same time, Hydro One continues to

operate material populations of other voltage classes, including 163 step-down distribution-station transformers and approximately 1,968km of line at the legacy low-voltage 4.16kV level.

A diverse voltage and station fleet increases the complexity of standards, protection coordination, voltage regulation, spares, training, work methods, automation, station interfaces, and feeder transfers. It can also limit the ability to substitute equipment or transfer load between adjacent systems during planned and unplanned outages.

The legacy low-voltage systems, including 4kV assets located largely in established communities, are a particular planning consideration. These systems can have limited capacity, greater voltage-drop constraints, fewer practical transfer options, and equipment that is increasingly difficult to standardize or maintain. Where a legacy station or feeder is already constrained or requires material renewal, a like-for-like replacement will preserve these limitations for another asset lifecycle, which generally is 40 years or more. Consolidating to standard system voltages of 8.32kV and above improves feeder capacity, reduces system losses, enables additional feeder ties, and improves operation flexibility.

Where a condition-driven station or line renewal need occurs on a legacy system, Hydro One considers whether like-for-like replacement, voltage conversion, station consolidation, feeder extension or broader system reconfiguration provides the most prudent lifecycle solution. A conversion or reconfiguration can reduce exposure to obsolete equipment, increase capacity, improve protection and transfer capability, and enable automation.

However, it can also require downstream line, transformer, metering and customer work. Hydro One therefore assesses these options case by case, considering asset condition, loading, customer impact, constructability, outage requirements, and the incremental benefits beyond like-for-like renewal.

3.1.2.10 IMPLICATIONS FOR INVESTMENT PLANNING PROCESS

The foregoing characteristics establish the system context for the 2028-2032 DSP. Hydro One's investment plan must sustain a large and geographically dispersed asset base with

low customer density, address local reliability and resiliency issues that may be masked by system averages, meet customer and DER connection obligations, consider the downstream consequences of embedded LDC supply, manage specialized assets such as submarine cables, and evaluate whether legacy systems should be renewed, converted or reconfigured where broader lifecycle benefits are available.

These characteristics are reflected in the investment planning methodology, capital expenditure summary and Investment Summary Documents that follow. They explain why Hydro One's distribution planning must consider not only asset condition and growth needs, but also service territory dispersion, radial supply limitations, weather and vegetation exposure, local community impacts, specialized asset requirements and the long-term cost of maintaining safe and reliable service across Ontario.

These considerations inform the development and assessment of investment candidates. DSP Section 3.7 describes how Hydro One applies these inputs within its investment planning framework, and DSP Section 3.11 provides the program-level and project-level justification for the resulting investments.

3.1.3 INVESTMENT NEEDS AND OBJECTIVES

This section provides an overview of the investment needs and objectives underpinning the 2028–2032 forecast period, which reflect current state of the system and the external factors that are intensifying the demands placed upon it. As noted above, the DSP focused on three investment priorities:

3.1.3.1 MAINTAINING THE GRID

Hydro One's first Distribution Investment Priority is to:

- Maintain the safe and reliable operation of the existing distribution system.

Hydro One operates a large and diverse distribution asset base that requires ongoing inspection, maintenance, refurbishment and replacement, as well as the replacement of assets that fail or are damaged during storms, to continue providing safe and reliable service. 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 (ESL). As these assets continue to deteriorate through age, use and environmental exposure, the volume of assets requiring refurbishment or replacement is increasing. For example, 45% of station transformers are now beyond their ESL and an additional 10% are forecast to reach or exceed ESL by 2032 if no action is taken.

Table 5 summarizes the demographic profile of key distribution asset classes and the extent to which these populations are expected to progress through their ESL during the planning period.

Table 5 - Summary of Distribution Key Assets Demographics

Asset Component	Average Age	ESL	Population Beyond ESL, 2020	Population Beyond ESL, 2025	Population Beyond ESL by 2032, Absent Replacement
Station transformers	43 years (32 - ORZ, 58 - PRZ)	50 years	33%	45% (36% - ORZ, 87% - PRZ)	55% (45% - ORZ, 94% - PRZ)
MUS transformers	35 years	40 years	46%	48%	61%
Poles	43.7 years	60 years	23%	28%	35%
Underground cable	22 years	30 years	Unavailable	30%	43%
Retail Revenue Meters	11.3	15 years	0%	50%	68%

Table 6 shows the population of key assets categorized as poor condition, demonstrating that a material number of key assets are currently in poor condition. These assets are generally addressed through planned refurbishment or replacement programs. Proactive investment helps reduce the likelihood of asset failure and supports improved reliability outcomes by reducing the risk and, for certain asset classes, the duration of customer outages. These impacts can be amplified during severe weather events.

Table 6 - List of Distribution Key Assets in Poor Condition

Asset	% in Poor Condition	Quantity in Poor Condition
Station Transformers	19%	231
Mobile Unit Substations	24%	8
Poles	6%	99,000
Submarine Cable	10%	1,350

Taken together, Table 5 and Table 6 demonstrate both the underlying demographic pressure across Hydro One's asset base and the condition-based renewal needs that already exist today. These needs are expected to increase as the asset population continues to age and deteriorate. For example, Hydro One currently has approximately 99,000 wood poles (or about 6% of the fleet) identified in poor condition. Without investment, the poor condition pole population is forecast to grow to more than 200,000 poles by 2032.

Hydro One also has material populations of station transformers, mobile unit substations, underground and submarine cables and other distribution assets requiring ongoing renewal. In some asset classes, the nature of the need is also changing. For example, acute risks are accumulating as the underground assets serving urban communities begin to deteriorate. The estimated average age of underground cables in 2028 is 25 years, relative to an expected service life of 30 years, and Hydro One estimates that approximately 43% of UG cables will be beyond their expected service life in 2032. There are also approximately 1,800 underground cable defects identified on the distribution system, and the average annual number of interruptions caused by underground cables was 60% higher during 2021-2025 than during 2016-2020. Targeted investment in the underground system is needed to address this challenge and curb the deterioration of performance in key pockets of the system by replacing cables or injecting them to extend their useful life. To address this emerging challenge, Hydro One first plans to collect enhanced data through cable diagnostic testing and use these results to prioritize the renewal investments in a cost-effective manner.

Assets that are in poor condition or operating beyond their expected service life present elevated risks to the distribution system, to the communities the distribution system supplies, and to the crews maintaining the system. Equipment failure remains a material contributor to customer outage duration and, excluding force majeure and loss-of-supply events, accounts for approximately one-third of all customer outage hours or SAIDI as depicted below in Figure 8.

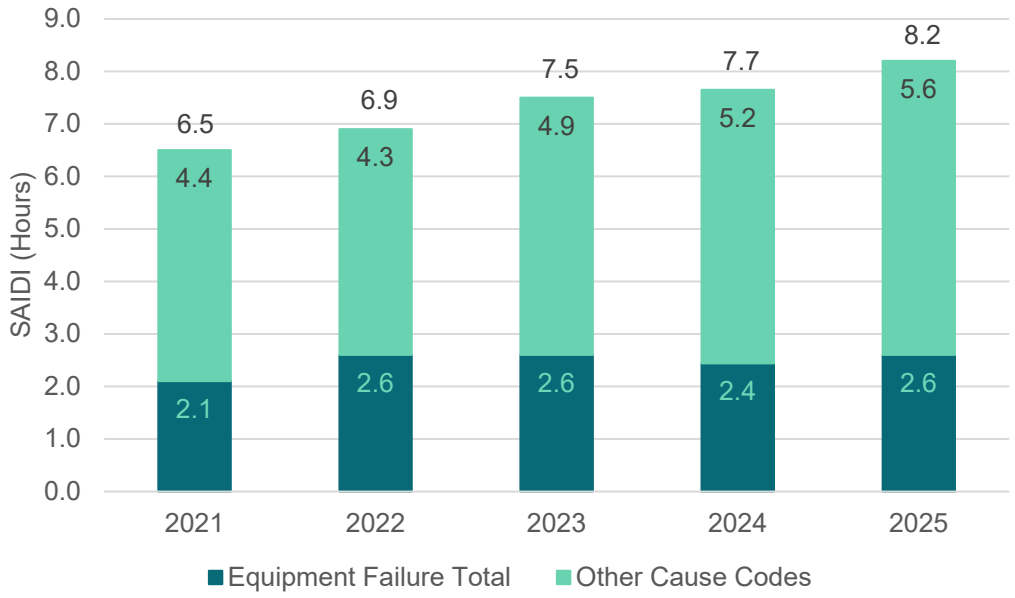


Figure 8: Portion of Annual SAIDI (Excluding Force Majeure and Loss of Supply Events) Caused by Equipment Failure

To ensure safety, it is important to keep equipment well-maintained and functioning properly to prevent any serious failures that could endanger both the public and employees. Environmentally, older equipment presents risks like oil leaks. Furthermore, unforeseen equipment outages affect Hydro One's capacity to carry out planned outages, which may lead to the cancellation or postponement of essential maintenance activities and subsequently increase the risk of further failures.

As the steward of the system for future generations, Hydro One must make thoughtful and gradual investments to maintain and support these critical assets, so they continue to provide safe and reliable power in the next rate period and beyond.

Alongside the natural deterioration of assets as they decline due to age, and environmental exposure, Hydro One faces another challenge in this DSP: between 2023 and 2027, planned investments for asset renewal had to be reprioritized to address demand-driven work and market-driven cost pressures, (see SPF Section 1.8). As described in Sections 3.7 and 3.9, this resulted in less planned condition-based renewal and reliability work than originally forecast in certain programs. Those trade-offs allowed Hydro One to address the more immediate requirements that materialized during the period, but they did not eliminate the underlying lifecycle needs and contributed to the volume of work that must now be managed during the 2028-2032 period.

The asset classes that have been impacted by the reprioritization of work during the current rate period are poles, station transformers, stations switches, MUS Transformers, MUS Structures, and DS Stations (see DSP Section 3.2 for more information about the current state of these assets and planned investments to address their deterioration).

Hydro One must invest in the replacement, refurbishment and restoration of these assets, including the assets that fail or are damaged, to ensure they remain capable of providing safe and reliable power to customers. Those investments are summarized in section 3.1.4.2 below, under the System Renewal category, and further detailed in DSP Section 3.8 and DSP Section 3.11.

Hydro One also uses targeted grid modernization where it improves the effectiveness of maintaining investments and avoids replacing assets on a like-for-like basis when a more prudent lifecycle solution is available. The modernization elements associated with maintaining the grid are focused on improving asset condition monitoring and system visibility, maintaining existing digital infrastructure, and enabling more informed system renewal decisions. For example:

- **AMI 2.0 and Distributed Intelligence and Distribution Automation (DIDA):** The AMI 2.0 meter replacement program sustains core metering and communications capabilities and enables the use of embedded computing, sensing, and storage capabilities within AMI 2.0 meters to support distributed intelligence. This functionality facilitates the assessment of localized operating conditions, including voltage, load, and connectivity, and the provision of actionable information to support planning, operations, and asset management activities.
- **System Monitoring:** Online dissolved gas analysis, thermal monitoring, and related diagnostic tools provide earlier visibility into the condition of selected station assets, supporting planned mitigation of end of life failure risk and reducing reliance on reactive replacement.
- **Creation of Virtual Assets:** LiDAR patrols and satellite imagery are used to establish a baseline digital record of line asset condition, supporting future virtual patrols and asset condition assessments.
- **System Reconfiguration and Hardening**: Where renewal needs are concentrated in climate vulnerable areas, Hydro One considers replacing poor-condition poles with higher-class poles in clusters, addressing the underlying asset need while improving the resiliency of the renewed infrastructure.

3.1.3.2 IMPROVING RELIABILITY AND RESILIENCY

Hydro One's second Distribution Investment Priority is to:

- Reduce outage impacts and improve the distribution system's ability to withstand and recover from increasingly severe operating conditions.

Reliability and resilience are increasingly important outcomes for Hydro One's customers and the provincial economy. As customers become more dependent on the grid for more aspects of their daily work and life, they are in turn more vulnerable to factors such as the intensifying impacts of climate change such as the frequency and severity of storms.

Maintaining distribution assets in acceptable condition is necessary to support reliable service, but asset renewal alone is not sufficient to address the reliability and resiliency

challenges experienced across Hydro One's distribution system. As described in Section 3.1.2, long radial feeders, limited alternate-supply capability, extensive overhead infrastructure, off-road access and vegetation exposure mean that a fault can interrupt all customers downstream of the affected location and that restoration may require lengthy fault location, isolation, access and repair.

These system characteristics create reliability challenges during normal operating conditions and become more consequential during severe-weather events. Hydro One's predominantly overhead distribution system is directly exposed to wind, ice, lightning, falling trees and other weather-related hazards, while long radial supply paths and difficult access can prolong restoration once damage occurs.

System performance trends reinforce the need for action. As shown in Figure 9, over the last five years, Distribution SAIDI increased from 6.5 hours in 2021 to 8.2 hours in 2025, while Distribution SAIFI increased from 2.4 in 2021 to 2.9 in 2025.

Figures 10 and 11 provide further information on the causes of customer interruptions and demonstrate the continuing contribution of equipment failure, vegetation and adverse weather to reliability performance.

Weather-related pressures have further contributed to reliability challenges. In 2025, Hydro One experienced 62 force majeure and storm days, exceeding the 10-year historical average (2015-2024) of 48.4 storm days per year. As discussed in DSP Section 3.7, Hydro One's distribution system now experiences 51.6 force majeure and storm days over the recent five-year period (2020-2024) compared with a ten-year average of 48.4 days, representing a sustained increase relative to historical levels. The increasing frequency and severity of storms have heightened outage exposure and restoration requirements, placing additional pressure on reliability performance and reinforcing the need for continued investments in system resilience.

In addition to a higher frequency of major storms, Hydro One's customers experienced two severe weather events in the last five years: the May 2022 derecho and the March

2025 ice storm, which together cost close to $306M to repair. Storms, along with tree contacts and equipment failures, have the greatest impact on Hydro One Distribution's reliability outcomes. These events highlight the growing operational and financial impacts of severe weather on the distribution system, including increased outage frequency, longer restoration efforts, and higher recovery costs. The experience of recent years demonstrates the need for continued investments in system hardening, vegetation management, and asset renewal to improve network resilience and mitigate the effects of increasingly severe weather events.

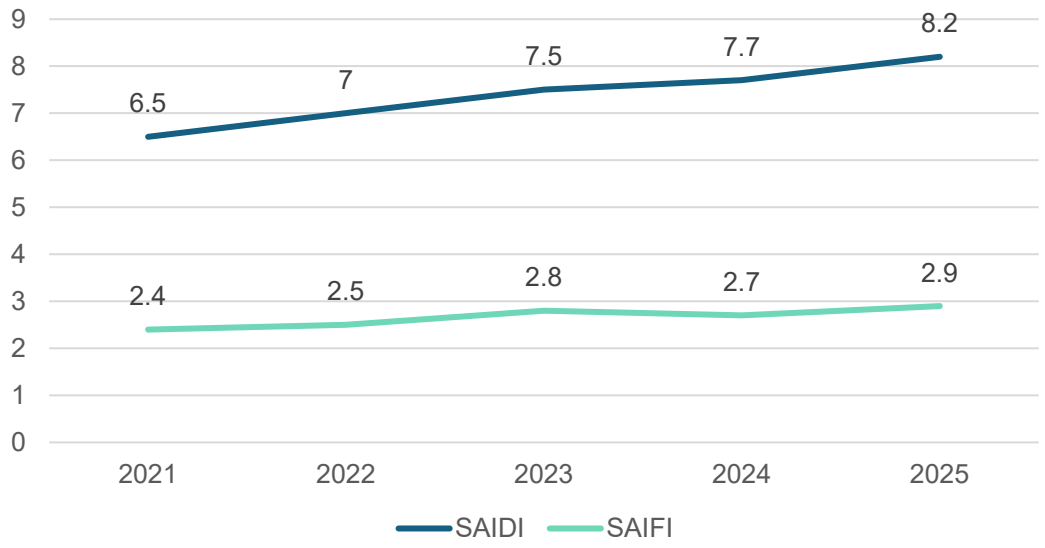


Figure 9: SAIDI and SAIFI from 2021 to 2025

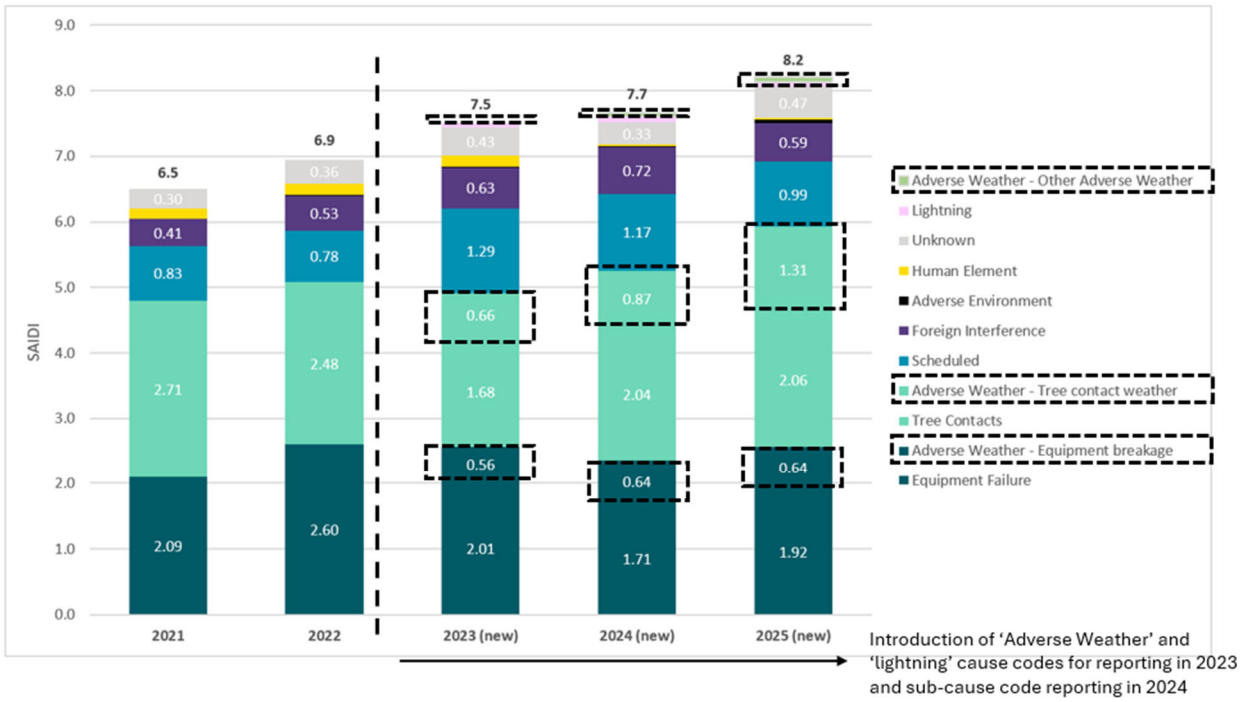


Figure 10: SAIDI Breakdown by Outage Cause Code

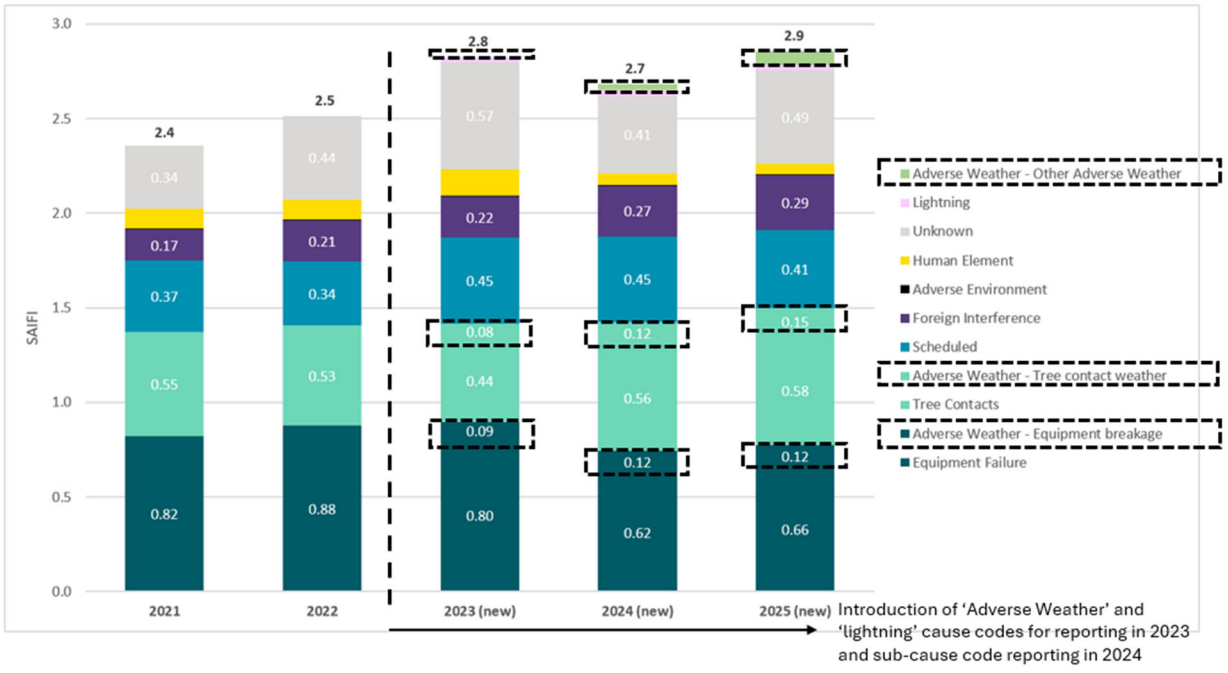


Figure 11: SAIFI Breakdown by Outage Cause Code

To address these challenges, Hydro One has developed a plan to maintain and gradually improve system reliability, reduce restoration times, and proactively mitigate outage risks. The plan considers integrated approaches to renewal, hardening, and automation that deliver increased system-level benefits and value beyond traditional like-for-like replacement. These programs include strengthening or relocating vulnerable infrastructure, improving feeder ties and transfer capability, increasing sectionalization and remote switching, improving fault indication and system visibility, selectively undergrounding high-consequence sections, maintaining strategic spare equipment, or using energy storage where customers or communities have limited other options.

To support the reliability and resiliency priority, Hydro One is improving the configuration, flexibility, visibility, control, and analytical capability needed to reduce outage frequency, shorten restoration times, and target investments to the feeders and assets that drive the greatest customer impact. These investments are enabling capabilities embedded within reliability, resiliency, renewal, and operating programs. Hydro One's grid modernization investments supporting reliability and resiliency include:

- **Feeder ties, remote switching and fault indication:** Reliability Improvement and Distribution Automation investments add tie-line capability, SCADA-enabled switching, and Communication Fault Circuit Indicators (CFCIs) on poor-performing feeders, improving fault location, isolation, transfer capability, and restoration response.
- **AMI 2.0 and DIDA:** AMI 2.0 and the DIDA provide more granular outage, load, voltage, and power quality data that support power quality resolution, end-of-line voltage assessment, and more informed local reliability decisions.
- **Intelligent Grid Platform:** Advanced Distribution Management Systems (ADMS) and modern Outage Management System (OMS) / Distribution Management System (DMS) functionality integrate field-device, SCADA, and AMI data to improve situational awareness, state estimation, fault detection, load-transfer analysis, outage response, and system control.
- **Energy storage:** Battery energy storage provides localized backup supply for customers and communities experiencing poor reliability where conventional wires solutions are not practical or cost-effective.

- **System Reconfiguration and Hardening:** Voltage consolidation, selective undergrounding, and targeted rebuilding or relocation of vulnerable line sections address system configuration and vulnerabilities while delivering broader reliability and resiliency benefits than conventional asset renewal.

3.1.3.3 MEETING ONTARIO'S GROWING DEMAND

Hydro One's third Distribution Investment Priority is to:

- Enable customer growth, electrification, and economic development while continuing to meet its obligations to connect customers safely and reliably.

Access to electricity is essential for enabling provincial growth and economic development, and also helps customers adopt new technologies, such as electric vehicles. However, due to accelerated growth experienced in recent years, many parts of Hydro One's distribution system are reaching or surpassing their planning limits and require upgrades to safely and reliably meet customers' growing electricity requirements. These challenges are illustrated in Figures 12 and 13 below which show the current and forecasted utilization of Hydro One's transformers and feeders across the four regions of its system.

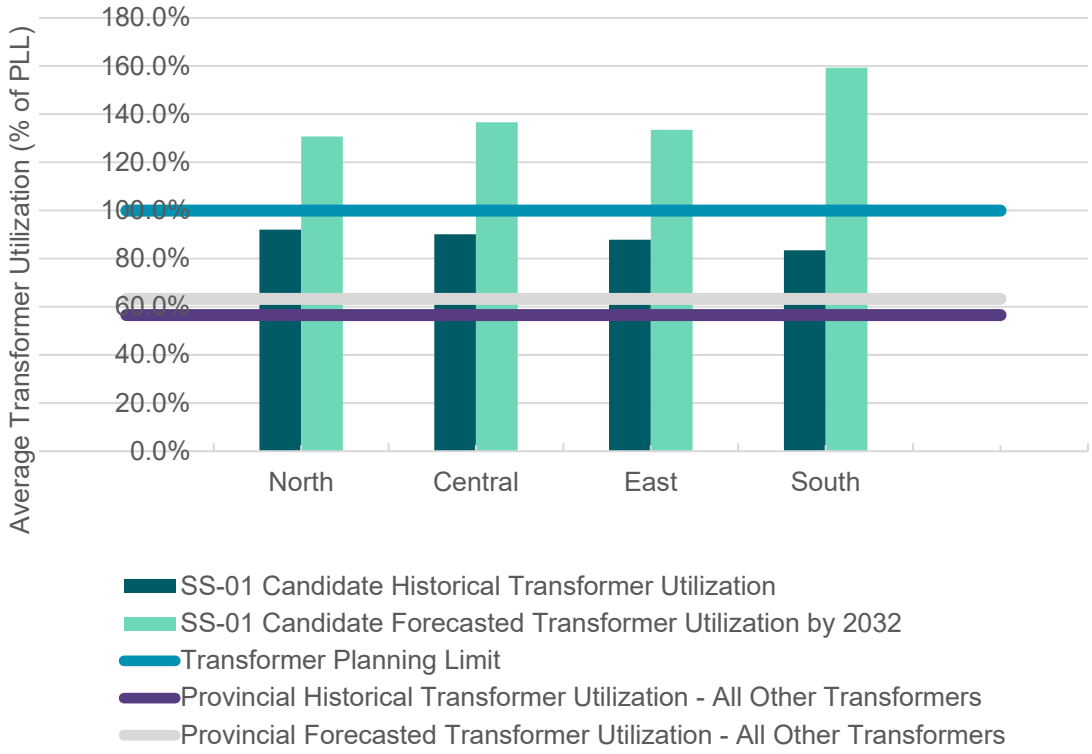


Figure 12: Station Transformer Utilization for Upgrades Driven by Load Growth Investments

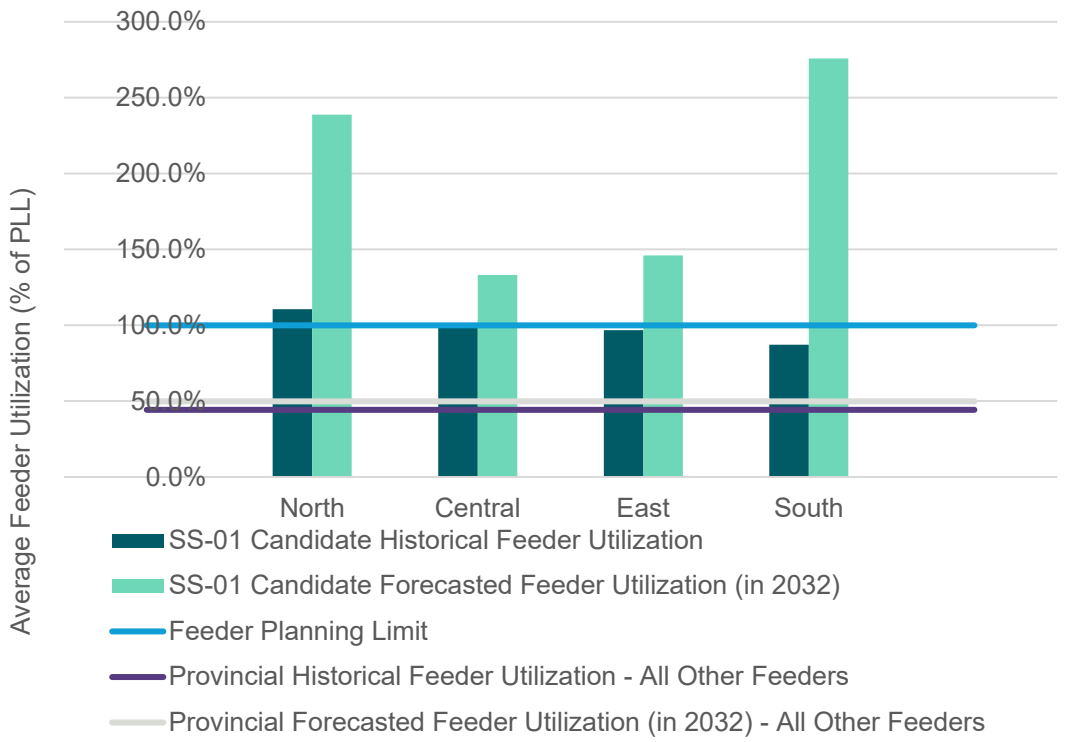


Figure 13: Feeder Utilization for Upgrades Driven by Load Growth Investments

As demand continues to increase, Hydro One must plan and expand its distribution system to address these current constraints and meet future needs, in accordance with its obligation under section 3.3 of the Distribution System Code to plan for reasonable load growth. This includes investment in new stations, feeders, and other system upgrades, as well as contributions for upstream transmission investments that are necessary to increase supply to the local grid.

Hydro One must also connect new load and generation customers, and enable third-party infrastructure work, to support provincial growth, infrastructure development and customer requirements. Over the 2028–2032 planning period, Hydro One expects to connect

approximately 93,500 new customers and perform service upgrades for approximately 38,900 customers[9].

In the 2028-2032 period, Hydro One also expects that customers in its service territory will install over 1,700 small to large-sized and over 8,200 residential distributed energy resources (DER) to participate in various IESO programs and to generate their own power and manage their electricity consumption and demand (see DSP Section 3.4). These projections are informed by the IESO's Distributed Energy Resources (DER) Potential Study prepared by Dunsky Energy + Climate Advisors (the "Dunsky Study") and are driven in part by provincial programs and initiatives, such as Net Metering and Save on Energy, which provide incentives for customers to install solar photovoltaic (PV) distributed generation and battery energy storage systems (BESS).

Consistent with OEB and provincial policy objectives, this DSP includes investments to enable customers to connect DERs to feeders that are currently restricted for micro-embedded generation. These investments are necessary to remove system barriers to DER adoption and facilitate broader customer participation in distributed energy resources, particularly for low-volume consumers who would not otherwise be able to bear the cost of the system modifications required to connect to constrained feeders.

Hydro One intends to utilize local non-wires solutions to reduce the necessity for traditional capacity investments across 16 projects, in addition to one project deferral that is ongoing. This approach is expected to defer approximately $103M – representing about 6.9% of load growth investments – from the 2028-2032 investment plan. This inaugural non-wires approach will allow Hydro One to implement cost-effective innovative solutions consistent with the OEB's NWS Guideline for Electricity Distributors and Benefit-Cost Analysis Framework for Addressing Electricity System Needs.

[9] The connection and service upgrade volumes exclude Orillia RZ and Peterborough RZ from 2028 to 2030 and include them for 2031 and 2032. Total volumes for Hydro One, Orillia RZ, and Peterborough RZ are provided in DSP Section 3.11, D-SA-02.

To support growth and electrification, Hydro One is improving its ability to identify constraints, monitor loading, enable DER connections, and use non-wires solutions where they are cost-effective. These investments are not a substitute for required station and feeder capacity, but they improve the information and control needed to plan, operate, and defer traditional infrastructure prudently where feasible. Hydro One's growth-related grid modernization investments are focused on the following capabilities:

- **Real-Time Distribution Station and Feeder Monitoring:** Provides continuous, real-time visibility of voltage, current loading, and direction of power flow at targeted higher-utilization stations and feeders, improving the system information available to support capacity planning and system operations.
- **AMI 2.0 and DIDA:** Provides more granular customer, service-transformer, voltage, and load information, improving the visibility needed for electrification planning and localized capacity assessment.
- **DER Hosting Capacity:** Removes identified feeder constraints for DER connections and may include monitoring, protection, control, and system modifications required to connect DERs safely and reliably.
- **Intelligent Grid Platform:** ADMS and future Distributed Energy Resource Management (DERMS) capability will integrate system, field-device, and AMI data to support state estimation, non-wires screening, DER and flexibility management, load transfers, and active distribution-system operations.

3.1.4 CAPITAL EXPENDITURE PLAN SUMMARY

3.1.4.1 CURRENT RATE TERM: 2023-2027 INVESTMENTS

As described in DSP Section 3.9, Hydro One has faced incremental demands on its capital work program necessitating reprioritization of work to meet legal obligations and address critical asset and operational requirements. These factors included rising system access requirements to serve growing customer demand, as shown in Table 7 below, and rising cost pressures as outlined in SPF Section 1.8.

Table 7 - 2023-2027 Plan versus 2023-2027 Actual ($M) by OEB Category

OEB Category	2023–2027 Plan[10] ($M)	2023–2027 Actual / Forecast ($M)	Variance
System Access	1,183.1	1,707.4	44%
System Renewal (Excl. AMI 2.0)	1,408.0	1,512.2	7%
AMI2.0	581.0	546.9	-6%
System Service	920.4	1,038.7	13%
Total	**4,092.5**	**4,805.1**	**17%**

System Access

The variance in this category is driven by higher than forecast customer and third-party driven work volumes, together with a greater number of large and complex connection projects requiring more extensive design and construction effort. New Load Connections, Service Upgrades and Service Cancellations (DSP Section 3.11, D-SA-02, which is the largest program in this category) increased by 54% from $834.6M to $1,292.4M. Joint Use and Relocation work was also affected by higher externally driven work volumes, third-party requirements, and project-specific complexity. In addition, System Access expenditures were affected by broader market cost pressures including material and service cost pressures relative to the assumptions underpinning the approved plan, as discussed in SPF Section 1.8.

System Renewal

The increase in this category is driven largely by storm and trouble response and failure driven station replacements, including mandated PCB equipment replacement requirements. Distribution Lines Trouble Call and Storm Damage Response (DSP Section 3.11, D-SR-05, which is the largest program in this category) increased from $580.6M to $972.3M due in large part to increasing storm frequency and severity, including the 2025

[10] The variances described in this Exhibit are relative to Hydro One's December 2022 capital expenditure plan, which reflects the OEB-approved capital expenditures established through the Settlement Proposal in Hydro One's 2023-2027 Distribution Rates application (EB-2021-0110). In its November 29, 2022 Decision and Order, the OEB approved the capital expenditure and in-service envelopes set out in the Settlement Proposal. In December 2022, Hydro One allocated these approved envelopes to individual programs and projects for each year of the rate period. These allocations represent the basis for the variance comparisons.

March ice storm. The increase was partially offset by reprioritization of planned work in programs such as Pole Replacement and Distribution Station Renewal.

AMI2.0

The AMI 2.0 program has advanced since the 2023-2027 plan, progressing through critical pre-deployment, Head End System implementation, meter and network pilot, mass meter and network deployment commencement, and Distributed Intelligence pilot phases while adapting to systems integration complexity and solution readiness challenges. Of the approximately 1.4M meters to be replaced across the full AMI 2.0 program, approximately 838,000 meters are forecast to be installed in the 2023-2027 period, representing an expected accomplishment variance of 422,000 meters relative to the 2023-2027 plan. Similarly, approximately 9,000 communication network devices are forecast to be installed, compared to approximately 11,000 originally planned for the period. Hydro One now forecasts completion of meter and network device installation in 2029, one year later than originally planned, with a total project cost estimate of $799.4M, which remains $47.3M below the upper bound of the inflation-adjusted estimate of $846.7M provided in the last distribution application (EB-2021-0110). Project costs for the 2023-2027 period are forecast to be approximately $546.9M, $34.1M below the 2023-2027 plan amount of $581.0M, while In-Service Additions are forecast at $499.3M, approximately $81.7M below the amounts settled in EB-2021-0110. A comprehensive description of the AMI 2.0 investment is provided in DSP Section 3.11, D-SR-12.

System Service

The upward pressure within the category arose from programs addressing emerging load growth requirements, power quality and safety risks due to stray voltages. System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01, the largest program in this category) increased from $465.7M to $666.8M and delivered 32% more material investments relative to the plan. To meet customer needs, Hydro One completed more demand-driven load growth upgrades, earlier station and feeder reinforcements, and larger system modifications, in addition to more complex power quality and stray voltage interventions, than originally planned. These increases were partially moderated by lower expenditures in certain reliability and resiliency programs, such as investments in grid-

scale and residential Battery Energy Storage System, as Hydro One reprioritized work to manage within the overall capital envelope.

As noted above and further discussed in DSP Section 3.9, several areas of planned investment for the 2023-2027 period have been reprioritized in response to the demand-driven and cost pressure challenges that Hydro One experience in the current rate period. Although these trade-offs have been manageable in the near-term, they cannot be maintained in the future without compromising safety, reliability and grid access. Incremental system renewal and capacity-related investments are needed in the 2028–2032 plan to address accumulated asset and performance risks, safeguard customer service quality levels, and preserve long-term system outcomes for future generations. Hydro One responded to affordability concerns by reprioritizing, re-pacing, and reducing investments where prudent; however, further deferral of necessary renewal, reliability and capacity investments would increase system risk and long-term outcomes.

3.1.4.2 FUTURE RATE PERIOD: 2028–2032 INVESTMENTS

In the 2028-2032 planning period, Hydro One plans to invest $10,863.3M in its distribution system. Of this, $8,835.4M, or approximately 81%, is allocated to System Access, System Renewal, or System Service investments, which are described in this DSP. The remaining $2,027.9M is allocated to General Plant investments and is described in the General System Plan.

Table 8 shows the annual and total capital investments planned for the 2028-2032 planning period, by OEB category, and Figure 14 below shows historical and forecast expenditures for the 2023-2027 period and proposed expenditures for the 2028-2032 period.

Table 8 - Proposed 2028 – 2032 Investment Plan by OEB Category

OEB Investment Category	Forecasting Period ($M)						
	2028	2029	2030	2031	2032	Total	% of Total
System Access	549.6	406.8	416.0	431.4	445.1	2,248.9	20.7%
System Renewal	630.8	711.9	823.4	806.6	852.3	3,825.1	35.2%
System Service	405.2	497.1	708.4	627.3	523.4	2,761.3	25.4%
General Plant	342.1	311.2	342.2	583.3	449.0	2,027.9	18.7%
Total	**1,927.8**	**1,927.0**	**2,290.1**	**2,448.6**	**2,269.9**	**10,863.3**	**100.0%**

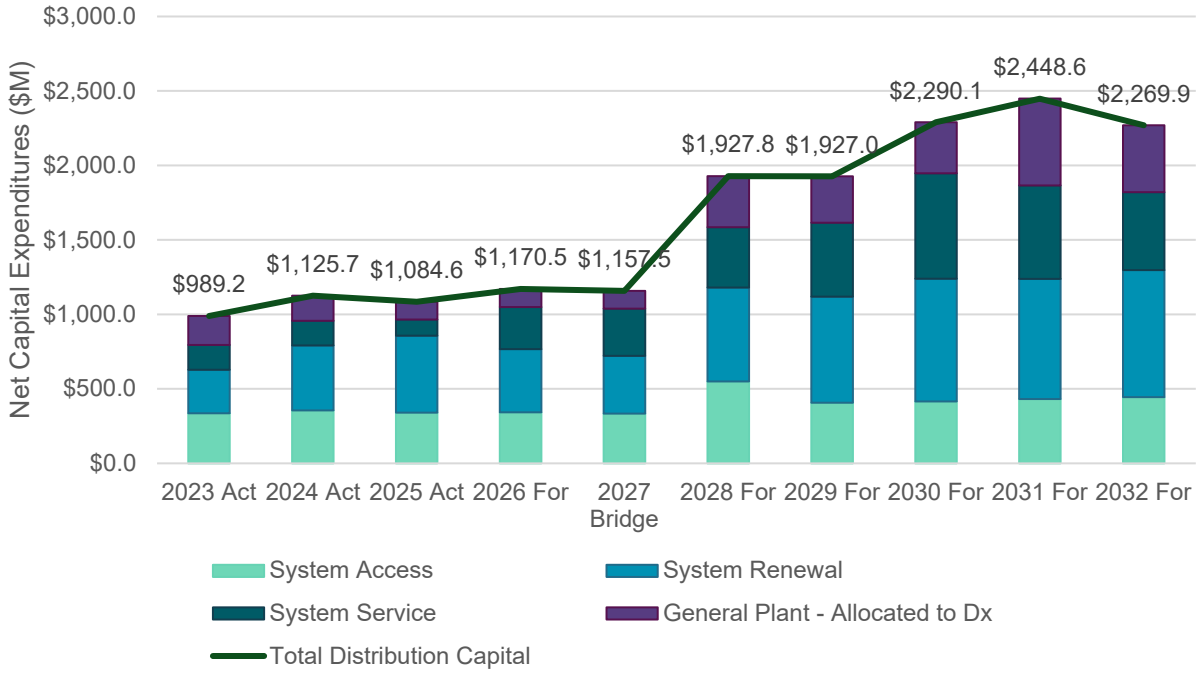


Figure 14: Historical and Forecast Capital Expenditures

The proposed portfolio reflects a material change in both the scale and composition of Hydro One's capital plan relative to the 2023-2027 period. This change is driven by identifiable system needs, including continued mandatory and customer-driven work in System Access; asset condition, safety, reliability, restoration, and resiliency needs in System Renewal; and increased capacity, reliability, resiliency, DER integration,

monitoring, and operational capability requirements in System Service. While broader cost pressures remain relevant, the proposed plan is primarily driven by incremental work requirements in each of the underlying investment categories. The final portfolio reflects the pacing and prioritization of those needs in consideration of affordability, customer feedback and execution capability.

In addition, Hydro One must invest strategically to address emerging challenges and evolving requirements across several new net programs proposed in the 2028-2032 DSP. This includes $1,411.2M in investments in new initiatives outlined below:

- Expanded Pole Sustainment Program (DSP Section 3.11, D-SR-07) replaces poor condition poles with poles of a higher class in a clustered manner to improve system resiliency against force majeure events.
- Underground Cable Replacement and Rejuvenation Program (DSP Section 3.11, D-SR-15) replaces or rejuvenates underground cable in five focus areas experiencing poor reliability due to aging and poor condition assets.
- Voltage Consolidation Program (DSP Section 3.11, D-SR-17) involves upgrading poor condition non-standard 4kV stations and lines assets with standardized 8.32kV or higher assets, to support higher load carrying capability, improved feeder voltage performance, stronger feeder ties for operational flexibility and to reduce outage duration for customers.
- Selective Undergrounding Program (DSP Section 3.11, D-SR-14) buries sections of feeders with dense vegetation and poor condition poles to eliminate tree-caused outages and improve reliability.
- DER Hosting Capacity (DSP Section 3.11, D-SS-07) involves system upgrades to approximately 190 feeders to increase DER hosting capacity on these feeders.
- Distribution Spare Transformer Purchase Program (DSP Section 3.11, D-SR-13) procures strategic spare transformer inventory for distributing and regulating stations to enable timely failed asset replacement and mitigate supply chain constraints.
- System Monitoring (DSP Section 3.11, D-SS-08) monitors poor condition transformer stations to enable planned mitigation and minimize unplanned outages.

- Creation of Virtual Assets (DSP Section 3.11, D-SR-16) establishes baseline lines asset condition digital dataset from LiDAR patrols and satellite imagery. This will enable future asset condition updates through virtual patrols.
- Intelligent Grid Platform (DSP Section 3.11, D-SS-09) adds ADMS capabilities to collectively increase system visibility, enhance operational control, enable advanced analytics and automation, and support cost-effective integration and management of DERs.
- Real Time Distribution Station and Feeder Monitoring Program (DSP Section 3.11, D-SS-10) provides continuous, real-time visibility of voltage, current loading, and direction of power flow at targeted higher-utilization stations and feeders to improve system visibility.

The sections that follow provide an overview of the proposed investments in each of the OEB categories.

System Access

System Access investments are mandatory expenditures that are driven by statutory, regulatory, or other obligations that Hydro One has to provide access to the distribution system. Primarily, these investments relate to customers' connection to the grid (including metering sustainment) and third-party enablement, such as the relocation of system assets to accommodate municipal infrastructure development and facilitating the buildout of broadband per statutory requirements. To address these obligations, Hydro One plans to invest in five System Access programs over the 2028–2032 rate period as summarized in Table 9 below and further detailed in DSP Section 3.8 and DSP Section 3.11.

System Access investments represent approximately 21% of the total capital portfolio in the forecast period and total $2,248.9M over 2028–2032, an increase of $541.5M, or 32%, from the 2023–2027 historical period. The proposed increase enables Hydro One to continue to meet mandatory obligations to provide access to the distribution system (including new and upgraded load connections, service cancellations, DER connections) and to complete third-party driven joint use and relocation and broadband-related access work.

The largest driver of the increase is the New Load Connections, Service Upgrades and Service Cancellations (DSP Section 3.11, D-SA-02) program due to higher customer-driven work volumes, greater average scope as required to accommodate residential electrification-related load such as EV chargers and heat pumps, and broader market-wide cost pressures discussed in SPF Section 1.8.

The System Access increase is also attributable to continued joint-use and relocation requirements driven by municipal, road authority, telecommunications, and other third-party infrastructure activity, in addition to broadband-related make-ready work which is legislatively required to enable third-party fibre attachments.

Table 9 - System Access Investments ($M)

Program	2028-2032 Total	Investment Priority	Description
D-SA-01 Joint Use and Relocations	$263.9	Meet Ontario's Growing Demand	Completes distribution modifications and relocations required to accommodate municipal, transportation, telecommunications, and other third-party infrastructure activities.
D-SA-02 New Load Connections, Service Upgrades, and Service Cancellations	$1,703.3	Meet Ontario's Growing Demand	Connects new customers, upgrades existing services, and removes cancelled services in response to customer-driven demand and electrification.
D-SA-03 Customer Demand Distributed Energy Resources	$49.7	Meet Ontario's Growing Demand	Connects customer-driven DER projects and completes associated system modifications and upgrades required for safe and reliable system integration.
D-SA-04 Metering Sustainment	$81.9	Maintain the Grid	Maintains retail and wholesale metering assets, communications network equipment, and metering capabilities to support accurate billing, customer service, and regulatory compliance.
D-SA-05 Broadband	$150.1	Meet Ontario's Growing Demand	Completes distribution system modifications and access-related work required to accommodate broadband infrastructure development.

Notes: All figures are in nominal net dollars.

System Renewal

Over the 2028–2032 period, System Renewal investments are critical to address the growing population of distribution assets that are aging and in poor condition. These assets must be renewed in a paced manner to manage safety, environmental and reliability risks to the communities served by the distribution system. To mitigate these risks, Hydro One plans to invest in 15 System Renewal programs over the 2028–2032 rate period as summarized in the table below and further detailed in DSP Section 3.8 and the Investment Summary Documents (ISD) in DSP Section 3.11. These investments are largely underpinned by asset condition assessments (see DSP Section 3.2) and are

prioritized based on Risk Spend Efficiency to ensure the highest-risk assets are addressed first (see DSP Section 3.7).

System Renewal investments represent approximately 35% of the total capital portfolio in the forecast period and total $3,825.1M over 2028–2032, an increase of $1,766.0M, or 86%, from the 2023–2027 historical period. This increase is driven primarily by a larger volume and broader scope of planned renewal work required to address poor-condition, aging, damaged, exposed, obsolete, and vulnerable assets across Hydro One's distribution system, following a 2023–2027 period in which available capital was directed to mandatory, safety, reliability, compliance, and customer-driven requirements within the approved capital envelope.

On a work-volume basis, the forecast includes materially higher planned activity in several major renewal programs, including:

- Approximately 54,500 pole replacements, 31,500 pole refurbishments, and 460,000 test-and-treat activities compared with approximately 8,600 pole replacements, 8,700 refurbishments, and 235,000 test-and-treat activities during 2023–2027, and
- 81 station renewal investments compared with eight material investments completed during 2023-2027.

The forecast also reflects a broader cable and line renewal program, including approximately 1,350 identified damaged or exposed submarine cables plus a further 1,900 expected units identified through inspections, compared with approximately 540 submarine cables addressed in 2023–2027, and 31 material Distribution Lines Sustainment investments compared with 10 completed or forecast over 2023–2027 as summarized in Table 10 below. In addition, the 2028–2032 plan introduces dedicated programs for selective undergrounding and underground cable renewal, including work to convert selection sections of existing overhead line to underground construction to address vulnerable infrastructure and to replace approximately 250 km of deteriorated underground cable and rejuvenate approximately 500 km through cable injection, reflecting a shift from reactive response to a more planned renewal approach. Together,

these increased work volumes and new planned renewal programs are intended to reduce exposure to unplanned failures, improve restoration capability, address safety and reliability risk, and lower reliance on reactive or emergent replacement work over the forecast period.

Table 10 - System Renewal Investments ($M)

Program	2028-2032 Total	Investment Priority	Description
D-SR-01 Distribution Stations Demand Capital	$71.5	Maintain the Grid	Replaces failed or failing station assets and addresses station equipment needs required to maintain safe and reliable station operation.
D-SR-02 Mobile Unit Substation Program	$65.6	Maintain the Grid	Replaces and expands the MUS fleet to support restoration, emergency response, and planned station work while minimizing customer outages.
D-SR-03 Distribution Station Planned Component Replacement	$22.3	Maintain the Grid	Replaces deteriorated station components, including MUS structures, switches, and reclosers, to maintain safe and reliable station operation.
D-SR-04 Distribution Station Renewal	$329.1	Maintain the Grid	Renews distribution stations through planned replacement, rebuilding, decommissioning, and bundled renewal work to address deteriorated and end of life components.
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response	$983.4	Maintain the Grid	Replaces and restores failed or damaged distribution assets through trouble-call and storm-response activities to restore safe and reliable service.
D-SR-07 Pole Sustainment Program	$919.3	Maintain the Grid	Addresses poor-condition poles through test-and-treat, refurbishment, replacement and targeted hardening to mitigate safety and reliability risks and improve resiliency to severe weather.
D-SR-08 Distribution Lines Minor Component Replacement	$131.7	Maintain the Grid	Replaces deteriorated or obsolete line components such as crossarms, substandard transformers, communicating fault circuit indicators, sentinel lights, and related equipment to reduce equipment failure risk.

Program	2028-2032 Total	Investment Priority	Description
D-SR-09 Submarine Cable Replacement Program	$126.3	Maintain the Grid	Replaces damaged, exposed or deteriorated submarine cables to mitigate safety and reliability risk.
D-SR-10 Distribution Lines Sustainment Initiatives	$209.0	Reliability and Resiliency	Rebuilds and relocates line sections with a high concentration of poor-condition assets to maintain or improve reliability and restoration access.
D-SR-12 Advanced Metering Infrastructure 2.0 (incl. DIDA)	$279.7	Maintain the Grid	Replaces legacy smart meters with next-generation metering and communications capability and incorporates distributed intelligence and distribution automation functionality to support improved data granularity, system visibility, outage response, customer insights, DER-related use cases, and load planning.
D-SR-13 Distribution Spare Transformer Purchase Program	$57.5	Reliability and Resiliency	Procures spare distribution station transformers to ensure spare-fleet adequacy, support timely replacement of failed or failing units and reduces restoration risk.
D-SR-14 Selective Underground	$100.3	Reliability and Resiliency	Undergrounds targeted sections of vulnerable overhead infrastructure to reduce severe-weather exposure and improve reliability and resiliency.
D-SR-15 Underground Cable Replacement Program	$337.5	Maintain the Grid	Replaces and rejuvenates aging and poor-performing underground cables to improve asset condition and reduce cable-related outages.
D-SR-16 Creation of Virtual Assets	$38.4	Maintain the Grid	Creates a digital library using LiDAR and satellite imagery to support future virtual inspections and asset-condition assessment.
D-SR-17 Voltage Consolidation	$153.6	Reliability and Resiliency	Converts end of life transformer stations and associated feeders from 4.16kV to a higher standard voltage to improve operational flexibility, system resiliency, and mitigate risks associated with non-standard infrastructure.

Notes: All figures are in nominal net dollars.

System Service

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 service needs and requirements, particularly with respect to system capacity, reliability and resiliency, and DER enablement and integration. To enable these critical customer outcomes, Hydro One plans to invest in ten System Service programs over the 2028–2032 rate period as summarized in Table 11 below and further detailed in DSP Section 3.8 and the ISDs in DSP Section 3.11.

For the 2028–2032 forecast period, System Service expenditures total approximately $2,761.3M, compared to approximately $1,038.7M over the 2023–2027 period, representing an increase of approximately $1,722.6M, or approximately 166%. This increase is driven primarily by higher volumes of load-growth investments, including upgrades to stations, feeders and downstream equipment to address load growth and system constraints, as well as targeted investments in reliability improvements, distribution automation and sectionalization, DER hosting capacity, system monitoring and intelligent-grid capabilities. In addition, the forecast reflects a significant scale-up in Energy Storage Solutions, from one grid-scale battery project and approximately 360 residential battery installations in the 2023–2027 period to 25 grid-scale battery energy storage system projects and approximately 5,400 residential battery installations in 2028–2032.

Table 11 - System Service Investments ($M)

Program	2028-2032 Total	Investment Priority	Description
D-SS-01 System Upgrades Driven by Load Growth	$1,377.4	Meet Ontario's Growing Demand	Constructs and upgrades stations and feeders, and other system infrastructure to relieve regional capacity, thermal, voltage, and operating constraints associated with load growth.
D-SS-02 Reliability Improvements	$84.5	Reliability and Resiliency	Constructs and enhances feeder ties and reduces feeder exposure to improve reliability, load-transfer capability, and alternate supply arrangements.
D-SS-03 Demand System Modifications	$117.0	Meet Ontario's Growing Demand	Completes customer and demand-driven system modifications and upgrades to address localized capacity, power quality, and equipment limitations.
D-SS-04 Energy Storage Solutions	$691.3	Reliability and Resiliency	Deploys grid-scale and residential battery solutions to improve reliability outcomes for vulnerable customers, First Nations communities, and rural or remote areas with poor reliability performance.
D-SS-05 Distribution Automation and Sectionalization Program	$270.8	Reliability and Resiliency	Installs remotely operable SCADA-enabled devices on targeted feeders to reduce outage duration and improve monitoring, switching, and restoration capabilities.
D-SS-06 Power Quality and Stray Voltage	$37.4	Reliability and Resiliency	Addresses customer-specific power quality and stray voltage issues to maintain safe and acceptable system performance.
D-SS-07 DER Hosting Capacity	$71.4	Meet Ontario's Growing Demand	Removes feeder constraints that limit micro-embedded generation connections to improve hosting capacity and support the safe and reliable integration of distributed resources.
D-SS-08 System Monitoring	$51.2	Maintaining the Grid	Deploys online continuous asset-condition monitoring on at-risk stations transformers to enable earlier identification of deterioration and corrective action, and reduce the risk of unplanned failures and customer interruptions.

Program	2028-2032 Total	Investment Priority	Description
D-SS-09 Intelligent Grid Platform	$31.7	Meet Ontario's Growing Demand	Establishes the technology and operational capabilities required to improve real-time visibility, system control, incident management, and DER integration.
D-SS-10 Real Time Distribution and Feeder Monitoring Program	$27.7	Meet Ontario's Growing Demand	Installs monitoring devices on station transformers and feeders to improve real-time loading visibility and support system planning and operation.

Notes: All figures are in nominal net dollars.

3.1.5 THE DSP IS REASONABLE AND APPROPRIATE

The DSP is the product of a thorough investment planning process. It reflects customer needs and preferences, includes third-party benchmarking and analysis, and promotes OEB's RRF outcomes. Hydro One has established the capability, processes, and governance to deliver these investments as planned, and has proposed performance measures aligned with the expected outcomes of plan. Each of these considerations is summarized in more detail below.

3.1.5.1 INVESTMENT PLANNING PROCESS

Hydro One established the DSP through the integrated planning framework described in DSP Section 3.7, which combines asset management and investment planning processes to identify, select, prioritize, optimize, and pace investments over the planning period.

The investment planning process begins with a current-state assessment of the distribution system, including asset condition, asset criticality, utilization, performance, customer needs, system needs, regional planning inputs, external requirements, regulatory obligations, and other planning considerations. Based on this assessment, Hydro One develops candidate investments that respond to identified asset, customer, system, and external requirements, including mandatory connection and service obligations, renewal of deteriorated assets, reliability and resiliency needs, load growth, electrification, DER integration, and emerging grid capability requirements. These investments are then assessed and prioritized based on total risk mitigation, risk-spend

efficiency, contribution to desired outcomes, and alignment with Hydro One's Distribution investment priorities: maintaining the grid, improving reliability and resiliency, and meeting Ontario's growing demand.

For each investment candidate, Hydro One assesses risk across applicable safety, reliability, and environmental categories by considering the probability and consequence of relevant events, using historical data, condition information, performance information, and operational experience to the extent available. The process is supplemented by a flagging mechanism that accounts for special considerations, including compliance-driven investments (see section 3.1.5.2 below for more details) and investments that respond to specific customer priorities (see section 3.1.5.3 below for more details). Risk scores are normalized by estimated investment cost to rank investments by risk mitigated per dollar, or Risk Spend Efficiency, while risks deemed unacceptable are addressed through inclusion of the investments required to reduce those risks to an acceptable level.

Hydro One then uses calibration, challenge, and engagement processes to refine the portfolio and confirm that the proposed plan appropriately balances risk reduction, customer outcomes, affordability, execution feasibility, and overall portfolio value. Enterprise engagement further incorporates execution considerations, including resourcing, material availability, updated cost estimates, schedules, and scope, so that the plan is practical and deliverable over the 2028–2032 period.

Customer engagement is also integrated into the investment planning process. As further described below in section 3.1.5.3, customer priorities informed investment strategies, candidate investments, and pacing decisions, including priorities related to affordability, reliability, resilience, timely connections, growth, and system visibility. Hydro One considered this feedback together with system needs, asset condition, risk mitigation considerations, regulatory obligations, and cost impacts in finalizing the DSP.

The resulting DSP is a balanced portfolio of investments that has been prioritized and paced to address the most significant asset, safety, reliability, resiliency, compliance,

customer and growth-related needs while managing customer bill impacts and execution capability.

The DSP reflects Hydro One's determination as to which investments should proceed in the 2028–2032 period, which needs and objectives can be managed over a longer horizon to balance customer affordability, and where alternative approaches, including non-wires solutions, may provide cost-effective long-term system benefits. The plan addresses the highest priority needs over the 2028 to 2032 rate period recognizing that not every system need can or should be addressed at once.

Through this process, Hydro One has developed a DSP that aligns with its strategic priorities, customer needs and preferences, mandated obligations, and the OEB's RRF outcomes of customer focus, operational effectiveness, public policy responsiveness, and financial performance.

3.1.5.2 LEGISLATIVE AND REGULATORY OBLIGATIONS

Hydro One's distribution capital plan for 2028–2032 is driven by a layered framework of legislative and regulatory mandates that collectively account for approximately 45% of the utility's total expenditure, as shown in DSP Section 3.7. For example, T*he Building Broadband Faster Act, 2021* introduced an entirely new $150.1M program requiring distribution system modifications to enable third-party broadband access. Federal metering legislation, the OEB's Distribution System Code, and IESO Market Rules drive the $81.9M Metering Sustainment program to ensure accurate billing across approximately 1.5M retail meters. Further obligations under Hydro One's Distribution License, the Electricity Act, the Public Service Works on Highways Act, and Ontario Regulation 22/04 require the utility to connect customers on demand, accommodate municipal relocations, and maintain safe operations.

3.1.5.3 CUSTOMER ENGAGEMENT

As noted in SPF Section 1.6, customer engagement feedback directly informed and shaped the development of the System Plans, including the GSP. In 2024 and 2025, Hydro One conducted a comprehensive, two-phase customer engagement exercise in

conjunction with the planning process. The engagement process incorporated feedback from a broad cross-section of Hydro One's customers, using multiple engagement methods to capture input from different customer segments.

The first phase occurred early in the planning process and focused on identifying customers' general needs, priorities, and desired outcomes. The second phase occurred after preliminary investment options had been developed and focused on gathering customer perspectives on trade-offs between different investment priorities. The results of this engagement informed Hydro One's understanding of customer outcome preferences, including priorities related to reliability, affordability, and resilience.

Customer priorities identified in Phase I informed the development of investment strategies and candidate investments, including the appropriate pacing for the planning period. In particular:

- Customers favour replacing poor-condition assets to improve reliability or to reduce the risk of outages due to severe weather.
- Customers generally value, and are willing to pay for, improving or maintaining performance on reliability and resiliency.
- Customers support investments that enable economic growth and system visibility where the costs of these investments are within the directional bill impacts provided in the customer engagement exercise.

While customers generally supported investments that improve reliability and resiliency, the feedback also highlighted the importance of balancing system needs against affordability considerations. Hydro One considered this feedback together with asset condition, lifecycle requirements, operational needs, regulatory obligations and affordability in finalizing the investment plan. Phase II feedback was generally supportive, with approximately 75% or more customers indicating that an investment level at or above the draft plan represented a reasonable approach. However, in response to affordability concerns and broader customer feedback on the trade-offs between price and other outcomes, Hydro One subsequently reduced the final plan by approximately $1.5B, primarily through lower planned investment in certain reliability, severe weather response, IT and facilities programs.

Witness: Paul Ankrett; Peter Faltaous; Spencer Gill

As described in SPF Section 1.6, key customer feedback relevant to the distribution plan included the following:

- Across all customer types, a majority of customers support Hydro One spending at or above the level in the draft plan as it relates to distribution investments in overall system reliability, managing severe weather, and targeted reliability improvements.
- Customers support the investments included in the draft plan regarding the replacement of distribution assets in poor condition, such as overhead lines, transformer stations and underground cables to improve day-to-day reliability. A plurality of customers supports a level of spending more than the draft plan to further reduce the risk of outages.
- Regarding investments to manage the impacts of severe weather on the distribution system, customers support the level of investments in the draft plan with respect to relocating or reinforcing vulnerable power lines with more resilient equipment, clearing more overgrown trees and brush than historically, and more installation of automated “intelligent switches”. A plurality of customers would like to see an increased level of investment beyond the level in the draft plan.
- For investments to achieve targeted reliability, customers support the level of investment in the draft plan, including in respect of investing in community-scale and individual customer batteries to target reliability improvements for individual customers and communities that experience the poorest reliability.

3.1.5.4 THIRD PARTY STUDIES

The DSP is supported and informed by third party benchmarking and reports, listed in Table 12 below. The key findings from these studies are summarized in DSP Section 3.3.

Table 12 - List of All Third-Party Studies

Study/Report	Author	DSP References
Vegetation Management Program Study– Benchmarks vegetation management practices and programs	CN Utility Consulting Inc.	DSP Section 3.3 Attachment 1
Pole Replacement Program Study – Benchmarks pole replacement and maintenance practices	Guidehouse (formerly Navigant) and First Quartile	DSP Section 3.3 Attachment 2
Station Refurbishment Program Study – Benchmarks station replacement and maintenance practices	Guidehouse (formerly Navigant) and First Quartile	DSP Section 3.3 Attachment 2
AMI 2.0 Project Execution Process Review Study – Evaluates project execution processes	E-Source	DSP Section 3.3 Attachment 3
Distribution System Electricity Losses Study – Comprehensive analysis of distribution loss reduction practices employed by North American utilities.	Electricity Power Research Institute (EPRI)	DSP Section 3.3 Attachment 4
VASH – Provides a toolkit for assessing resiliency and reliability enhancements that is aligned with OEB requirement and principles of benefit-cost analysis.	Guidehouse	DSP Section 3.3 Attachment 5
Electrification Scenarios Study – Provides a scenario-based outlook of future peak load growth under three core electrification scenarios.	ERM	DSP Section 3.3 Attachment 6

3.1.5.5 ALIGNMENT WITH RRF OUTCOMES

In alignment with OEB requirements, individual programs are presented within the applicable OEB investment categories as defined by the primary trigger for the investment and include explicit consideration of RRF outcomes. Through the DSP, Hydro One is committed to meeting the OEB's RRF outcomes as follows:

- In respect of Customer Focus, the plan maintains and improves customer reliability in response to identified customer preferences.
- In respect of Operational Effectiveness, the plan achieves top-tier safety performance and eliminating serious injuries, improves long-term reliability through grid modernization and risk mitigation related to asset deterioration, and while prudently managing long-term system maintenance costs.
- In respect of Public Policy Responsiveness, the plan ensures compliance with mandated statutory and regulatory requirements.
- In respect of Financial Performance, the plan achieves manageable and stable rate impacts over the planning period through efficient operations and responsible investment to ensure the safety and reliability of the grid.

3.1.5.6 WORK EXECUTION CAPABILITY

The work execution strategy detailed in DSP Section 3.10 demonstrates that Hydro One has the capability, processes, and governance to deliver the proposed 2028–2032 investment plan.

The execution of the capital work program is influenced by a range of site conditions, including seasonality, terrain, and geographic location across the province. These factors are assessed and incorporated throughout all stages of project delivery, from scope of work development through execution, to support effective scheduling and resource planning. Planning activities also account for variables such as urban versus rural settings, site accessibility (on-road and off-road), and the potential need for specialized equipment and fleet. By proactively aligning project execution with these conditions, the organization can maintain capital delivery efficiency and effective execution of the proposed level of capital investment.

Hydro One's capital delivery encompasses both demand work and planned work. Planned program work involves a defined scope with the number of units to be replaced, the allocated budget, and annualized timelines for execution, with flexibility to accommodate seasonality requirements. The unpredictable nature of demand work in terms of volume, scope, and timing requires Hydro One Distribution to continuously assess and mitigate the potential impact that the execution of demand requests has on its ability to execute planned work.

3.1.5.7 PERFORMANCE MEASUREMENT

Consistent with the outcomes of the RRF, Hydro One utilizes two primary scorecards – the OEB-mandated Electricity Distributor Scorecard and its own supplementary Distribution OEB Scorecard – to comprehensively monitor results and set plan targets. The Distribution OEB Scorecard was developed by Hydro One to track additional performance outcomes that customers value and to measure areas where the Company has targeted sustained or improved performance. In setting targets for the 2028–2032 rate period, Hydro One has consistently adopted targets that exceed OEB industry standards, reflecting the Company's drive toward continuous improvement.

Hydro One is committed to these performance measures as it evaluates progress in executing its investment plan, balancing customer needs and preferences, compliance obligations, asset condition requirements, and rate impacts. Underpinning this framework are initiatives aimed at controlling costs, increasing productivity, and maintaining reliability across rural and urban areas – outcomes central to Hydro One's business objectives and the OEB's RRF.

A copy of the 2028-2032 Distribution scorecard is provided in Figure 15 below and DSP Section 3.5 provides detailed discussion of each measure, along with historical performance achievement and challenges in the current rate period.

RRFE Outcomes		Measure	2021	2022	2023	2024	2025	Trend	Hydro One Targets 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction	89%	87%	87%	88%	88%	▼	87%	87%	87%	87%	87%	82%	82%	82%	82%	82%
		Handling of Unplanned Outages Satisfaction[11]	78%	78%	78%	79%	80%	▲	80%	81%	82%	82%	83%	83%	83%	83%	83%	83%
		Call Centre Customer Satisfaction %	86%	86%	84%	86%	84%	▼	86%	86%	86%	86%	86%	80%	80%	80%	80%	80%
		myAccount Customer Satisfaction %[12]	60%	67%	68%	72%	66%	▲	66%	67%	68%	69%	70%	70%	70%	71%	71%	72%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit $	$11,158	$13,133	$15,216	$19,477	$18,191	▲	$10,608	$10,818	$11,032	$11,250	$11,473	$16,218	$16,837	$17,494	$18,181	$18,893
		Vegetation Management - Gross Defect Correction (OCP/OCP Flex) Cost per km $[13]	$4,019	$5,070	$ 6,996	$8,026	$8,580	▲	$3,824	$3,901	$3,980	$4,060	$4,140	$7,484	$7,633	$7,786	$7,914	$8,053
		Station Renewal - Gross Cost per MVA in $	$356,899	$655,244	No project in-serviced	$818,524	$917,979	▲	$425,000	$423,000	$421,000	$419,000	$417,000	$654,773	$667,869	$681,226	$694,850	$708,747
		OM&A dollars per customer	$409	$461	$459	$474	$419	▲	$416	$418	$469	$453	$462	$626	-	-	-	-
		OM&A dollars per km of line	$4,779	$5,441	$5,469	$5,709	$5,058	▲	$4,798	$4,838	$5,393	$5,506	$5,631	$7,650	-	-	-	-
		KM of Forestry Managed	New Metric											15,833	15,833	15,833	15,833	15,833
		DCAI	New Metric											100%	100%	100%	100%	100%
	System Reliability	SAIDI for Equipment Caused Interruptions	2.1	2.6	2.0	1.7	1.9	▼	1.7	1.6	1.5	1.9	1.9	1.9	1.8	1.8	1.8	1.8
		SAIDI for Vegetation Caused Interruptions	2.7	2.5	1.7	2.0	2.1	▼	1.9	1.7	1.7	2.0	2.0	2.0	1.9	1.9	1.8	1.8
		SAIDI - Rural - duration in hours	7.5	8.0	8.8	9.2	10.0	▲	5.2	4.8	4.7	9.6	9.5	9.4	9.3	9.1	9.0	8.9
		SAIFI - Rural - frequency of outages	2.6	2.8	3.2	3.1	3.3	▲	2.3	2.1	2.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1
		SAIDI - Urban - duration in hours	2.8	2.8	3.5	3.1	2.9	▲	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	1.4	1.3	1.6	1.5	1.6	▲	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
		Interruptions per LDA	1.3	1.5	1.7	1.3	1.2	▼	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
		Flexibility & Local Energy Efficiency Programs	New Metric											56,600	65,200	71,900	77,100	81,300
		Enabling Remote Operable Capabilities	New Metric											90% of M-class feeders by the end of 2032				
		Load Capacity Constrained Distribution Stations	New Metric											0-4% by the end of 2032				

Figure 15: Hydro One Distribution OEB Scorecard

[11] As described in the sections that follow, the methodology for this measure was changed in 2020.
[12] Ibid.
[13] This measure is being renamed from Gross Cyclical Cost per km $ to better reflect tracking of the OCP/OCP Flex program costs. There are no changes to the calculation methodology.

SECTION 3.2 – DSP – ASSET INFORMATION AND LIFECYCLE 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. This information supports the identification and prioritization of distribution asset maintenance and renewal requirements described elsewhere in the Distribution System Plan (DSP). Unless otherwise noted, the information presented is current as of December 31, 2025.

Hydro One operates a large and geographically dispersed distribution system serving more than 1.5 million customers across the Hydro One, Orillia (ORZ) and Peterborough (PRZ) Rate Zones. The distribution system includes distributing and regulating stations (station assets are discussed in Section 3.2.2), overhead and underground distribution lines and supporting rights-of-way ("ROWs") (distribution line assets are discussed in Section 3.2.3), and wholesale and retail revenue metering assets (Section 3.2.4).

Table 1 below summarizes the principal distribution asset classes addressed in this section and provides an indication of the scale of Hydro One's distribution asset base. Hydro One currently does not have any transmission or high voltage assets (>50kV) deemed previously by the OEB as distribution assets.

Table 1 - Distribution Assets

Asset Group	Asset Component	Population / Extent
Distribution Stations	Distributing and regulating stations	1,009 stations
	Station transformers and regulators	1,228 transformers
	Station reclosers	2,299 three-phase equivalent reclosers
	Station breakers	261 breakers
	Station switches	2,653 three-phase switches
	Station fuses	1,852 three-phase fuses
	Mobile Unit Substations ("MUSs")	33 units
	Other Station Assets	Station structures, buildings, MUS connection structures, fences, grounding systems, station service transformers, bus systems, spill containment systems, protection relays, Intelligent Electronic Devices ("IEDs")
Distribution Lines	Poles	1.6 million poles
	Cross arms	Approximately 500,000
	Primary conductor	114,000 km of overhead conductor, 7,400 km of underground cable 4,100 km of submarine cable
	Line transformers	Approximately 550,000 line transformers
Rights-of-Way	Distribution ROWs	Approximately 104,000 km
Revenue Metering	Retail revenue meters	Approximately 1.5 million meters
	Wholesale revenue meters	860 meters 1,725 instrument transformers

Hydro One does not apply a uniform replacement approach to all distribution assets. Lifecycle strategies reflect the physical characteristics of each asset class, the availability and reliability of condition information, the consequences and cost of failure, opportunities to repair or refurbish the existing asset, and the cost-effectiveness of available lifecycle interventions. The sections below summarize the principal condition, demographic, performance and lifecycle considerations across the distribution asset portfolio. The asset-specific sections that follow provide further supporting information.

3.2.1.1 ASSET CONDITION

For asset classes where physical or functional condition can be reliably and economically assessed, asset condition is a primary input to Hydro One's maintenance and renewal

decisions. 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. As assets deteriorate, their probability of failure and their associated reliability, safety, environmental and operational risks can increase. Planned lifecycle interventions allow Hydro One to address deterioration before these risks materialize and to preserve the safe and reliable operation of the distribution system.

Hydro One assesses asset condition using methods appropriate to each asset class. These include visual inspections, thermographic inspections, diagnostic testing, oil analysis, functional testing, equipment operating history, quantitative structural measurements and maintenance history. For example, station transformer assessments use oil sampling, visual and thermographic inspections and diagnostic testing, while wood pole assessments use visual inspections and quantitative testing of remaining structural strength.

Where Hydro One maintains a condition profile, assets are generally categorized as Good, Fair or Poor. These categories provide a common means of summarizing asset condition. However, the assessment criteria and information used to determine the condition rating are asset-specific. Table 2 below provides the general interpretation of these condition categories and the corresponding lifecycle response.

Table 2 - Asset Condition Categories

Condition	General Interpretation	Typical Lifecycle Response
Good	The asset does not exhibit material deterioration or deficiencies that require condition-driven intervention.	Continue normal inspection and preventive maintenance.
Fair	The asset exhibits deterioration or deficiencies that warrant additional monitoring and/or corrective maintenance but can generally remain in service.	Monitor condition and undertake corrective maintenance where appropriate. Replacement is generally not required solely because the asset is rated Fair.
Poor	The asset exhibits significant deterioration or deficiencies associated with a higher probability of failure or an inability to continue performing its intended function over the longer term without intervention.	Assess for corrective repair, refurbishment or planned replacement based on the nature of the deficiency, consequence of failure, cost-effectiveness of available interventions.

For asset classes with established condition profiles, asset condition is a principal driver of planned maintenance, refurbishment and renewal. Planned intervention on poor condition assets is necessary to manage deterioration in a prudent and cost-effective manner, mitigate longer-term reliability, safety, environmental and operational risks, and preserve safe and reliable service for customers.

A Poor condition rating does not automatically result in immediate replacement. Hydro One considers whether the identified deficiency can be economically corrected or whether refurbishment can extend the remaining service life of the asset. The consequence of failure and relative risk are also considered in determining the timing of intervention. This approach allows Hydro One to continue operating serviceable assets while directing maintenance and capital investment toward assets presenting greater risk.

Where physical condition cannot reasonably or economically be assessed or is not feasible given the nature of a particular asset (e.g. electronic components of meters), Hydro One uses other relevant information to inform lifecycle decisions, including age, asset performance, failure history, technology obsolescence, availability of vendor support and replacement parts, and applicable compliance requirements. Table 3 summarizes the availability of condition information across the principal distribution asset classes.

Table 3 - Availability of Asset Condition Information

Asset Class / Component	Condition Assessment	Principal Approach
Station transformers	Yes	Inspection, oil sampling and diagnostic testing
Station reclosers	Yes	Counter operations, identified defects from inspection or failure
Station breakers	Partial	Diagnostic testing
Station switches, fuses, other station assets	Partial	Condition profiles are maintained for selected components. Some assets are managed based on identified defects or failure.
MUSs	Yes	Condition of transformer, electrical components and trailer
Poles and cross arms	Yes	Visual inspection and, for wood poles, quantitative structural testing
Overhead conductor	No comprehensive condition profile	Identified defects from visual inspection
Submarine cable	Yes	Visual inspection and diagnostic testing where appropriate
Underground cable	No comprehensive condition profile	Defects, age and performance information. Diagnostic testing is planned beginning in 2028
Line transformers	No comprehensive condition profile	Performance, age and observed deficiencies are used as applicable
Revenue meters	No comprehensive condition profile	Age, failures, technology obsolescence, regulatory requirements and performance
Distribution ROWs	Not applicable	Vegetation condition is assessed using defect density, vegetation characteristics and time since last clearance

Table 4 below summarizes key condition information for major distribution asset classes.

Table 4 - Summary of Distribution Asset Condition

Asset	Population in Poor Condition	Number of asset units in Poor Condition
Station transformers	19% (0% – ORZ 36% – PRZ) [1]	231 (0 – ORZ 11 – PRZ)
Mobile Unit Substations	24%	8
Poles	6%	99,000
Submarine cable	10%	1,350

Overall, Hydro One has substantial populations of distribution assets in poor condition that require lifecycle intervention. These condition-driven needs have been compounded by the reprioritization of planned renewal work in certain asset classes during the 2023–2027 period and are expected to increase as additional assets deteriorate with age. Increased planned renewal during the 2028–2032 period is therefore necessary to address the accumulating condition-driven requirements in a prudent and cost-effective manner, mitigate longer-term reliability, safety, environmental and operational risks, and preserve safe and reliable service for customers.

3.2.1.2 ASSET DEMOGRAPHICS

Asset demographics provide a population-level view of the maturity of Hydro One's distribution assets and the rate at which lifecycle requirements may emerge.

Expected Service Life (ESL) represents the average period 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.

An asset reaching its ESL does not mean that it must be replaced. Assets that remain in acceptable condition may continue to operate beyond ESL. Similarly, an asset may require intervention before reaching ESL where condition, performance, obsolescence or another

[1] ORZ – Orillia Rate Zone, PRZ – Peterborough Rate Zone

system requirement warrants earlier action. Age becomes a more significant lifecycle indicator where physical condition cannot be directly or economically assessed.

Table 5 below summarizes the available age and ESL information for key asset populations. Where available, the table compares the proportion of the population at or beyond ESL in 2025 with the proportion that would be at or beyond ESL by 2032 in the absence of asset replacement.

Table 5 - Summary of Distribution Key Asset Demographics

Asset Component	Average Age	ESL	Population Beyond ESL, 2020	Population Beyond ESL, 2025	Population Beyond ESL by 2032, Absent Replacement
Station transformers	43 years (32 - ORZ, 58 - PRZ)	50 years	33%	45% (36% - ORZ, 87% - PRZ)	55% (45% - ORZ, 94% - PRZ)
MUS transformers	35 years	40 years	46%	48%	61%
Poles	43.7 years	60 years	23%	28%	35%
Underground cable	22 years	30 years	Unavailable	30%	43%
Retail Revenue Meters	11.3	15 years	0%	50%	68%

The demographic profile indicates increasing renewal pressure across several major distribution asset populations. This trend is already evident in the recent historical demographics: between 2020 and 2025, the proportion of Hydro One Rate Zone station transformers beyond their ESL increased from approximately 33% to 45%, while the proportion of poles 60 years of age or older increased from approximately 23% to 28%. Significant portions of the station transformer, MUS, pole, underground cable and legacy metering populations are therefore already at or beyond their expected service lives, and the proportion of assets reaching advanced age will continue to increase through the 2028–2032 period. For example, absent replacement, the proportion of Hydro One Rate Zone station transformers at or beyond ESL would increase from 45% in 2025 to 55% by 2032, while the proportion of poles 60 years of age or older would increase from 28% to

35%. As these populations continue to age, a greater number of assets will enter age ranges associated with increased deterioration, obsolescence and failure risk, resulting in increasing condition-driven renewal requirements. This aging profile is therefore an important driver of Hydro One's increased system renewal investment during the 2028–2032 period.

3.2.1.3 ASSET PERFORMANCE

Hydro One monitors asset performance to identify emerging issues, assess whether existing lifecycle strategies remain appropriate and support maintenance and capital prioritization. The appropriate performance measure depends on the function and characteristics of the asset class.

For station equipment, performance is commonly assessed through equipment failures or failures to operate as required. For line assets, performance is generally reflected through asset-caused customer interruptions and associated reliability impacts. ROW performance is assessed through vegetation-related outages and vegetation-management indicators. Metering performance is assessed based on meter and communication performance, billing accuracy, and the operational impacts associated with meter failures.

Hydro One's distribution system is predominantly radial, reflecting the most cost-effective approach to delivering electricity to end-use customers. In many locations there is no immediately available alternate supply path following an equipment failure, such that equipment failures will generally result in customer outages until the issue is rectified or a temporary mitigation measure is implemented (e.g., installation of a MUS to restore service following a station transformer failure). The customer impact of an asset failure therefore depends not only on the probability of failure, but also on the number of customers supplied by the affected equipment, system configuration, accessibility and the time required to repair, replace or bypass the failed asset.

Hydro One monitors asset performance to identify emerging issues, assess whether existing lifecycle strategies remain appropriate and support maintenance and capital

prioritization. Asset performance is also a material contributor to overall distribution system reliability.

Distribution system reliability performance has deteriorated in recent years. Between 2021 and 2025, Distribution SAIDI increased from approximately 6.5 hours to 8.2 hours, while Distribution SAIFI increased from approximately 2.4 to 2.9 interruptions. Equipment failure remains one of the principal contributors to these reliability outcomes. Excluding Force Majeure and Loss of Supply events, equipment failures accounted for approximately one-third of annual Distribution SAIDI over this period, as shown in Figure 1.

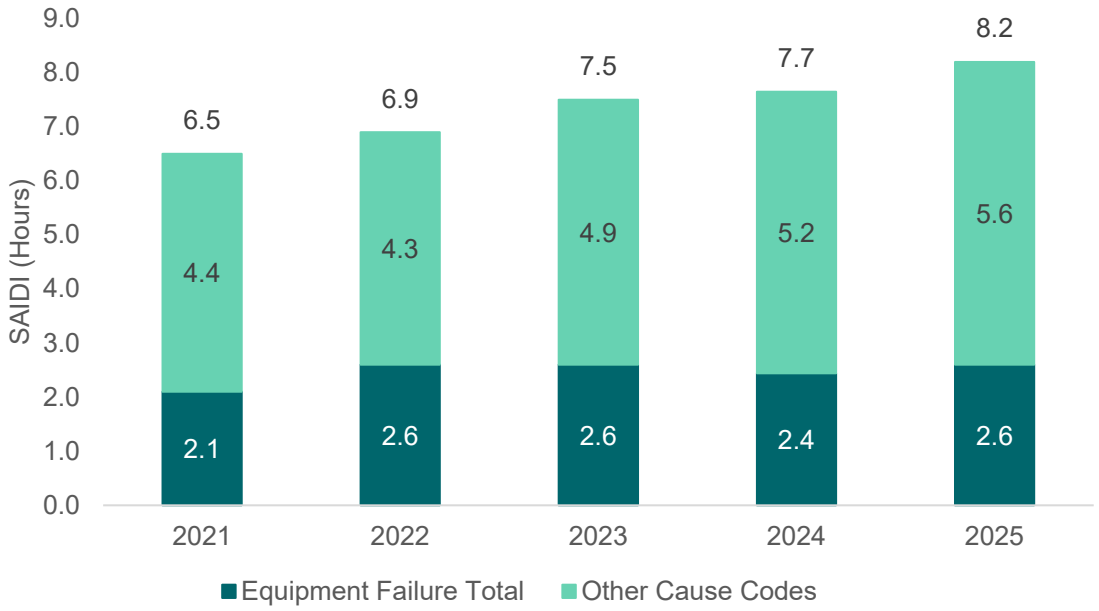


Figure 1: Portion of Annual SAIDI (Excluding Force Majeure and Loss of Supply Events) Caused by Equipment Failure

Table 6 below summarizes key performance information for major distribution asset classes.

Table 6 - Summary of Key Distribution Asset Performance (2016 – 2025)

Asset Component	Current / Historical Performance
Station transformers	Combined Class 1 and Class 2 failures ranged from 7 to 19 annually between 2016 and 2025, with 19 in 2025. (ORZ – no failures since 2021 PRZ – one Class 1 failure in 2023, one Class 2 failure in 2022)
MUSs	Five MUSs were retired between 2016 and 2025, associated principally with transformer failure or deterioration. Three MUSs had been replaced by year-end 2025.
Poles	Pole-related interruptions, excluding Force Majeure events, increased from 234 in 2016 to 570 in 2025.
Underground cable	Number of interruptions has increased by 60% since 2016, principally associated with aging direct-buried cable.
Submarine cable	Average of approximately 87 interruptions per year in 2016 -2025
Retail revenue meters	181,000 meter failures since 2022 (~12% of the meter population).

Asset performance is interpreted together with condition and demographics rather than used as a common replacement threshold. For example, station transformer diagnostic testing can identify deterioration before a customer interruption occurs. As a result, a condition-driven intervention may prevent a failure that would otherwise appear in historical reliability data. Conversely, an outage associated with a pole, conductor or other line component may result from external causes rather than underlying asset deterioration.

Performance information has greater weight where physical condition cannot be directly or economically assessed. The approximately 75% increase in underground cable interruptions, together with the mature cable population, supports a transition toward diagnostic testing and targeted planned intervention. Similarly, increasing meter failures and field activity provide an important indicator of the end-of-life characteristics of the AMI 1.0 system.

Overall, the system-level and asset-specific performance trends indicate increasing asset-related reliability pressure across portions of Hydro One's distribution system. Equipment failure remains a material contributor to customer interruptions, while the performance trends summarized above indicate that deterioration in several major asset populations is increasingly translating into unplanned failures and customer impacts. Together with the

condition and demographic trends described above, this performance information supports increased planned renewal during the 2028–2032 period to address growing asset-related risks and reduce reliance on reactive replacement.

3.2.1.4 ASSET LIFECYCLE MANAGEMENT

Hydro One manages its distribution assets using lifecycle strategies appropriate to the characteristics of each asset class. These strategies balance asset condition, demographics, performance, probability and consequence of failure, maintenance requirements, refurbishment opportunities, obsolescence and lifecycle cost.

Distribution assets are managed through a combination of preventive maintenance, corrective maintenance, refurbishment, planned capital replacement and demand work. Hydro One's inspection practices and frequencies are established having regard to the characteristics of the asset and applicable requirements, including the Minimum Inspection Requirements under the OEB's Distribution System Code.

Where maintenance or refurbishment can economically address an identified deficiency and extend asset service life, Hydro One generally continues to use the existing asset. Planned replacement is used where condition, performance, failure consequence, obsolescence or lifecycle economics support replacement rather than further repair. Run-to-failure is used for selected asset classes where proactive assessment or replacement would not be cost-effective relative to the consequence and cost of individual failure.

Where an identified renewal need occurs within a legacy or otherwise constrained part of the distribution system, Hydro One also considers whether the asset should be renewed on a like-for-like basis or whether a broader solution, such as station reconfiguration, voltage conversion, feeder rebuild or relocation, or other system modification provides a better lifecycle outcome. These alternatives can address the underlying asset need while also improving system standardization, accessibility, transfer capability, reliability or resiliency where those additional benefits justify the incremental scope.

Capital replacement candidates are prioritized based on risk. For assets subject to Hydro One's Risk Spend Efficiency (RSE) methodology, the relative probability and consequence of failure and the risk reduction achieved through the proposed investment inform the order in which identified needs are addressed. Please refer to DSP Section 3.7 for further information on Hydro One's investment planning and prioritization process.

Table 7 below summarizes the principal lifecycle strategies applied to the major distribution asset classes.

Table 7 - Summary of Key Distribution Asset Lifecycle Strategies

Asset Component	Primary Lifecycle Strategy
Station transformers	Predictive testing, and condition-based maintenance, repair and planned replacement
MUSs	Periodic inspection and maintenance, condition-based repair and replacement, and management of overall fleet availability
Poles	Inspection, test-and-treat, chemical and mechanical refurbishment, and condition-based replacement
Underground cable	Transition from predominantly reactive repair toward diagnostic testing, rejuvenation and targeted planned replacement
Submarine cable	Inspection, repair or refurbishment and condition- or safety-driven replacement
Retail revenue meters	Individual run-to-failure during normal service life and system-wide replacement when the metering system reaches the end-of-service-life stage

Hydro One applies different lifecycle strategies to reflect differences in asset characteristics, available condition information and the consequences and cost of failure. A condition-driven planned replacement strategy is appropriate for a high-consequence asset such as a station transformer, where diagnostic information can identify deterioration and failure can result in lengthy customer interruptions.

Hydro One also adjusts lifecycle strategies as asset populations and risks change. Underground cables have historically been managed predominantly through reactive repair because cable failures were relatively infrequent. The aging direct-buried cable population and approximately 75% increase in cable interruptions since 2016 support greater use of diagnostics, rejuvenation and targeted planned replacement. Similarly, AMI

1.0 has transitioned from individual failure replacement during its normal service-life stage to system-wide replacement as the technology has reached end of life.

For long-lived assets such as station transformers and poles, Hydro One combines planned replacement with maintenance and refurbishment to retain serviceable assets where economical. This avoids replacing assets solely because they have reached a specified age while progressively addressing assets whose condition and risk require intervention.

Together, these lifecycle strategies align maintenance, refurbishment and capital renewal decisions with asset condition, demographics, performance and risk. The asset-specific sections that follow provide further information on the applicable inspection, maintenance, refurbishment and replacement practices for each major asset class.

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

3.2.2.1.1 ASSET DESCRIPTION / PURPOSE

As the costliest component of Hydro One's distribution station asset base, station transformers (see example shown in Figure 2 below) convert a high voltage (typically 115, 44 or 27.6kV) to a lower distribution voltage (typically 27.6, 25, 13.8, 12.47, 8.32 or 4.16kV). This asset class also includes regulating transformers, which provide voltage control on the distribution system.



Figure 2: Station Transformer

3.2.2.1.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.2.1.2.1 ASSET DEMOGRAPHICS

Hydro One owns and operates 1,228 distribution station transformers, as categorized in Table 8 below by primary voltage level.

Table 8 - Transformer Count by Voltage Level

Primary Voltage Level	Hydro One Rate Zone	Orillia Rate Zone	Peterborough Rate Zone
230kV	1		
115kV	140		
44kV	776	11	31
27.6kV	224		
< 27.6kV	45		

Figure 3 below shows the demographics of station transformers in the Hydro One Rate Zone, which have an ESL of 50 years. The current average age of station transformers in the Hydro One Rate Zone is 43 years, and 45% (529 transformers) of the fleet are beyond their ESL. If no capital replacements are undertaken, an additional 10% (122 transformers)

will reach or exceed 50 years by 2032, which would bring the total to 55% (651 transformers).

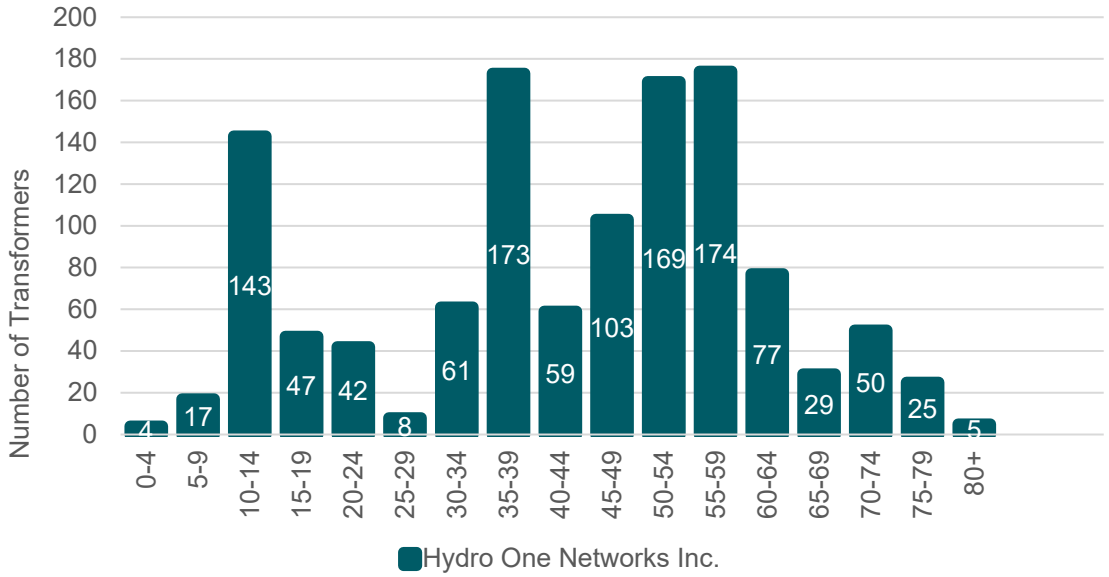


Figure 3: Demographics of the Distribution Station Transformers in Hydro One Rate Zone

Figure 4 below shows the demographics of station transformers in the Orillia Rate Zone. The current average age of station transformers in the Orillia Rate Zone is 32 years, and 36% (4 transformers) of the fleet are beyond their ESL. If no capital replacements are undertaken, an additional transformer will reach or exceed 50 years by 2032, which would bring the total to 45% (5 transformers).

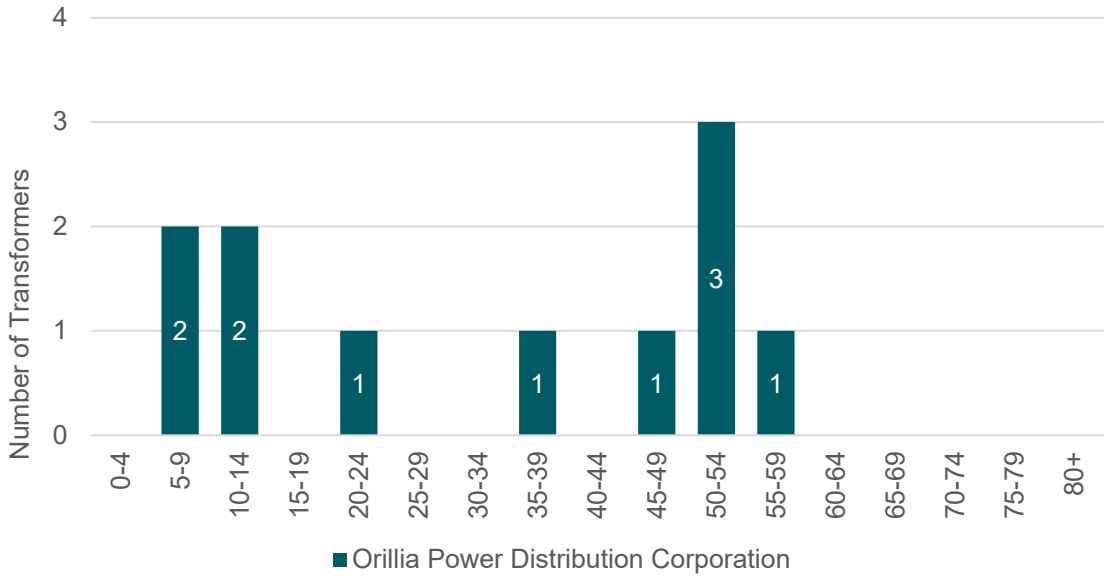


Figure 4: Demographics of the Distribution Station Transformers in Orillia Rate Zone

Figure 5 below shows the demographics of station transformers in the Peterborough Rate Zone. The current average age of station transformers in the Peterborough Rate Zone is 58 years and 87% (27 transformers) of the fleet are beyond their ESL. If no capital replacements are undertaken, an additional 7% (2 transformers) will reach or exceed 50 years by 2032, which would bring the total to 94% (29 transformers).

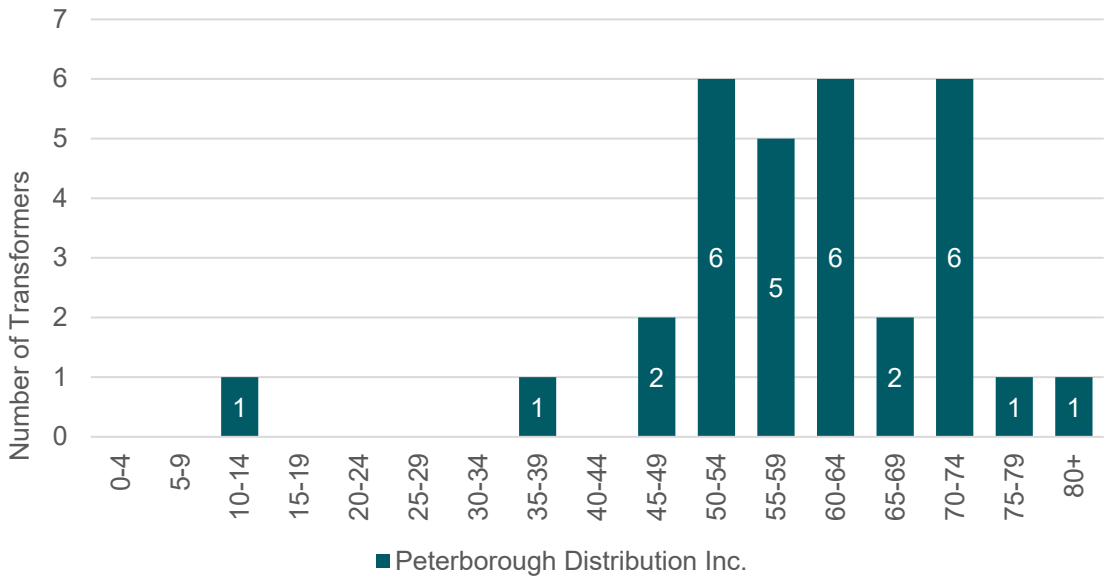


Figure 5: Demographics of the Distribution Station Transformers in Peterborough Rate Zone

3.2.2.1.2.2 ASSET CONDITION

Approximately 19% (231) of Hydro One Rate Zone station transformers fall into the poor condition category, with 21% (244) in fair condition and 60% (711) in good condition (Figure 6).

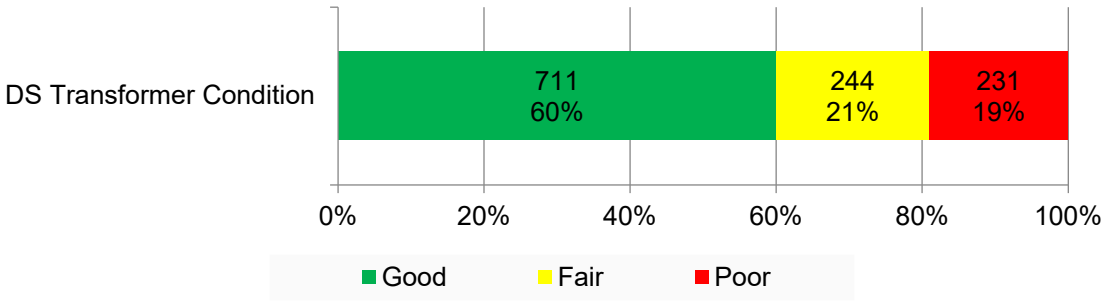


Figure 6: Condition of the Distribution Station Transformers in Hydro One Rate Zone

Approximately 18% (2) of Orillia Rate Zone station transformers fall into the fair condition category, with 82% (9) in good condition (Figure 7).

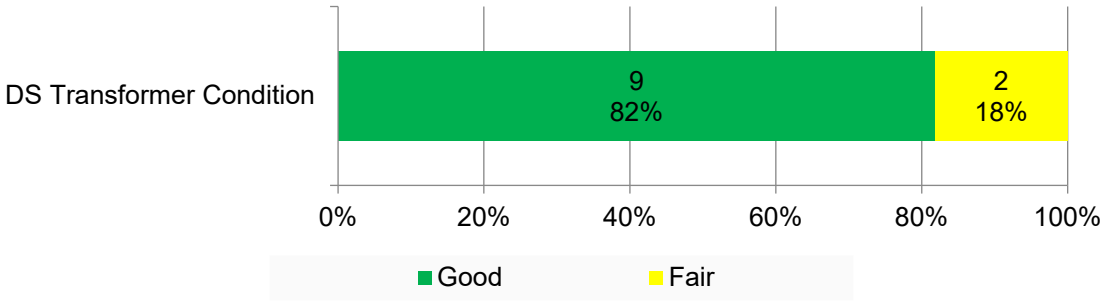


Figure 7: Condition of the Distribution Station Transformers in Orillia Rate Zone

Approximately 36% (11) of Peterborough Rate Zone station transformers fall into the poor condition category, with 3% (1) in fair condition and 61% (19) in good condition (Figure 8).

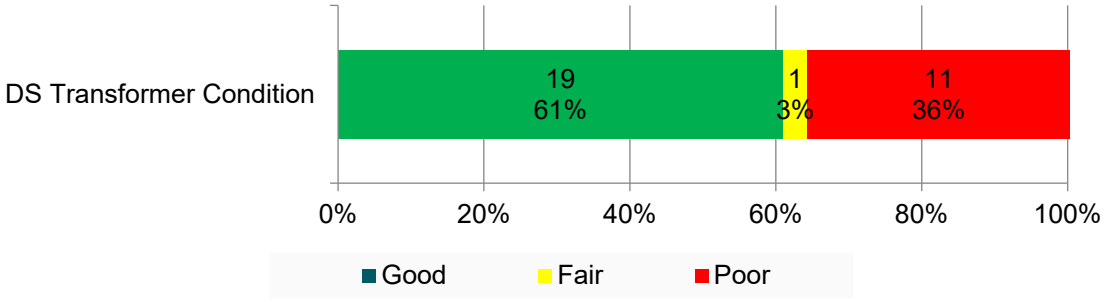


Figure 8: Condition of the Distribution Station Transformers in Peterborough Rate Zone

Transformers in poor condition have significant deterioration or deficiencies associated with elevated risk of failure and require lifecycle intervention. Depending on the nature of the deficiency, transformer age, repairability and consequence of failure, the appropriate intervention may include planned replacement or corrective repair.

Many factors lead to the degradation of a transformer's internal components over time, including transformer loading, which has increased to an average of 75% of nameplate

rating across Hydro One's distribution system, switching, lightning surges, moisture contamination, and degradation of paper insulation. The resulting deterioration in asset condition is the leading indicator of increased transformer failure risk.

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.

The condition profile of the transformer fleet has remained broadly stable since 2020, in part because Hydro One has continued to address repairable deficiencies through condition-based corrective repairs. Over the same period, however, the underlying transformer population has become materially older. As the fleet ages, the nature of the identified deterioration becomes increasingly important in determining the appropriate lifecycle intervention. Certain deficiencies can continue to be addressed economically through corrective repair, allowing otherwise serviceable transformers to remain in operation. Other forms of deterioration, including degradation of winding and paper insulation, are not amenable to component-level corrective repairs. The availability of replacement parts for legacy components, including older under-load tap-changers, can also constrain the ability to continue repairing certain transformers. These factors increase the need for planned replacement as the transformer population ages.

Testing, inspection and condition monitoring therefore allow Hydro One to identify deteriorating transformers and determine whether corrective repair or planned replacement is the appropriate intervention before an in-service failure occurs (see "Asset Lifecycle" section below regarding repair and replace decisions).

3.2.2.1.2.3 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 are available.

An MUS takes approximately 7 hours to travel to a station and be connected before power can be temporarily restored to customers. In severe cases, these outages can last up to 21 hours depending on the distance from the nearest available MUS to the station, and the availability and condition of the MUS structures 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. These interruptions last approximately 7 hours. Historically, approximately 61% of Class 1 distribution station transformer failures have required replacement, and 39% were repairable.
- *Class 2 Failures* – Station transformer failures avoided through timely corrective or capital intervention. Such intervention is triggered by oil sampling indicating that failure is imminent. 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 28% of Class 2 transformer failures have required replacement and 72% were repairable.

The historical replacement and repair ratios for Class 1 and Class 2 failures are used to inform the forecast of station transformer work volumes over the 2028–2032 period, including the estimated split between renewal activities and corrective work.

The number of transformer failures (Class 1) and number of imminent failures avoided by removal of transformers from service (Class 2) in the Hydro One Rate Zone are shown in Figure 9.

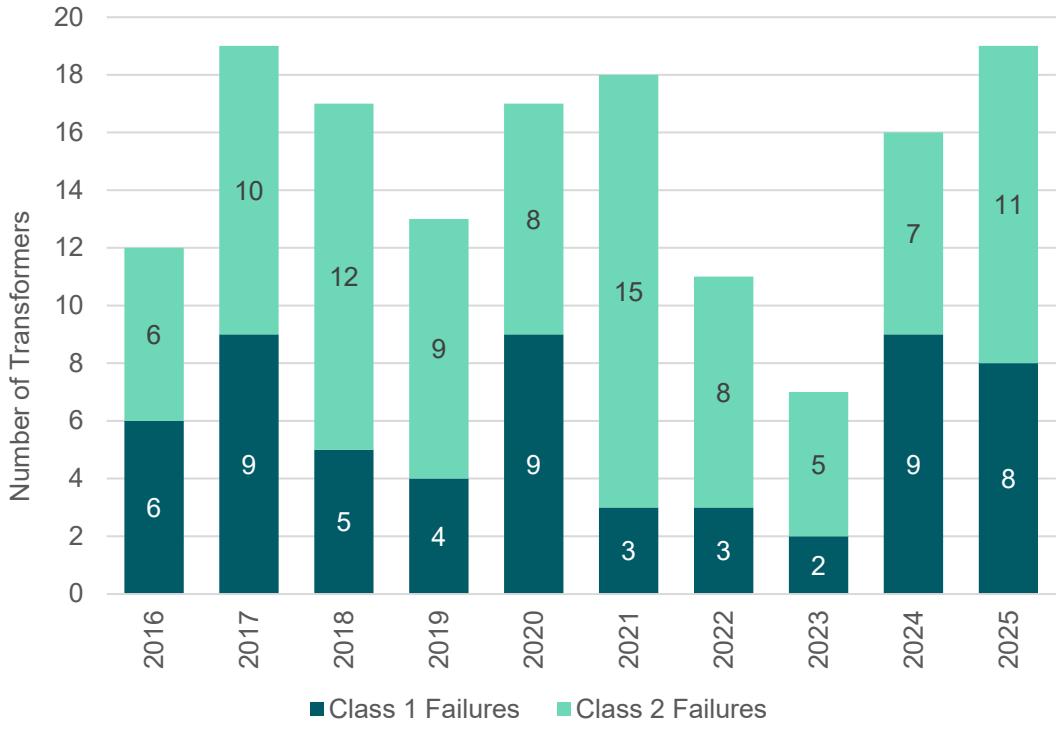


Figure 9: Failures of Station Transformers in Hydro One Rate Zone

In the Hydro One Rate Zone, from 2016 to 2025, the total Class 1 and Class 2 failures have ranged from 7 to 19 each year, with 2025 experiencing 19 failures. Annual oil sampling and close monitoring of transformers with poor condition have allowed Hydro One to identify several imminent failures and intervene before they result in lengthy customer interruptions.

Hydro One has historically managed transformer failure risk through a combination of condition monitoring, corrective repair and planned replacement. Corrective repair remains an appropriate lifecycle intervention where the identified deterioration can be economically addressed, and sufficient service life can be retained. However, as the transformer population ages, a greater proportion of deteriorated transformers are

expected to exhibit conditions for which continued corrective repair is no longer technically feasible or economic.

For the 2028-2032 period, Hydro One plans to address 86 station transformers through the Distribution Station Renewal Program (DSP Section 3.11, D-SR-04) and an additional 20 station transformers through System Upgrades Driven by Load Growth investments (DSP Section 3.11, D-SS-01). Needs are coordinated between D-SR-04 and D-SS-01 to identify opportunities where a single investment, driven by earlier needs, can address both asset condition and load growth needs. The Distribution Station Renewal Program will target transformers whose condition and risk warrant capital intervention and are intended to manage the increasing failure exposure associated with the aging transformer fleet. With the proposed replacements, Hydro One expects Class 1 and Class 2 transformer failures to remain generally within the range experienced in recent historical years. The reduced level of planned replacement during the 2023-2027 period has deferred a significant number of condition-driven renewal needs entering the next rate period, making a higher level of planned replacement necessary to manage this risk.

Planned replacement also reduces the operational consequences associated with lengthy MUS deployments. For a planned transformer replacement, engineering, site preparation, material procurement and other preparatory activities can generally be completed before the existing transformer is removed from service. By contrast, following an unplanned failure requiring replacement, scope development, engineering, procurement and construction activities begin after the failure occurs. In these circumstances, an MUS can remain committed to a station for more than 12 months, compared to approximately five months for a planned replacement. Longer MUS deployments reduce fleet availability for other transformer failures, planned corrective maintenance and capital work. In such a scenario, 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 extended customer interruptions which could last days.

In the Orillia Rate Zone, no transformer failures have occurred since the acquisition in 2021. Given that 82% of the transformers are in good condition, and the remaining 18%

in fair condition, it is not expected that a significant number of failures would occur during the 2028-2032 rate period in the absence of planned replacements. However, Hydro One Distribution will continue to monitor the condition of the Orillia Rate Zone transformer fleet year-over-year.

In the Peterborough Rate Zone, one class 2 transformer failure occurred in 2022, and one class 1 transformer failure occurred in 2023. Currently, 87% of the fleet are at or beyond their 50-year ESL. From 2028-2032 an additional 7% will reach their ESL if no planned replacements are undertaken. As 36% of the transformers are in poor condition, there is high likelihood that additional transformer failures will occur during the 2028-2032 period. Planned transformer replacements will be required to limit the number of failures.

Figure 10 below represents the yearly contribution of station transformer Class 1 failures to System Average Interruption Duration Index (SAIDI) in the Hydro One Rate Zone. The annual average transformer SAIDI contribution resulting from Class 1 failures has been 0.019 hours.

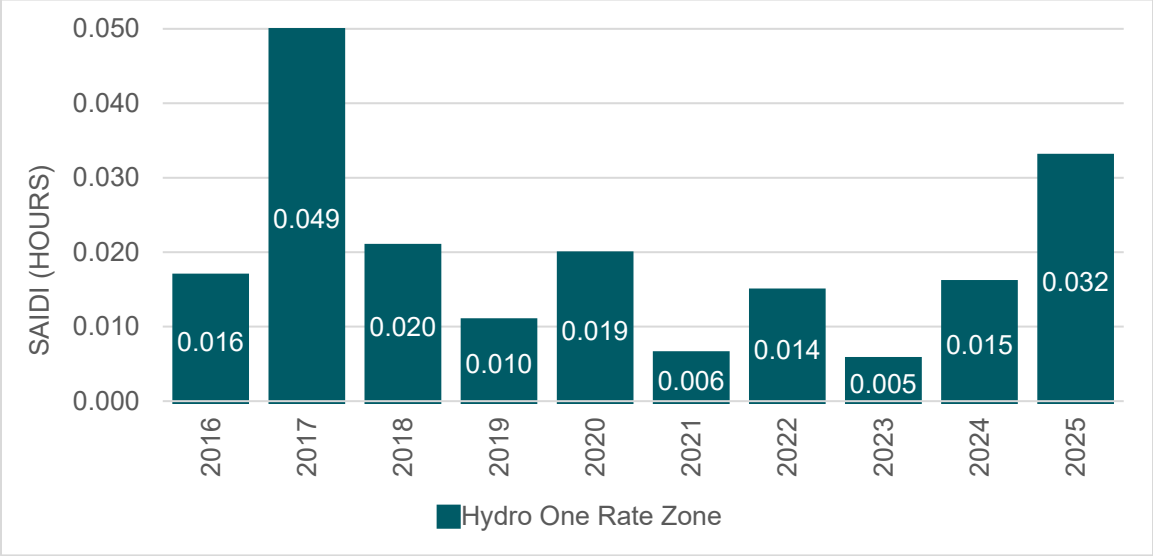


Figure 10: DS Transformer SAIDI in Hydro One Rate Zone

3.2.2.1.3 LIFECYCLE STRATEGY

Hydro One mitigates the risk of distribution station transformer failures through a lifecycle strategy that prioritizes predictive testing, condition-based corrective maintenance, and the planned replacement of assets. This approach is designed to proactively manage asset deterioration, reduce the likelihood of in-service failures, and minimize interruption impact on downstream customers.

Transformers assessed to be in fair condition are generally managed through targeted corrective maintenance activities combined with ongoing condition monitoring. This approach is intended to address identified issues, manage asset health, and prevent further degradation while maintaining acceptable performance.

Transformers assessed to be in poor condition are evaluated for either replacement or further corrective maintenance. The determination of the appropriate intervention is informed by a range of factors, including the age of the unit, the scope and cost-effectiveness of the required corrective work, and the consequences of failure, including the impact to downstream customers.

As transformers age, the ability to continue relying on corrective repair generally decreases. Deficiencies associated with components such as tap-changers, oil leaks or other repairable equipment may be corrected where technically and economically practical. In contrast, deterioration of winding and paper insulation is not amenable to component-level repair, and replacement-part availability for certain legacy equipment can further constrain corrective options. As a result, planned replacement assumes a greater role in managing the condition and risk of the aging transformer population.

This risk-informed, condition-driven approach ensures that interventions are proportionate to asset health and system impact, while supporting the safe, reliable, and cost-effective operation of the distribution network.

3.2.2.1.3.1 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* – 115kV and 230kV 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 two 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.

3.2.2.1.3.2 REPLACEMENT & MAINTENANCE

Fair condition transformers are generally candidates for corrective repair or monitoring. These 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 on a case-by-case basis. The repair versus replacement decision is driven by factors such as condition, age, and magnitude of corrective work. Certain deficiencies can be addressed through component repair. Other deterioration, including winding and paper-insulation degradation, cannot generally be corrected through component-level repair. Obsolescence and the availability of parts for legacy equipment, including older under-load tap-changers can also make continued repair impractical or uneconomical.

Younger transformers in poor condition are typically candidates for corrective repair. Performing corrective repairs on younger transformers normally allows them to reach or exceed their 50-year ESL. Hydro One continues to monitor the condition of transformers

through oil sampling as they exceed their ESL, considering candidates for replacement as appropriate. Most transformers in poor condition beyond their ESL are candidates for replacement as opposed to corrective repair. This is because correctively repairing transformers beyond this age may only slightly extend their service lives, which would not be economical as more components are expected to fail and need to be further addressed.

For identified transformer replacement candidates, transformers identified with the highest risk of failure and largest customer impact are prioritized to be addressed first. Factors that feed into the risk assessment include transformer condition, downstream customer counts, and estimated outage duration if the transformer fails.

Poor condition transformers that have been prioritized for capital intervention based on risk assessment are addressed through the following alternatives through DSP Section 3.11, D-SR-04:

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

The effective long-term management of the station transformer fleet therefore requires a combination of continued condition monitoring and corrective maintenance for repairable deterioration, together with planned capital replacement of higher-risk transformers for which further repair is no longer the appropriate lifecycle response. As the transformer population continues to age, planned renewal is increasingly important to manage failure risk, reduce reliance on unplanned replacement and preserve safe and reliable service to customers.

3.2.2.2 STATION RECLOSERS AND BREAKERS

3.2.2.2.1 ASSET DESCRIPTION / PURPOSE

3.2.2.2.1.1 RECLOSERS

Hydro One currently manages 2,299 three-phase equivalent distribution station reclosers across the Hydro One, Orillia and Peterborough Rate Zones (see example shown in Figure 11 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.

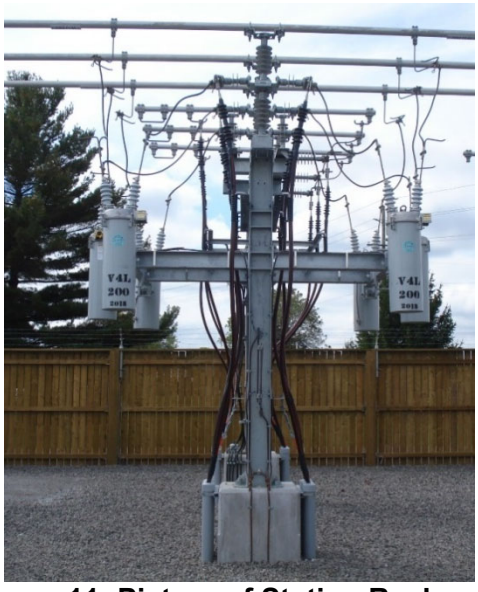


Figure 11: Picture of Station Reclosers

3.2.2.2.1.2 BREAKERS

Hydro One currently manages 261 distribution station circuit breakers across the Hydro One, Orillia and Peterborough Rate Zones (see example shown in Figure 12 below). Like reclosers, breakers are used to remove assets from service under fault conditions.



Figure 12: Picture of a Metalclad Breaker

3.2.2.2.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.2.2.2.1 ASSET DEMOGRAPHICS

3.2.2.2.2.1.1 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 9.

Table 9 - Recloser Count by Type (Number of Feeders)

Type	Hydro One Rate Zone	Orillia Rate Zone	Peterborough Rate Zone
Oil interrupter & hydraulic controlled	514	0	3
Oil interrupter & electronic controlled	31	0	0
Vacuum interrupter & hydraulic controlled	1275	0	0
Vacuum interrupter & electronic controlled	467	7	2

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.

3.2.2.2.2.1.2 BREAKERS

Hydro One has three types of breakers on its distribution system. The number of devices for each type is shown in Table 10.

Table 10 - Breaker Count by Type

Type	Hydro One Rate Zone	Orillia Rate Zone	Peterborough Rate Zone
Metalclad	147	29	73
SF6	1	0	0
Oil	0	0	11

Most metalclad 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.

Distribution Station breakers have an expected service life of 45 years. Figure 13 below shows the demographics of station breakers in the Hydro One Rate Zone. The current

average age of station breakers in the Hydro One Rate Zone is 51 years, and 72% (106 breakers) of the fleet are beyond their ESL.

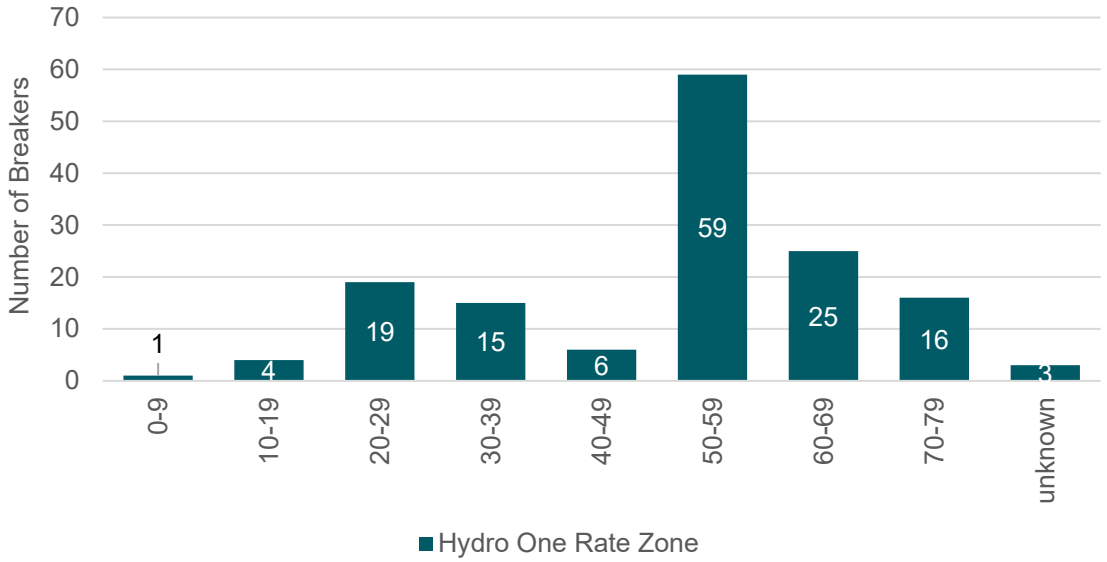


Figure 13: Demographics of the Distribution Station Breakers in Hydro One Rate Zone

Figure 14 below shows the demographics of station breakers in the Orillia Rate Zone. The current average age of station breakers in the Orillia Rate Zone is 37 years, and 45% (13 breakers) of the fleet are beyond their ESL.

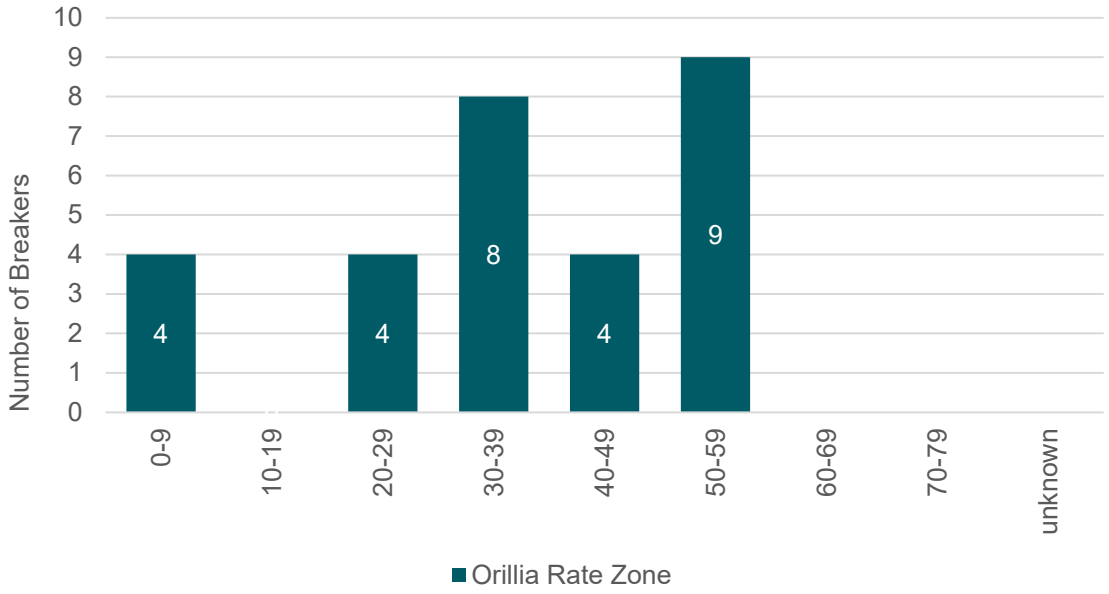


Figure 14: Demographics of the Distribution Station Breakers in Orillia Rate Zone

Figure 15 below shows the demographics of station breakers in the Peterborough Rate Zone. The current average age of station breakers in the Peterborough Rate Zone with known year of manufacture data is 59 years, and 100% (44 breakers) of the fleet with known year of manufacture are beyond their ESL.

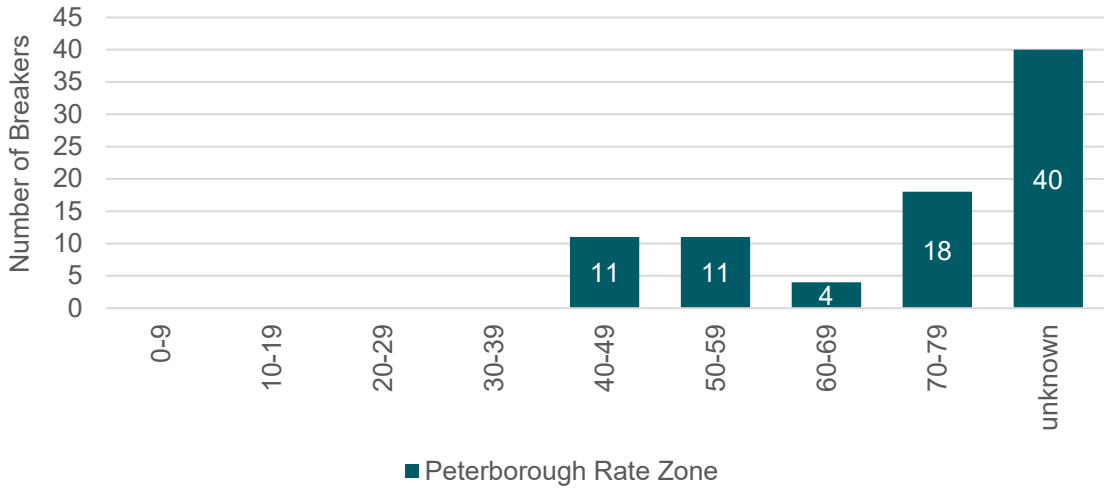


Figure 15: Demographics of the Distribution Station Breakers in Peterborough Rate Zone

Witness: Paul Ankrett; Aimee Oabel; David Paish

3.2.2.2.2.2 ASSET CONDITION

3.2.2.2.2.2.1 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 16 summarizes the condition of the station recloser population in the Hydro One Rate Zone. Replacement of Type L reclosers with Type V4L reclosers has helped reduce the number of poor condition reclosers.

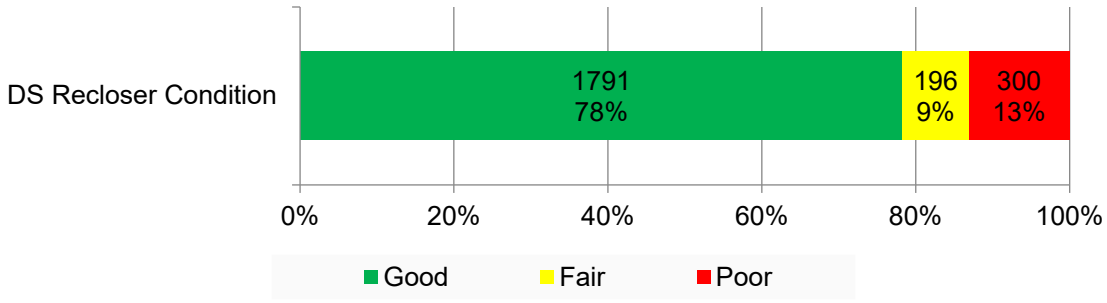


Figure 16: Condition of the Distribution Station Reclosers in Hydro One Rate Zone

All of the reclosers in the Orillia and Peterborough Rate Zones are currently in good condition.

3.2.2.2.2.2 BREAKERS

The condition of station breakers is primarily influenced by deficiencies that may impair their ability to operate as intended, specifically, their ability to open to clear system faults or to close to restore power. Given their critical role in system protection and restoration,

breaker performance is highly dependent on the functional integrity of numerous electromechanical components.

Station breakers include a range of mechanical and electrical elements that require regular inspection, maintenance, and monitoring to ensure reliable operation. For example, breaker operating mechanisms are dependent on proper lubrication; inadequate lubrication can lead to increased friction, accelerated wear, or mechanical failure. Similarly, breaker contacts experience wear over time as a function of the number of operations and the magnitude of fault current interrupted, necessitating periodic inspection and maintenance.

Additional components, including coils, contactors, motor commutators, brushes, relays, and auxiliary switches, are also subject to degradation and must be routinely assessed. These components require inspection, lubrication (where applicable), and condition monitoring to confirm they are functioning within acceptable parameters and to identify early signs of wear or failure.

A condition-based maintenance approach, supported by ongoing inspection and monitoring of these critical components, is essential to ensure breaker operability, mitigate failure risk, and maintain overall system reliability.

Figures 17, 18 and 19 summarize the condition of the station breaker population in the Hydro One, Orillia and Peterborough Rate Zones. Breakers identified as having “unknown” condition have not been removed from service in recent years for preventive maintenance that would allow Hydro One to assess their condition.

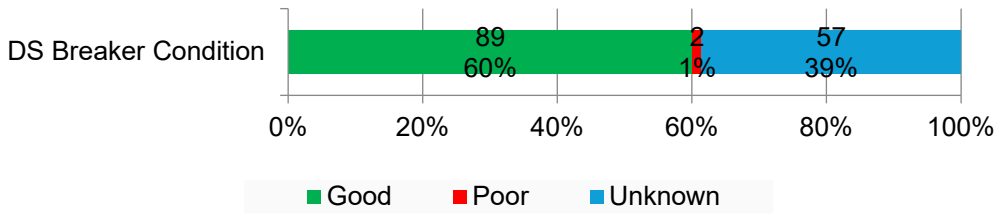


Figure 17: Condition of the Distribution Station Breakers in Hydro One Rate Zone

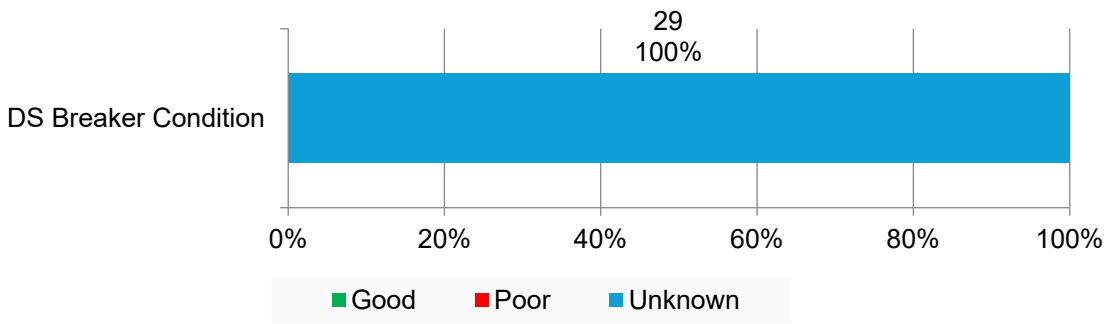


Figure 18: Condition of the Distribution Station Breakers in Orillia Rate Zone

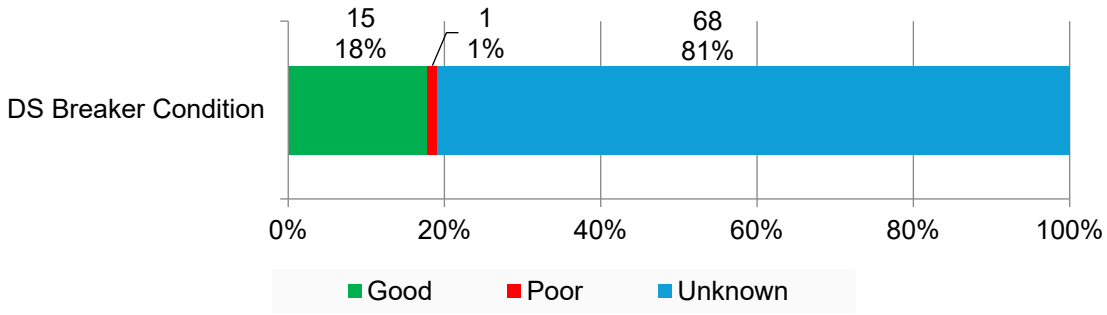


Figure 19: Condition of the Distribution Station Breakers in Peterborough Rate Zone

3.2.2.2.2.3 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 20 below represents the total annual number of DS recloser failures recorded each year from 2016 to 2025 in the Hydro One Rate Zone. From 2020 to 2025 there has been a reduction in the annual number of failures. The reduction in failures is primarily associated with the population of older Cooper Type “L” oil hydraulic reclosers that has

been replaced with newer Cooper Type “V4L” vacuum hydraulic reclosers which fail less frequently.

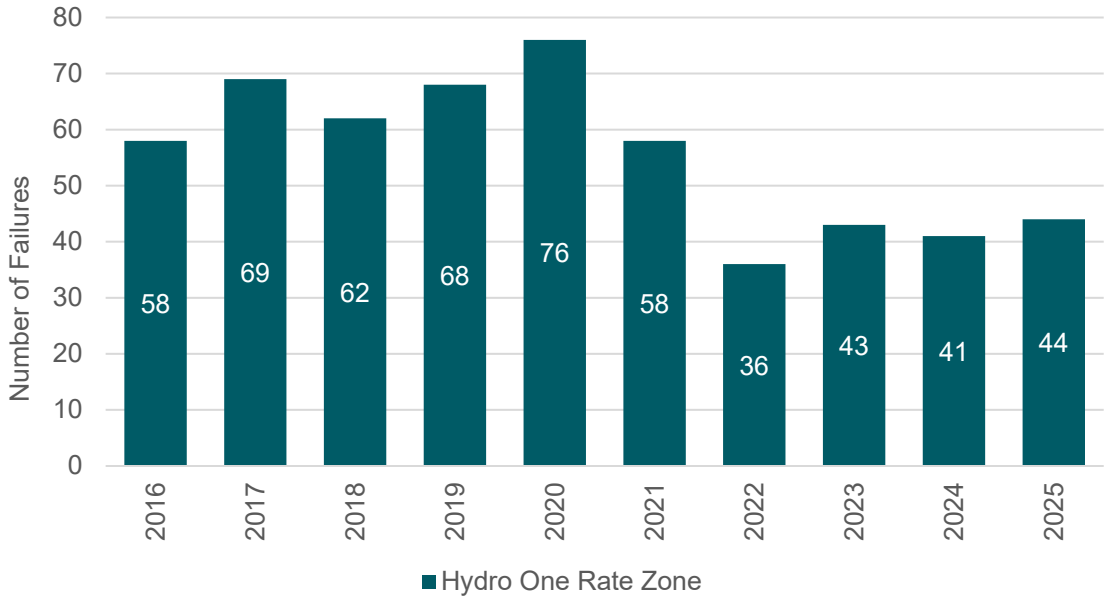


Figure 20: Distribution Station Recloser Failures in Hydro One Rate Zone

No recloser failures have been recorded in the Orillia and Peterborough Rate Zones since their acquisition in 2021.

Figure 21 below represents the annual number of DS breaker failures recorded each year from 2016 to 2025 in the Hydro One Rate Zone.

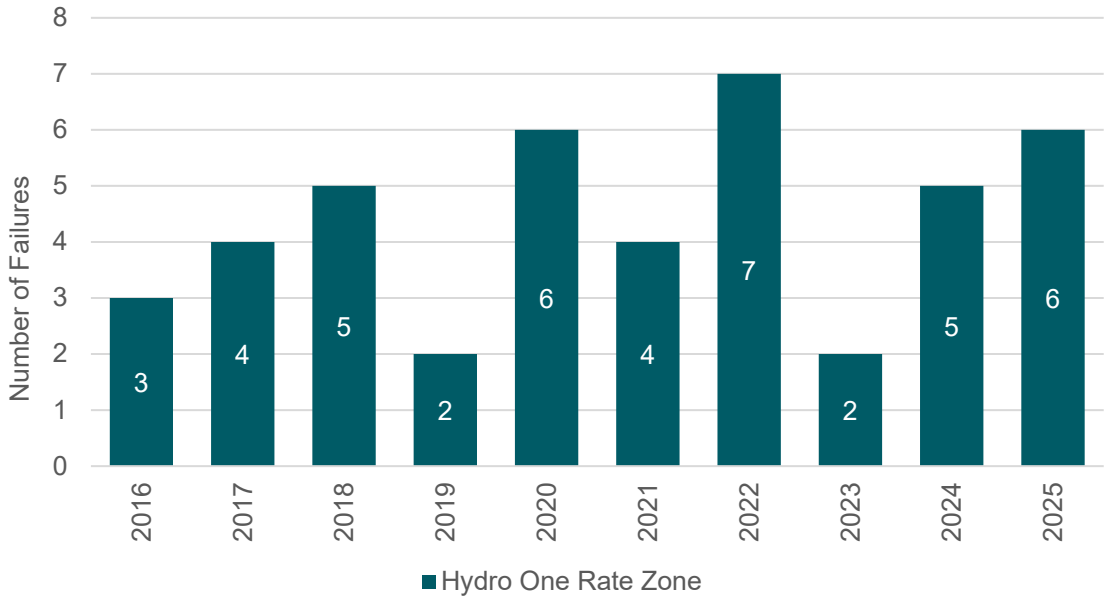


Figure 21: Distribution Station Breaker Failures in Hydro One Rate Zone

Figure 22 below represents the annual number of DS breaker failures recorded each year from 2021 to 2025 in the Orillia Rate Zone.

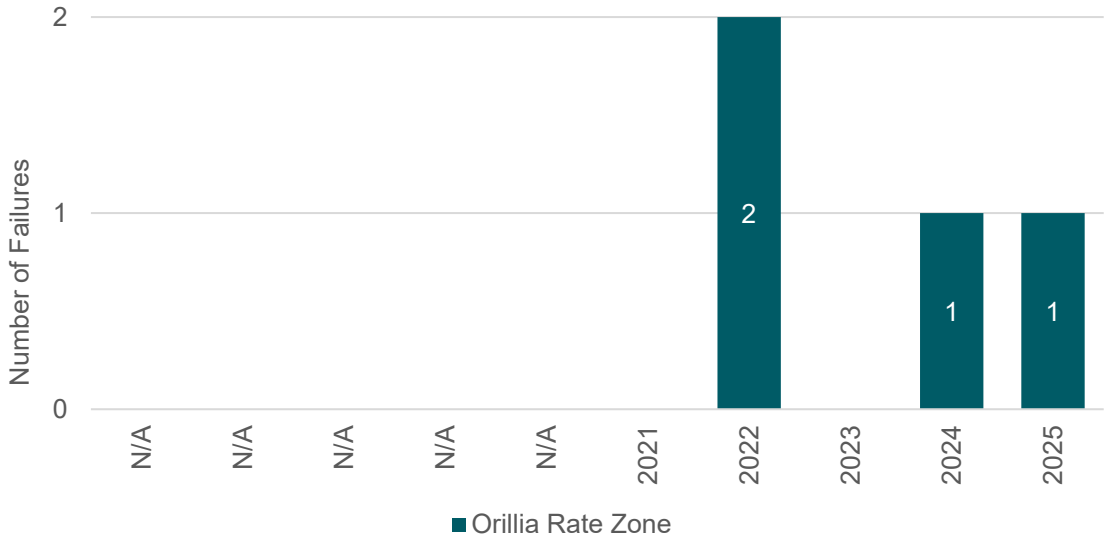


Figure 22: Distribution Station Breaker Failures in Orillia Rate Zone

Figure 23 below represents the annual number of DS breaker failures recorded each year from 2021 to 2025 in the Peterborough Rate Zone.

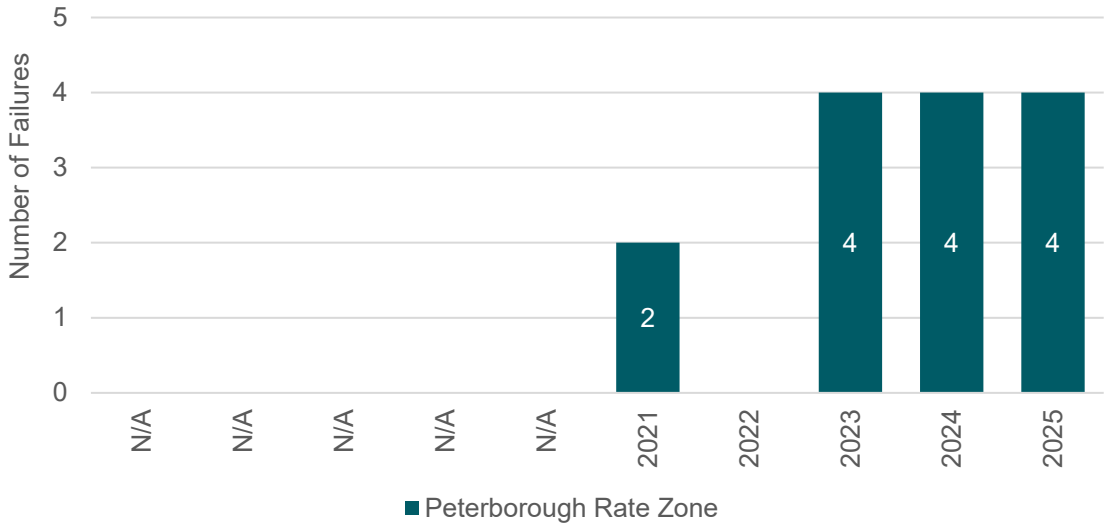


Figure 23: Distribution Station Breaker Failures in Peterborough Rate Zone

3.2.2.2.3 LIFECYCLE STRATEGY

3.2.2.2.3.1 INSPECTION & MAINTENANCE PRACTICES

3.2.2.2.3.1.1 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 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's recommended number of operations since they were last inspected. Stations also receive an 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 recloser is further discussed below.

When oil interrupter hydraulic controlled reclosers require maintenance, model types including Cooper Type “D”, “DV” and “W” 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. However, Cooper Type “L”, “E”, “4E”, and “4H” reclosers are upgraded to Cooper Type “V4L”, “V4E” and “V4H” vacuum interrupter hydraulic reclosers when they require maintenance. The “V4L”, “V4E” and “V4H” vacuum reclosers have similar dimensions to the “L”, “E”, “4E” and “4H” reclosers and the replacement is efficient and cost effective.

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. When these reclosers fail, they are replaced “like-for-like” with the same model if one is available in inventory. If none are available in inventory, these reclosers are replaced with new vacuum interrupter electronic controlled reclosers.

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”, “E”, “4E”, and “4H” 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 6kA 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 6kA is required.

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

3.2.2.2.3.1.2 BREAKERS

Hydro One's strategy for the station breaker population is to continue to maintain the fleet (through preventive maintenance) 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.

Breakers must be removed from service and inspected to monitor their condition and maintain them. 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.

3.2.2.2.3.2 REPLACEMENT & REFURBISHMENT

3.2.2.2.3.2.1 RECLOSERS

Oil hydraulic reclosers including Cooper Types "L", "E", "4E" and "4H" are replaced with vacuum hydraulic reclosers when their counter operations are reached. Other oil hydraulic reclosers including Cooper Types "D", "DV" and "W" 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, 517 feeders are equipped with oil interrupter hydraulic controlled reclosers. Of these, approximately 251 or approximately 49% are Cooper Type “L”, “E”, “4E” or “4H”. The strategy for these reclosers is to replace them with vacuum interrupter hydraulic controlled reclosers as opposed to maintaining them when their manufacturer recommended number of operations before maintenance has been reached. 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 are 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 reclosers 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 reclosers will be replaced with vacuum hydraulic reclosers or vacuum electronic reclosers, depending on system needs and potential benefits.

3.2.2.2.3.2.2 BREAKERS

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 if replacement parts can be obtained.

Replacement – Breakers & Reclosers

During planned station refurbishment 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 Distribution Station Renewal investments (DSP Section 3.11, D-SR-04).

3.2.2.3 STATION SWITCHES & FUSES

3.2.2.3.1 ASSET DESCRIPTION / PURPOSE

Station switches enable the isolation of equipment such as transformers, breakers or reclosers, 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 24: Picture of Station Switch and Fuse Combination

3.2.2.3.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.2.3.2.1 ASSET DEMOGRAPHICS

Hydro One currently manages 2,653 three-phase switches and 1,852 three-phase fuses installed at distribution stations within the Hydro One, Orillia and Peterborough Rate Zones. The number of switches in the Hydro One, Orillia and Peterborough Rate Zones are shown in Table 11 below:

Table 11 - Switches by Voltage

Primary Voltage Level	Hydro One Rate Zone	Orillia Rate Zone	Peterborough Rate Zone
230kV	2	0	0
115kV	154	0	0
44kV	856	12	33
27.6kV	493	0	4
< 27.6kV	1,007	24	68

The number of fuses in Hydro One, Orillia and Peterborough Rate Zones are shown in Table 12 below:

Table 12 - Fuses by Voltage

Primary Voltage Level	Hydro One Rate Zone	Orillia Rate Zone	Peterborough Rate Zone
230kV	0	0	0
115kV	94	0	0
44kV	727	11	14
27.6kV	207	0	0
< 27.6kV	768	22	9

3.2.2.3.2.2 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. Degradation from aging is contributing to increasing number of poor condition switches.

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. Poor condition fuses are generally replaced within maintenance programs.

Figures 25 and 26 summarize the condition of the station switches and fuses in the Hydro One Rate Zone.

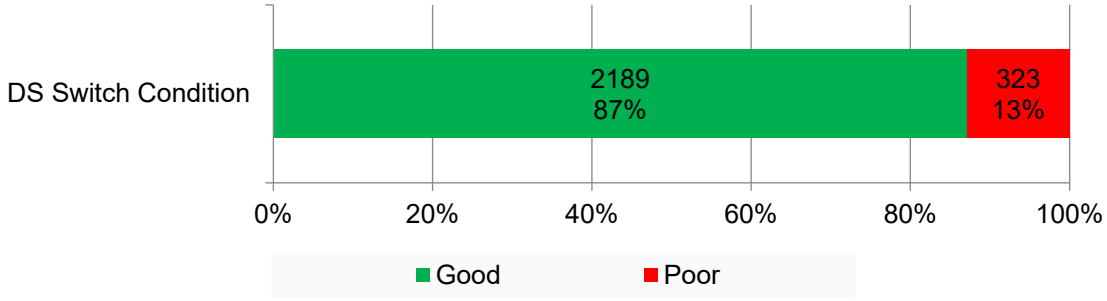


Figure 25: Condition of the Distribution Station Switches in Hydro One Rate Zone

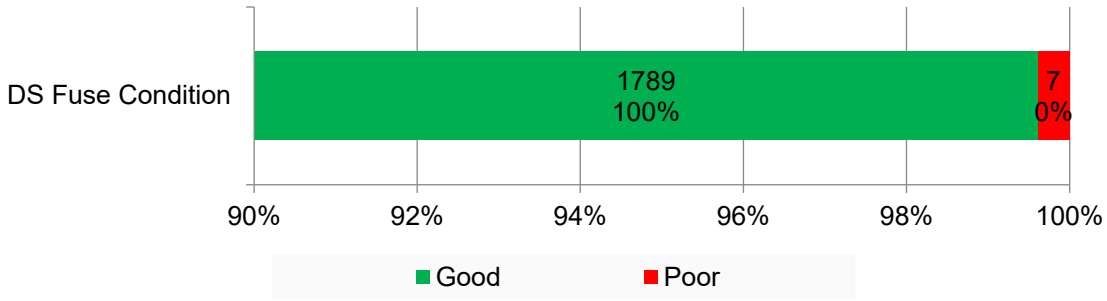


Figure 26: Condition of the Distribution Station Fuses in Hydro One Rate Zone

All switches and fuses in the Orillia and Peterborough Rate Zones are currently identified as in good condition.

3.2.2.3.2.3 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 27 below represents the annual number of DS switch failures recorded from 2016 to 2025 in the Hydro One Rate Zone.

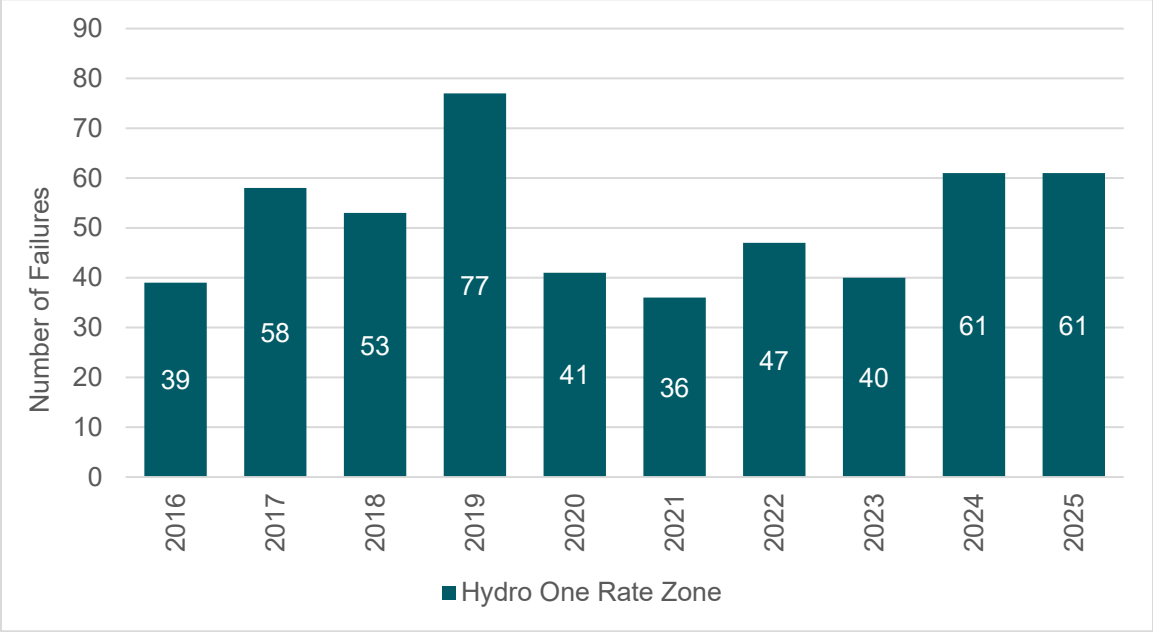


Figure 27: Distribution Station Switch Failures in Hydro One Rate Zone

No switch failures were observed in the Orillia and Peterborough Rate Zones from 2021 to 2025.

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.

3.2.2.3.3 LIFECYCLE STRATEGY

3.2.2.3.3.1 INSPECTION & MAINTENANCE PRACTICES

Hydro One visually inspects switches during routine station inspections twice per year 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 twice a year 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.

3.2.2.3.3.2 REPLACEMENT & REFURBISHMENT

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

3.2.2.4.1 ASSET DESCRIPTION / PURPOSE

Hydro One currently has a fleet of 33 MUSs. MUSs contain components similar to a distribution station but are mounted on a trailer so that a unit can be transported and temporarily connected to a station (see example shown in Figure 28). There are no acquired MUSs from the Orillia and Peterborough Rate Zones.

The MUS fleet is primarily utilized for:

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

MUS availability is therefore important for both emergency response and for Hydro One's ability to execute planned station maintenance and renewal work.



Figure 28: 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. It takes approximately 7 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 replacement requires long lead-time activities (e.g., rental or procurement of adjacent land for a crane to access the failed transformer).

3.2.2.4.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.2.4.2.1 ASSET DEMOGRAPHICS

MUSs include two key components with distinct lifecycle characteristics: the transformer and the trailer.

The age distribution for these two components of the MUSs is shown in Figures 29 and 30.

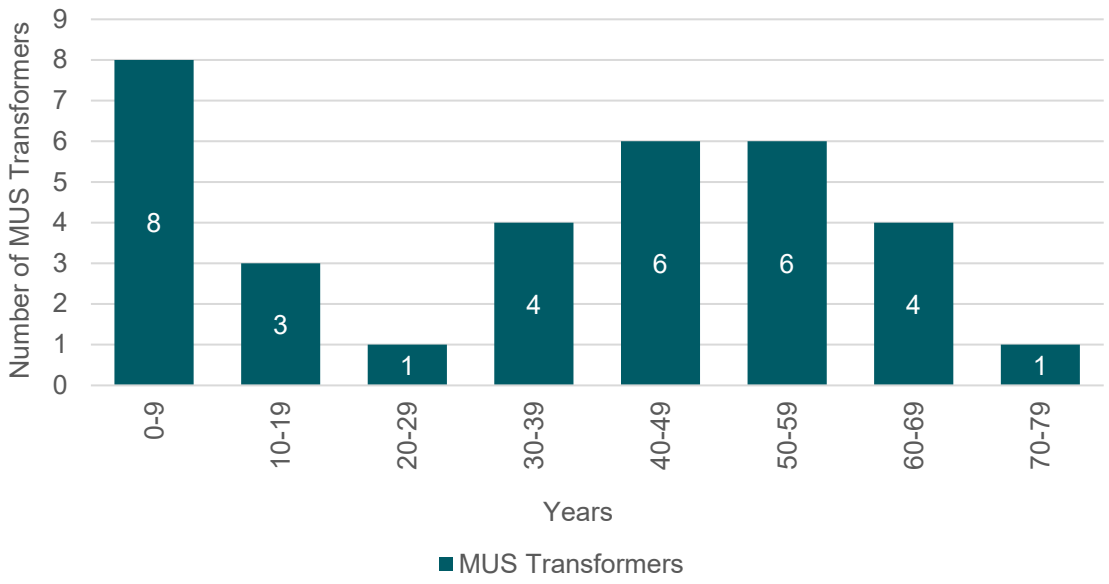


Figure 29: Demographics of the Mobile Unit Substation Transformers

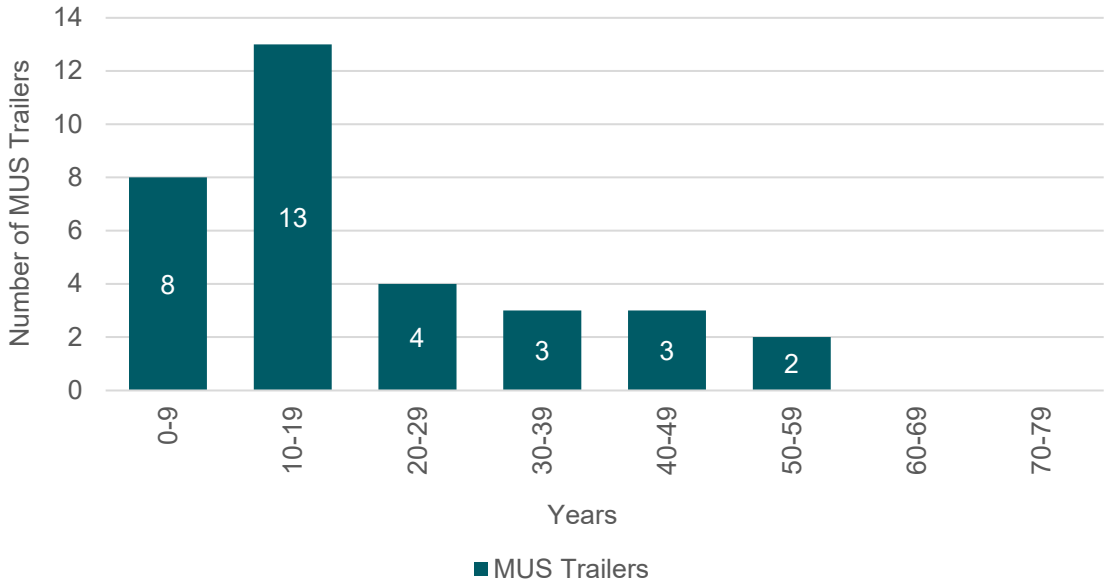


Figure 30: Demographics of the Mobile Unit Substation Trailers

The average age of the MUS transformers is 35 years and currently 48% of the MUS transformers are beyond their ESL of 40 years. The average age of the MUS trailers is 21 years, and currently 24% of the MUS trailers are beyond their ESL of 25 years. These demographics indicate a mature MUS population. However, age alone does not determine whether an MUS requires replacement. Condition, repairability and the ability of the unit to continue performing its operational function are the principal considerations.

3.2.2.4.2.2 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, 24% of the MUS transformers and 18% of the MUS trailers are in poor condition, as shown in Figures 31 and 32.

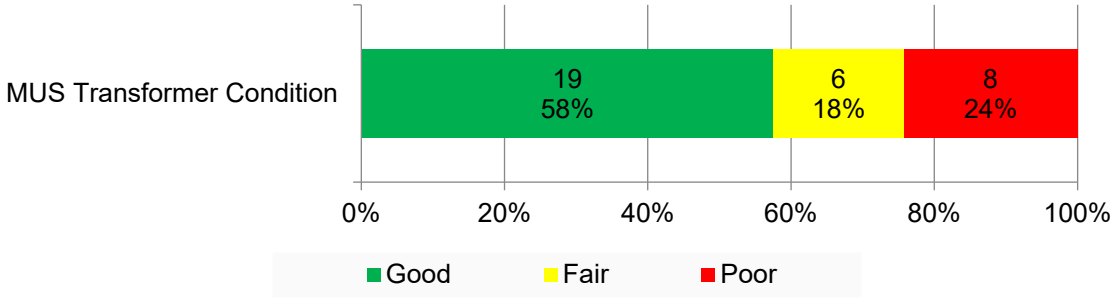


Figure 31: MUS Transformer Condition

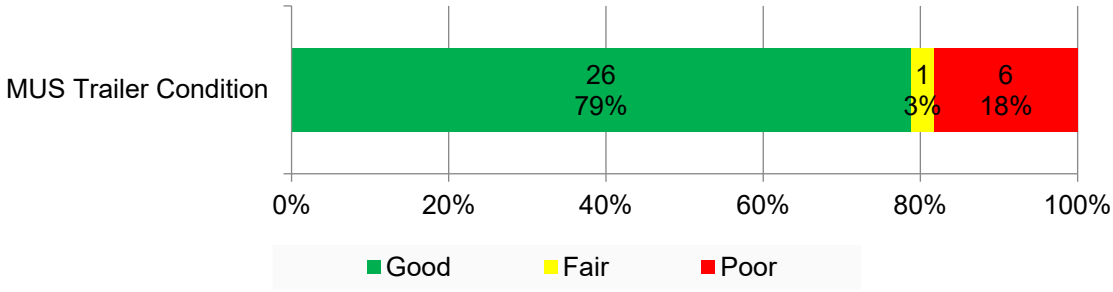


Figure 32: MUS Trailer Condition

Poor condition MUS components require lifecycle intervention because deterioration can affect the reliability and availability of the unit. Because each unavailable MUS reduces the fleet available to respond to station failures or support planned work, the condition of individual units must also be considered in the context of overall fleet availability.

3.2.2.4.2.3 ASSET PERFORMANCE

From 2016 to 2025, five MUSs have been retired, of which three have been replaced.

MUS #26 experienced a transformer failure in 2018 and was retired at that time. It was replaced by a new MUS #45 in 2019.

In 2020, the MUS #21 transformer windings were wet. At this time the transformer was 59 years old. Hydro One decided to retire MUS #21 after attempts to source a larger

replacement transformer equipped with an under-load tap-changer were unsuccessful. This MUS was replaced by MUS #48 in 2022.

In 2023, the MUS #04 transformer windings were wet. Following an unsuccessful attempt to dry-out the transformer, Hydro One made the decision to retire MUS #04. This MUS will be replaced by new MUS #52 on order, in 2027.

The MUS #23 transformer suffered a failure in 2024, and the MUS was retired at that time. This MUS was replaced by MUS #51 in 2025.

The MUS #42 transformer suffered a failure in 2025, and the MUS was retired at that time. This MUS will be replaced by new MUS #53 planned for 2029 delivery.

The failure and retirement history demonstrate the importance of managing both the condition of individual MUSs and the availability of the overall fleet. When an MUS is retired or committed to an extended station deployment, it is unavailable for other emergency failures, planned corrective maintenance or capital work.

The duration of individual deployments can materially affect fleet availability. For a planned station-transformer replacement, engineering, procurement and other preparatory activities can generally be completed before the MUS is installed, and the MUS may be required for approximately five months. By contrast, following an unplanned transformer failure requiring replacement, these activities begin after the failure occurs and the MUS can remain committed to the station for more than 12 months. Extended deployments reduce the number of units available to respond to other station contingencies and support planned work.

3.2.2.4.3 LIFECYCLE STRATEGY

Hydro One's asset strategy for the MUS fleet over the 2028-2032 planning period is as follows:

- Replace MUSs that have been retired due to MUS transformer failure

- Replace MUSs that will need to be retired due to condition of the transformer and/or trailer
- Procure nine additional MUSs to enable more capital projects and 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. DSP Section 3.11, D-SR-02 addresses this need by replacing 3 MUSs currently in poor condition and adding 9 additional MUSs to the fleet in the 2028-2032 forecast period.

3.2.2.4.3.1 INSPECTION & MAINTENANCE PRACTICES

MUS trailers require an Ontario Ministry of Transportation (MTO) annual inspection certificate and undergo a mandatory annual inspection of the trailer 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 inspection and maintenance of all electrical components every two years. 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 (two year) frequency.

3.2.2.4.3.2 REPLACEMENT & REFURBISHMENT

MUS transformers that are in poor condition based on inspections or oil sample results are considered for repair or replacement. Where the identified deterioration can be technically and economically corrected and sufficient remaining service life can be retained, Hydro One repairs the transformer and continues to operate the MUS. Where the nature or extent of deterioration makes further repair impractical or uneconomic, the MUS is considered for replacement.

Age informs this assessment but does not independently determine the intervention. 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 provide limited additional service life, which would not be economical as more components are expected to break and need to be further addressed.

When MUS transformers require replacement, the preferred transformer specifications include a minimum of 7.5MVA for 27.6kV primary voltage MUSs, minimum 10MVA for 44kV primary voltage MUSs, and minimum 15MVA for 115kV primary voltage MUSs. Also, MUS transformers equipped with “Under-Load Tap-Changers” (ULTC) are preferred over those which are not equipped with an ULTC. These specifications allow MUSs to be suitable for most Hydro One DS applications.

Hydro One’s recent approach has been to replace failed MUS transformers through the procurement of complete, new MUS units, to incorporate the integration of standardized transformer ratings while ensuring compatibility with current design and operational requirements. New MUS units incorporate modern protection and control technologies, including electronic reclosers and advanced controllers. These enhancements improve feeder protection performance and provide enhanced protection for the MUS transformer itself, thereby reducing the risk of failure and supporting more reliable service restoration during outage events.

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 the MUS trailer is in poor condition and determined to be in need of replacement, these MUSs will be retired and replaced with a new MUS.

Overall, Hydro One’s MUS lifecycle strategy combines repair of serviceable units with condition-driven replacement of deteriorated units and management of fleet availability.

For the 2028-2032 period, maintaining an appropriately sized and capable MUS fleet is increasingly important because the fleet must support both station contingencies and the higher level of planned station renewal and maintenance work.

3.2.2.5 OTHER STATION ASSETS

3.2.2.5.1 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.
- *Buildings* can be used to contain LV station equipment such as metalclad breakers and relays in urban stations. In some cases, the buildings can also contain the stepdown transformer and HV station equipment.
- *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.

3.2.2.5.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.2.5.2.1 ASSET DEMOGRAPHICS

The approximate counts of these other station components are shown in Table 13 below:

Table 13 - Other Distribution Station Components

Station Component	Hydro One Rate Zone	Orillia Rate Zone	Peterborough Rate Zone
Station Structures	2,116	7	4
Buildings	82	9	14
MUS Structures	819	0	0
Fences	1001	10	19
Station Grounding Systems	985	9	15
Station Service Transformers	675	9	3
Insulators	unknown	unknown	unknown
Bus Work	1,082	9	15
Spill containment systems	99	0	0
Protection Relays	143	21	60
IEDs	598	16	14

3.2.2.5.2.2 ASSET CONDITION

The condition profile of *station structures* in the Hydro One Rate Zone is shown in Figure 33 below:

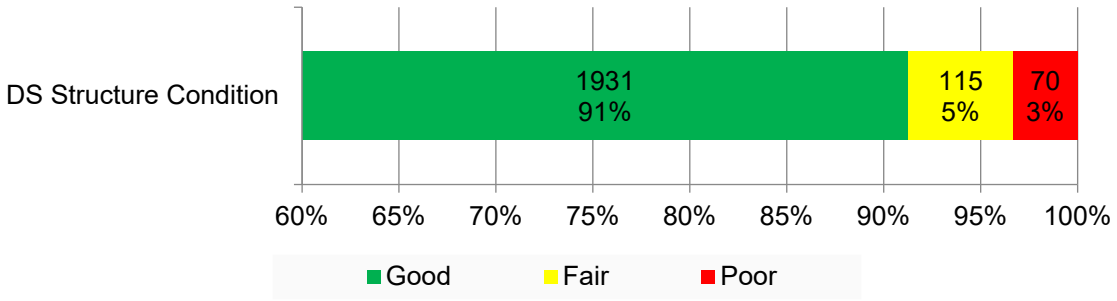


Figure 33: DS Station Structure Condition in Hydro One Rate Zone

The station structures in the Orillia Rate Zone and Peterborough Rate Zones are currently in good 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).

Hydro One does not maintain condition profile information for station buildings in the Hydro One, Orillia and Peterborough Rate Zones. When deficiencies are identified such as leaking roofs, defective doors or defective windows, they are addressed.

The condition profile of *MUS structures* in the Hydro One Rate Zone is shown in Figure 34 below:

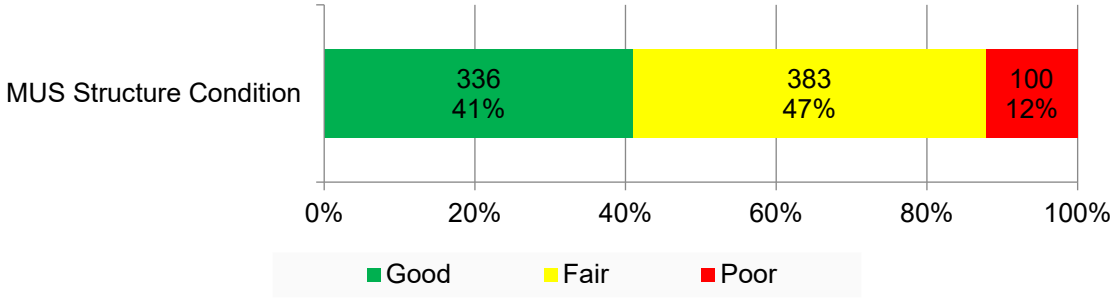


Figure 34: MUS Structure Condition in Hydro One Rate Zone

There are currently no MUS structures in the Orillia and Peterborough Rate Zones.

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* in the Hydro One Rate Zone is shown in Figure 35 below:

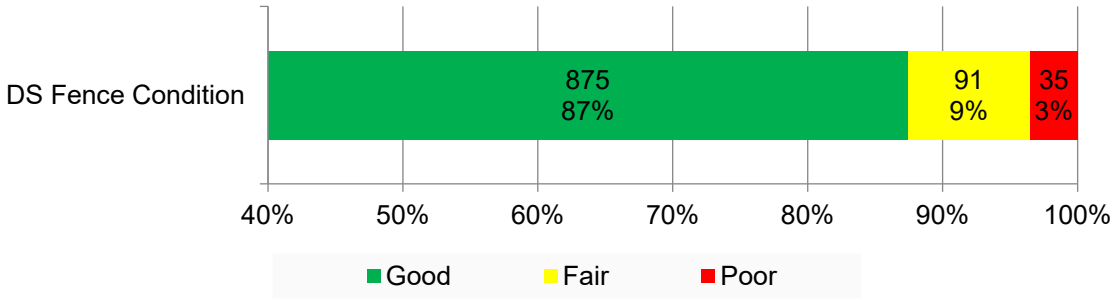


Figure 35: DS Station Fence Condition

All fences in the Orillia and Peterborough Rate Zones are currently identified as in good condition.

Poor condition fences are typically replaced under station refurbishment projects (DSP Section 3.11, 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* in the Hydro One Rate Zone is shown in Figure 36:

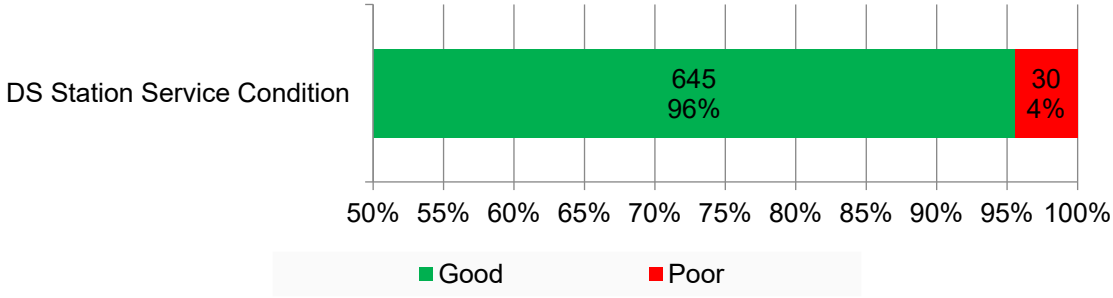


Figure 36: DS Station Service Condition

In the Orillia Rate Zone, one station service transformer has been identified as in poor condition, with all others in good condition. In the Peterborough Rate Zone, all station service transformers have been identified as in good 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* in the Hydro One Rate Zone is shown in Figure 37 below:

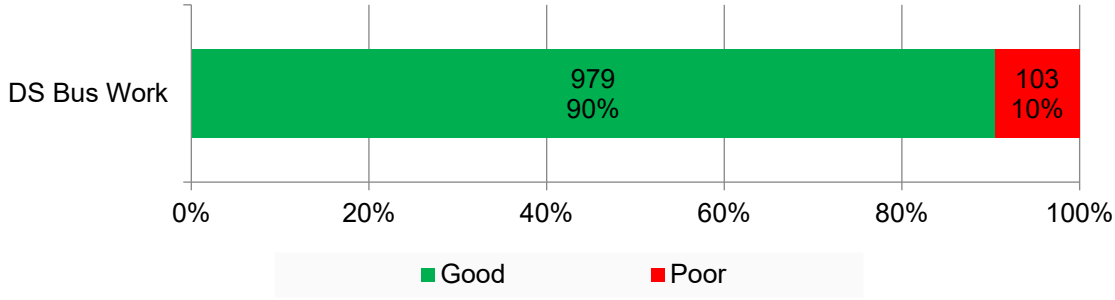


Figure 37: DS Station Bus Condition

All station bus in the Orillia Rate Zone and Peterborough Rate Zone are currently identified as in good 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).

All spill containment systems in the Hydro One Rate Zone are currently identified as in good condition. There are no spill containment systems in the Orillia and Peterborough Rate Zones. Poor condition spill containment systems are typically repaired under corrective maintenance programs.

Protection Relays and 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.

3.2.2.5.3 LIFECYCLE STRATEGY

3.2.2.5.3.1 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.

3.2.2.5.3.2 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 approximately 126,000 circuit kilometers of distribution lines, which are critical to the reliable delivery of power to over 1.5 million distribution customers across the province. Distribution line assets include:

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

3.2.3.1 POLES

3.2.3.1.1 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. As outlined in pole counts in Table 14 below, 99.1% of the poles are wood poles, and 0.9% are steel, composite, or concrete poles. In addition, Hydro One maintains and operates overhead lines that are supported by approximately 400,000 poles owned by joint use partners.

Table 14 - Hydro One Owned Poles by Material Type

Material	Hydro One RZ	Orillia RZ	Peterborough RZ
Composite	6,517	8	
Concrete	2,257	60	378
Steel	6,199	4	2
Wood	1,615,413	4,132	8,202
Total	**1,630,386**	**4,204**	**8,582**

Wood is currently the most cost-effective material for the majority of pole applications. In specific situations, such as where environmental consideration or enhanced durability is required, a composite pole may need to be used[2]. Composite poles, however, are generally more expensive than wood for all sizes on the distribution system. 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.

Over time, wood poles are subject to natural deterioration due to environmental exposure.

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 from woodpeckers, insects and other sources, can also reduce pole structural integrity and service life.

To mitigate natural deterioration over time, poles are initially treated with Chromated Copper Arsenate (CCA) in advance of installation. This preservative penetrates the outer portion of the pole and protects the wood from rot and fungal deterioration. Figure 38 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 untreated heartwood.

[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.



Figure 38: Treated Wood Pole Cross Section

3.2.3.1.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.3.1.2.1 ASSET DEMOGRAPHICS

Figure 39 shows the current demographics of the Hydro One owned pole population within the Hydro One Rate Zone. The average age of poles is 43.7 years. Poles generally have an Expected Service Life of 60 years. There are currently 451,764 poles (28%) that are 60 years of age or older. In the absence of pole replacements, the number of poles 60 years or older would increase to 576,000 poles (35%) by 2032.

The pole population has become materially more mature since 2020. The average age of Hydro One poles increased from 40.2 years to 43.7 years by 2025, while the proportion of poles aged 60 years or older increased from 23% to 28%. Age does not itself determine whether an individual pole requires replacement, however, increasing mature population expands the number of poles exposed to age-related deterioration from which condition-driven renewal needs may emerge.

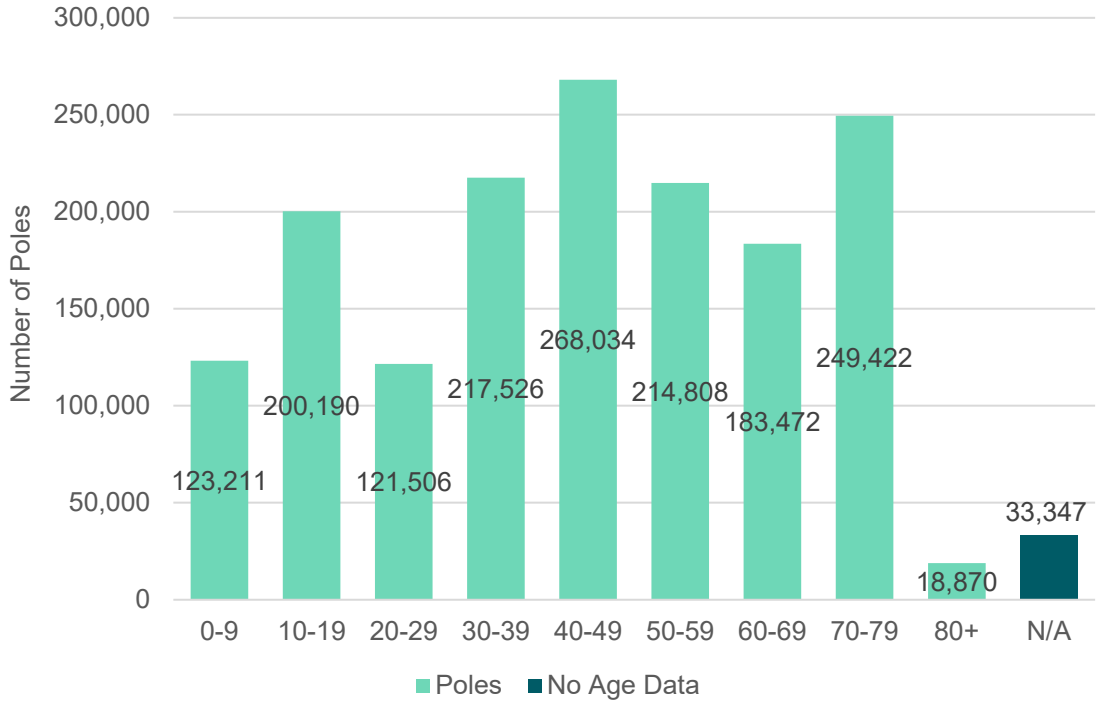


Figure 39: Demographics of Hydro One Owned Distribution Poles in Hydro One Rate Zone

Figure 40 shows the current demographics of the Hydro One owned pole population within the Orillia Rate Zone. The average age of poles is 36.0 years. There are currently 499 poles (12%) that are 60 years of age or older. In the absence of pole replacements, the number of poles 60 years or older would increase to 833 poles (20%) by 2032.

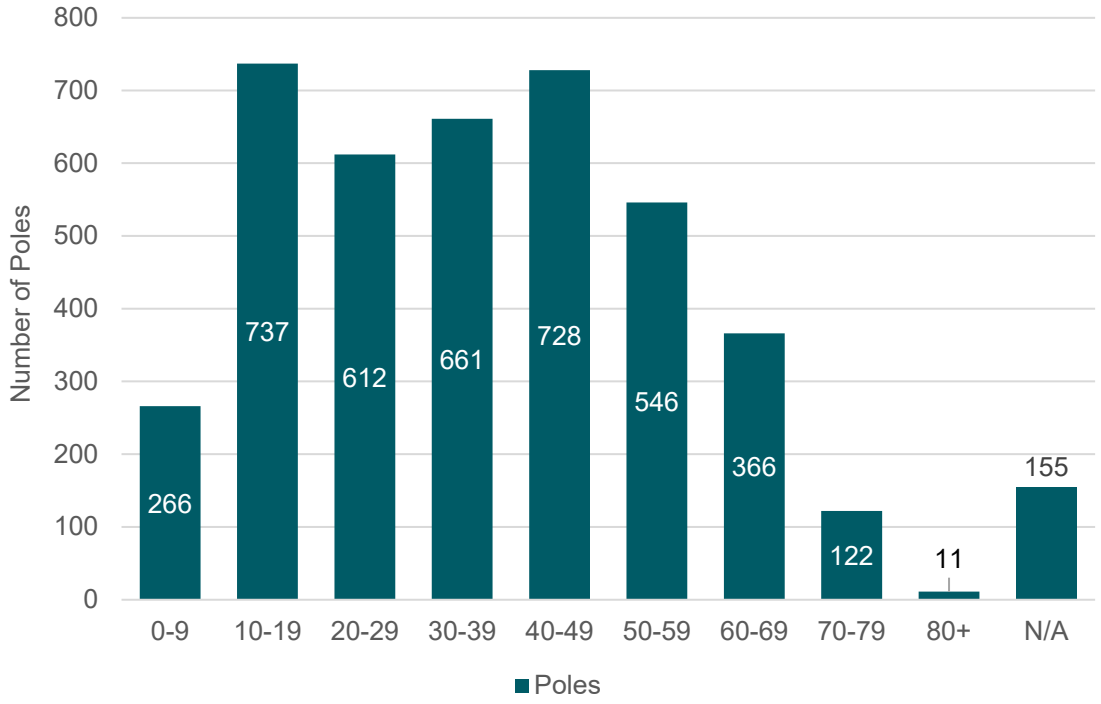


Figure 40: Demographics of Hydro One Owned Distribution Poles in Orillia Rate Zone

Figure 41 shows the current demographics of the Hydro One owned pole population within the Peterborough Rate Zone. The average age of poles is 37.4 years. There are currently 1,053 poles (12%) that are 60 years of age or older. In the absence of pole replacements, the number of poles 60 years or older would increase to 1,469 poles (17%) by 2032.

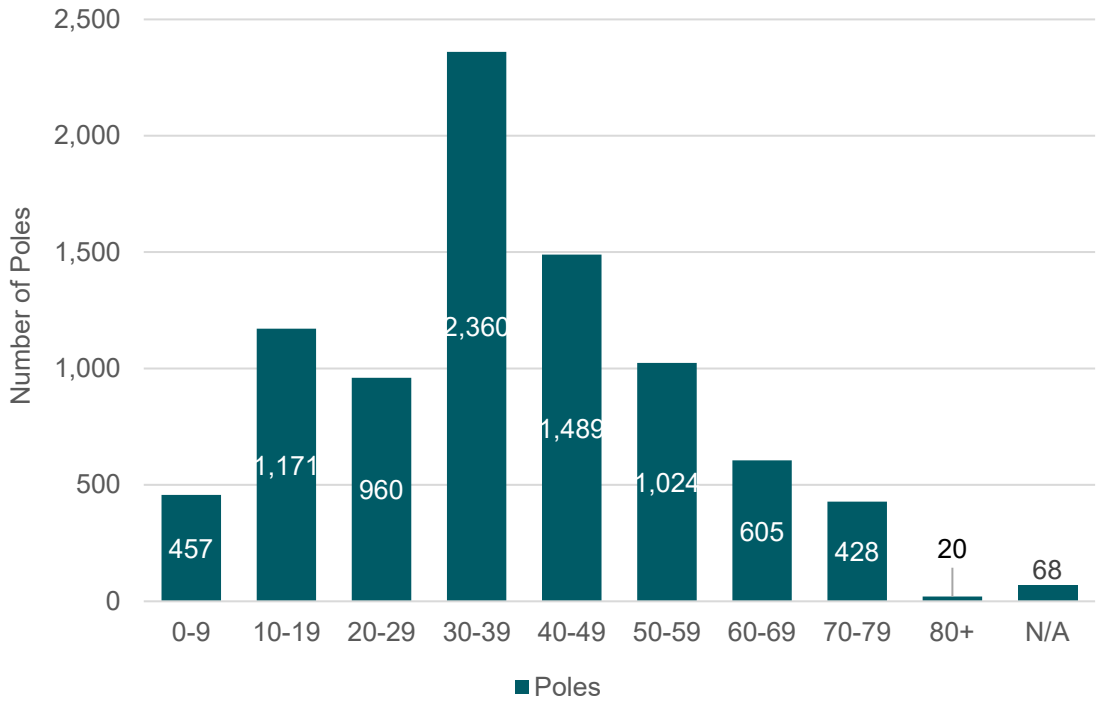


Figure 41: Demographics of Hydro One Owned Distribution Poles in Peterborough Rate Zone

3.2.3.1.2.1 ASSET CONDITION

Pole condition is assessed through regular inspections and the wood pole test and treat programs. Visual inspections identify deficiencies such as woodpecker damage, surface rot, mechanical damage, leaning and other visible deterioration. Pole testing provides additional quantitative information on structural condition, including remaining shell thickness and structural strength. Poles with deficiencies that result in a poor condition assessment require lifecycle intervention through refurbishment or replacement, depending on the nature and extent of deterioration.

Figures 42, 43 and 44 below provide examples of pole defects that require remedial action.



Figure 42: Woodpecker Damage



Figure 43: Ground Line Surface Rot

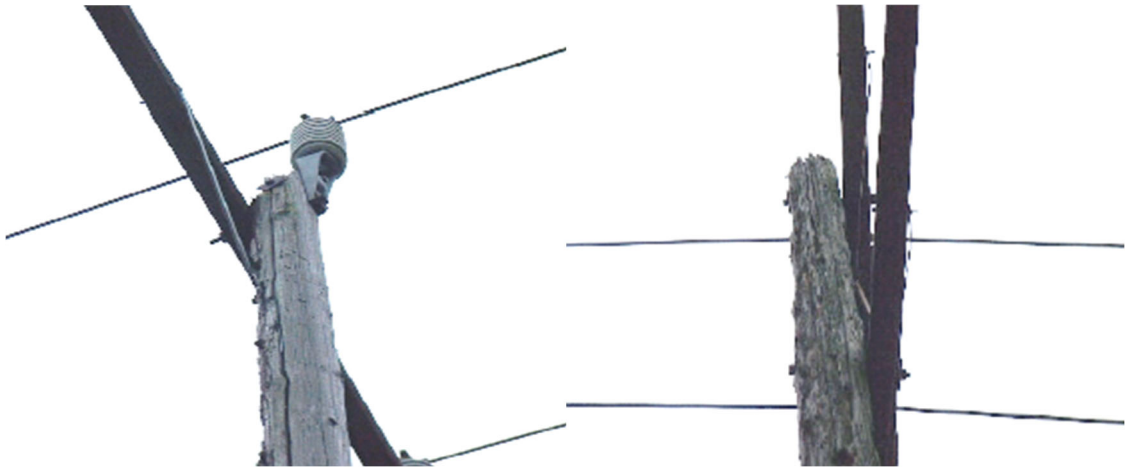


Figure 44: Pole Top Damage

Figure 45 shows the breakdown of the condition ratings of Hydro One distribution poles within the Hydro One Rate Zone as determined based on observed defects or testing results. There are approximately 99,000 poles that are in poor condition that require replacement or refurbishment. This represents an increase of 20,000 poles, or approximately 25%, from the 79,000 poor condition poles identified in 2020. Over the same period, the average age of the population increased and the proportion of poles aged 60 years and older increased from 23% to 28%. The growth in the poor condition population, together with the continued aging of the fleet, demonstrates increasing condition-driven renewal requirements.

Pole inspections have identified a growing number of poor condition poles, increasing from approximately 10,000 annually in 2021 to approximately 15,000 annually based on recent inspection results. Extrapolating this trend, the poor condition pole population is forecast to increase significantly to over 200,000 by 2032.

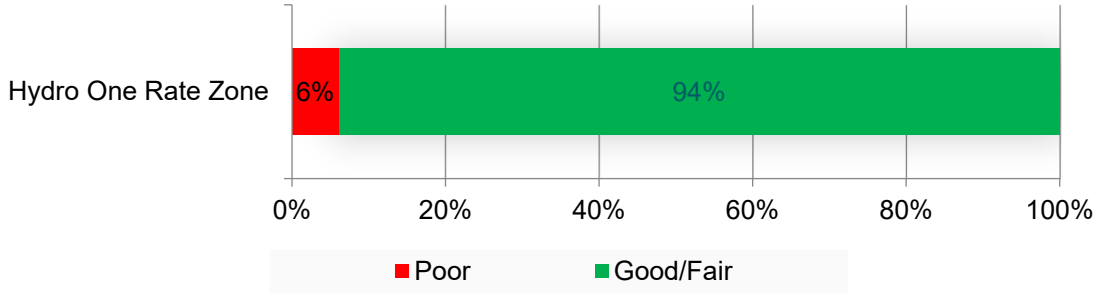


Figure 45: Hydro One Rate Zone Pole Condition

Figure 46 shows the breakdown of the condition ratings of Hydro One distribution poles within the Orillia Rate Zone as determined based on observed defects or testing results. There are approximately 118 poles that are in poor condition and require replacement or refurbishment.

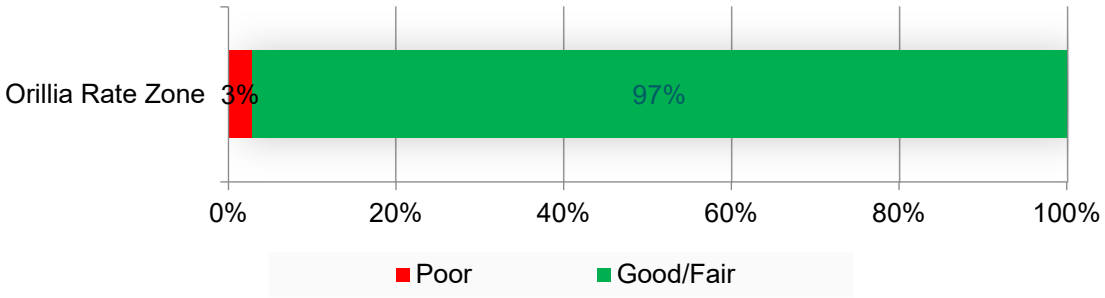


Figure 46: Orillia Rate Zone Pole Condition

Figure 47 shows the breakdown of the condition ratings of Hydro One distribution poles within the Peterborough Rate Zone as determined based on observed defects or testing results. There are approximately 320 poles that are in poor condition and require replacement or refurbishment.

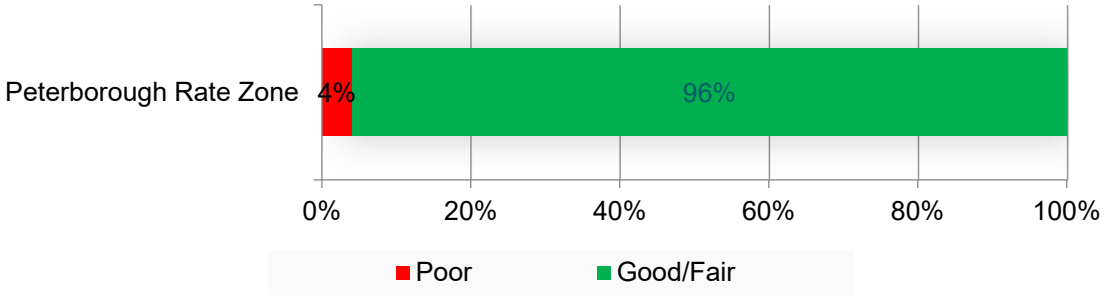


Figure 47: Peterborough Rate Zone Pole Condition

3.2.3.1.2.3 ASSET PERFORMANCE

Due to the predominantly radial nature of Hydro One's distribution system, structural pole failures can directly result in customer interruptions because service generally cannot be restored until the failed pole and associated equipment are repaired or replaced.

As described above, Hydro One's pole population is aging and the number of poles identified in poor condition has increased. Reliability performance is a lagging indicator of this accumulated asset deterioration: deterioration can develop over time before a pole ultimately fails and results in a customer interruption. As the population ages and more poles deteriorate into poor condition, the number of poles with elevated failure risk increases, placing increasing pressure on reliability performance.

Figure 48 below shows the number of interruptions attributed to pole failures, excluding Force Majeure events, from 2016 to 2025. Pole related interruptions have increased materially over this period, from 234 in 2016 to 570 in 2025. Average annual pole-related interruptions increased from 290 during 2016-2020 to 495 during 2021-2025, an increase of approximately 70%.

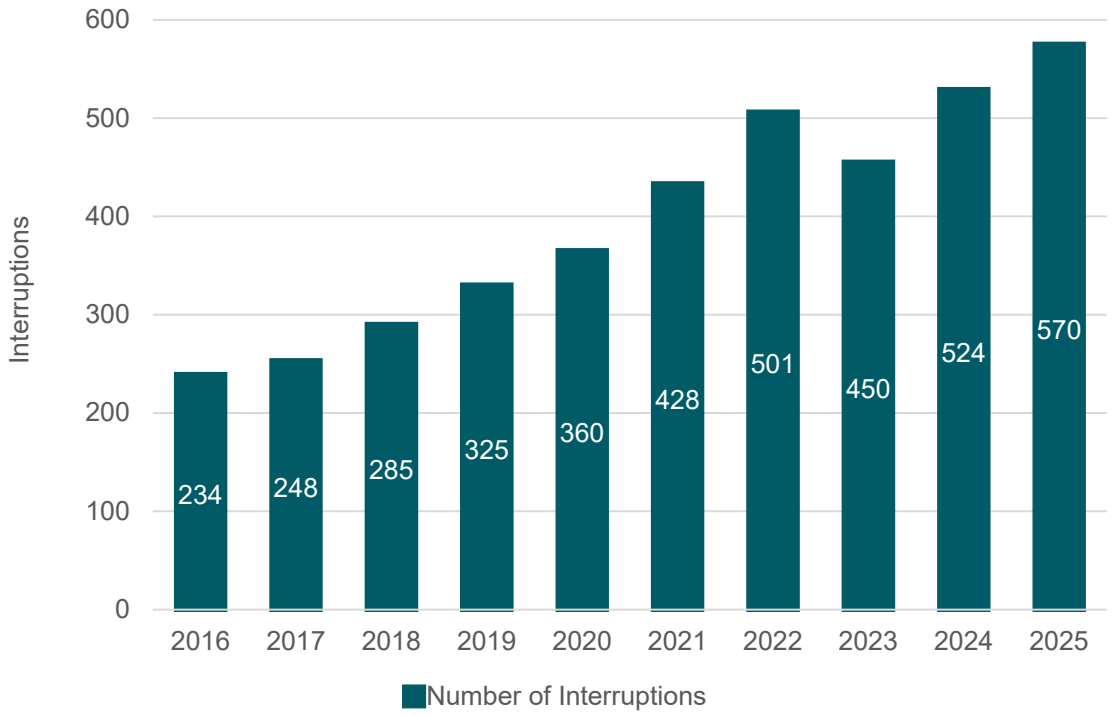


Figure 48: Pole Caused Interruptions Excluding FM

The reliability impact associated with pole failures has also increased. Figure 49 shows the annual SAIDI contribution from outages where at least one pole was replaced, excluding Force Majeure events. Average annual pole-caused SAIDI increased from 0.21 hours during 2016-2020 to 0.35 hours during 2021-2025, an increase of 63%.

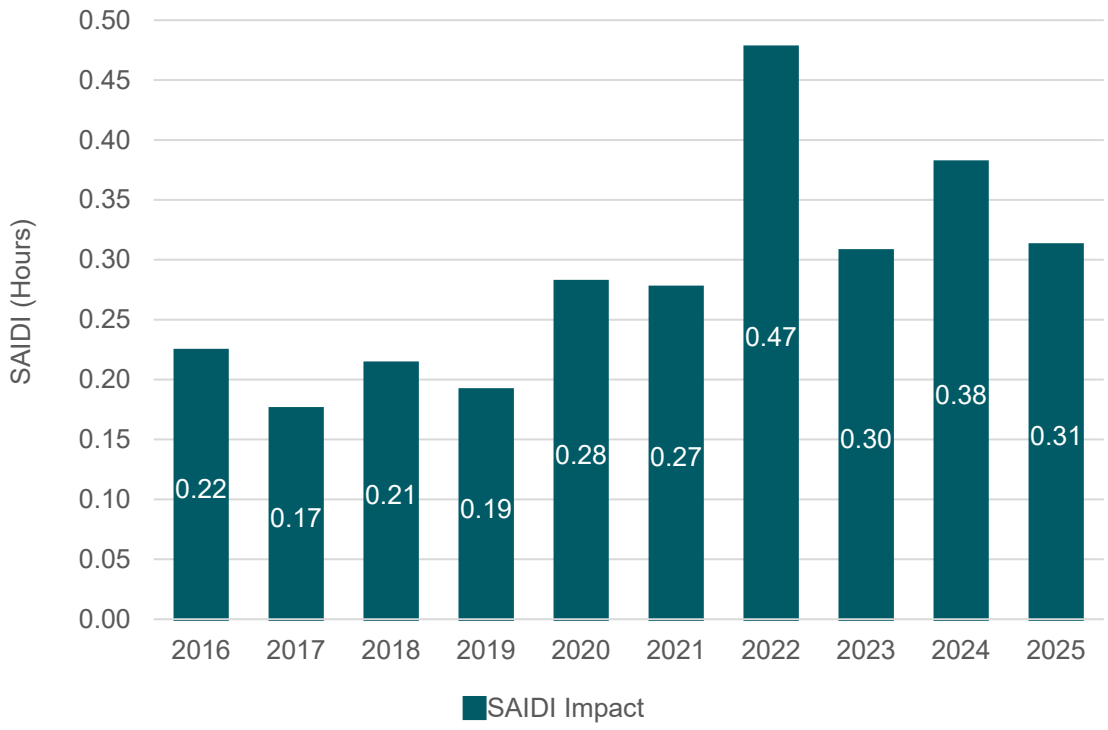


Figure 49: Pole Caused SAIDI (excluding FM)

Figure 50 shows the corresponding SAIFI contribution from pole-related outages. Average annual pole-related SAIFI increased from 0.042 interruptions during 2016-2020 to 0.059 interruptions during 2021-2025, an increase of approximately 40%.

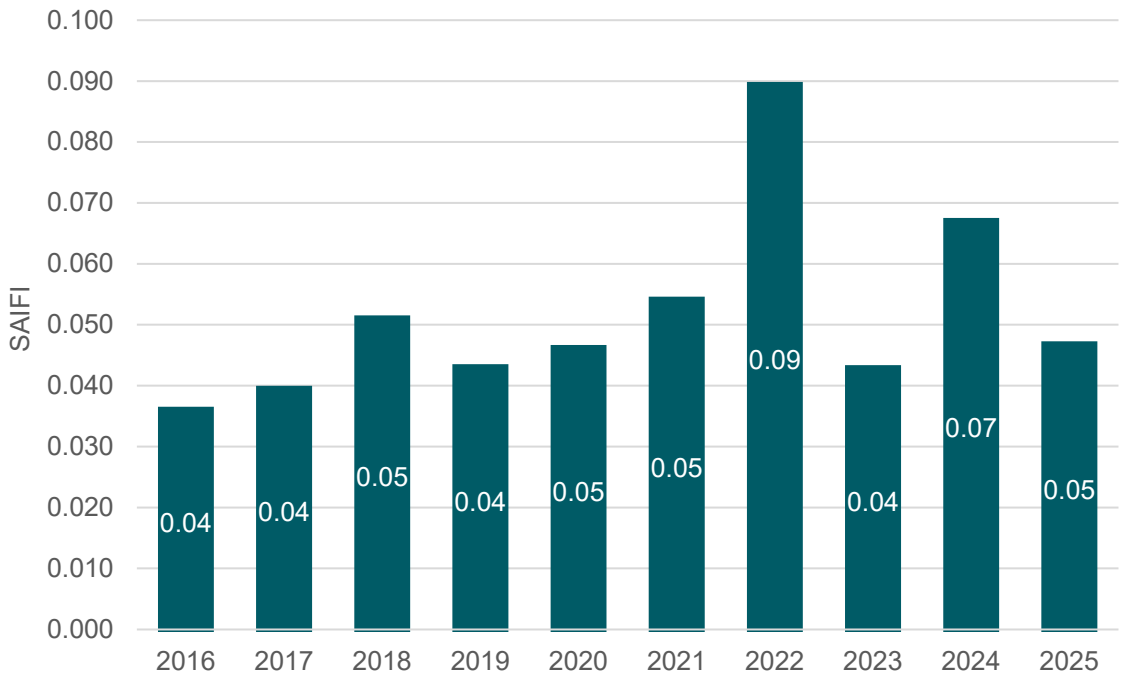


Figure 50: Pole Caused SAIFI Excluding FM

The deterioration of pole-related reliability performance is consistent with the increasing maturity and deteriorating condition of the pole population. Pole reliability can also be influenced by weather, external damage, and location. The longer-term trends show increasing interruption frequency and customer impact alongside growth in the mature and poor condition pole populations. As the pole population continues to age, further deterioration would increase the population of poles exposed to elevated failure risk and place additional pressure on reliability if these condition-driven needs are not addressed through planned lifecycle intervention.

3.2.3.1.3 LIFECYCLE STRATEGY

Hydro One manages its distribution pole population through a lifecycle strategy that combines condition assessment, chemical treatment, mechanical refurbishment and planned replacement. The strategy is intended to address pole deterioration using the most appropriate lifecycle intervention, extending the service life of existing poles where

technically and economically feasible and replacing poles where condition and risk warrant capital renewal.

Pole condition is the principal driver of lifecycle intervention. Hydro One uses visual inspections and quantitative testing to identify deterioration and assess remaining structural strength. The nature and extent of the identified deficiency determines whether a pole can remain in service, can be refurbished, or require replacement. Where replacement is required, the geographic concentration of poor condition poles and the characteristics of the affected feeder section also inform how the work is planned and delivered.

Hydro One's Pole Sustainment Program (DSP Section 3.11, D-SR-07) applies four complementary lifecycle approaches: Test and Treat, Pole Refurbishment, Pole Replacement and Clustered Pole Hardening. These approaches allow Hydro One to address the growing poor condition pole population using an intervention appropriate to the condition, location and risk of the affected assets.

3.2.3.1.3.1 INSPECTION & MAINTENANCE PRACTICES

Poles must be inspected every six years for rural areas and three years for urban areas, consistent with the Minimum Inspection Requirements in Appendix C of the Distribution System Code. 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.

Hydro One collects additional condition data as part of its pole Test and Treat component of DSP Section 3.11, D-SR-07. This program will test and treat approximately 92,000 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 results support decisions regarding continued operation, mechanical refurbishment or replacement.

3.2.3.1.3.2 REPLACEMENT & REFURBISHMENT

Refurbishment

Hydro One has two types of 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 diffuse over time into the wood to rejuvenate the initial treatment at the ground line. Sufficient levels of chemical preservative at the ground line prevent rot and fungal growth and helps to maintain the condition of the pole.

If a pole has 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 shown in Figure 51). 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. 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 51: Mechanically Refurbished Pole

Replacement

Where a poor condition pole cannot be technically or economically refurbished, planned replacement is required to restore structural integrity and manage the associated safety and reliability risk. Poles that do not undergo planned replacement and fail structurally during the plan period would be replaced as part of the Distribution Lines Trouble Call and Storm Damage Response Program (DSP Section 3.11, D-SR-05)

Poor condition poles that are geographically dispersed are generally addressed through individual planned replacement. Where poor condition poles are concentrated along a feeder section, Hydro One can address the condition-driven need through coordinated clustered replacement rather than replacing individual poles separately over time. This allows multiple deteriorated assets within the same line section to be addressed through a coordinated design and construction approach.

For the 2028-2032 period, Hydro One is enhancing its pole lifecycle strategy through greater use of clustered replacement and hardening where poor condition poles are geographically concentrated. Where these clusters are also located on feeder sections that are vulnerable to severe-weather loading, the replacement poles may be installed to a higher structural standard. In these circumstances, poor asset condition establishes the

underlying renewal requirement, while clustered execution and higher-strength replacement provide additional execution-efficiency and resiliency benefits.

Not all poor condition poles are addressed through DSP Section 3.11, D-SR-07. Where the identified need forms part of a broader feeder-section requirement involving deteriorated conductor or other line components, accessibility constraints, non-standard configurations or relocation requirements, the appropriate lifecycle solution may instead be a broader line rebuild or relocation. Poles may also be renewed through voltage conversion, system growth, joint-use and other distribution investments where pole replacement forms part of the broader scope of work.

Overall, Hydro One's pole lifecycle strategy uses condition information to select the appropriate intervention while considering how identified renewal needs can be delivered efficiently. Chemical treatment and mechanical refurbishment extend the life of suitable poles. Individual replacement addresses dispersed poor condition poles that cannot be refurbished. Clustered replacement addresses concentrations of poor condition poles in a coordinated manner. The enhanced approach proposed for 2028-2032 responds to the increasing poor condition pole population by expanding the use of planned, coordinated renewal and, where warranted, incorporating higher-strength replacement to improve resiliency while addressing the underlying condition need.

3.2.3.2 CROSS ARMS

3.2.3.2.1 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.

3.2.3.2.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.3.2.2.1 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.

3.2.3.2.2.2 ASSET CONDITION

Cross arms are visually inspected on a regular basis, and broken, cracked, or otherwise damaged cross arms are identified (see example shown in Figure 53). Approximately 13,800 cross arms are identified as being in poor condition (Figure 52).

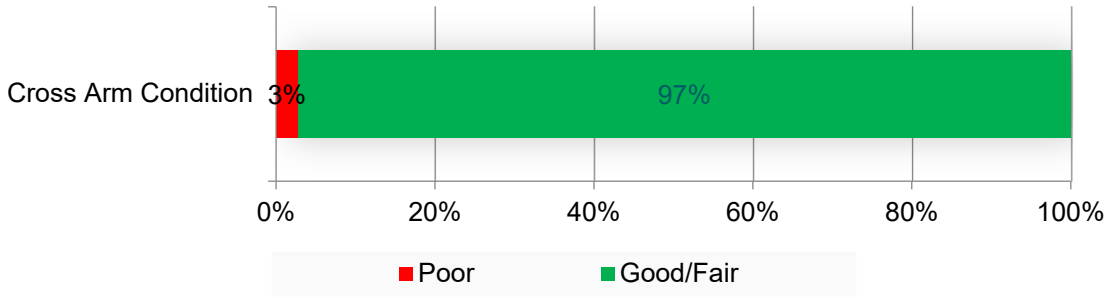


Figure 52: Cross Arm Condition



Figure 53: Cross Arm in Poor Condition

3.2.3.2.2.3 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 2016 to 2025, the average number of outages attributed to cross arm failures has been 103 per year, with an average SAIDI and SAIFI contribution of 6 minutes and 0.03

interruptions, respectively. Figure 54, Figure 55, and Figure 56 provide the number of interruptions, SAIDI and SAIFI contributions attributed to cross arm failures, excluding interruptions during force majeure events. Similar to poles, there has been an increasing trend in these performance metrics.

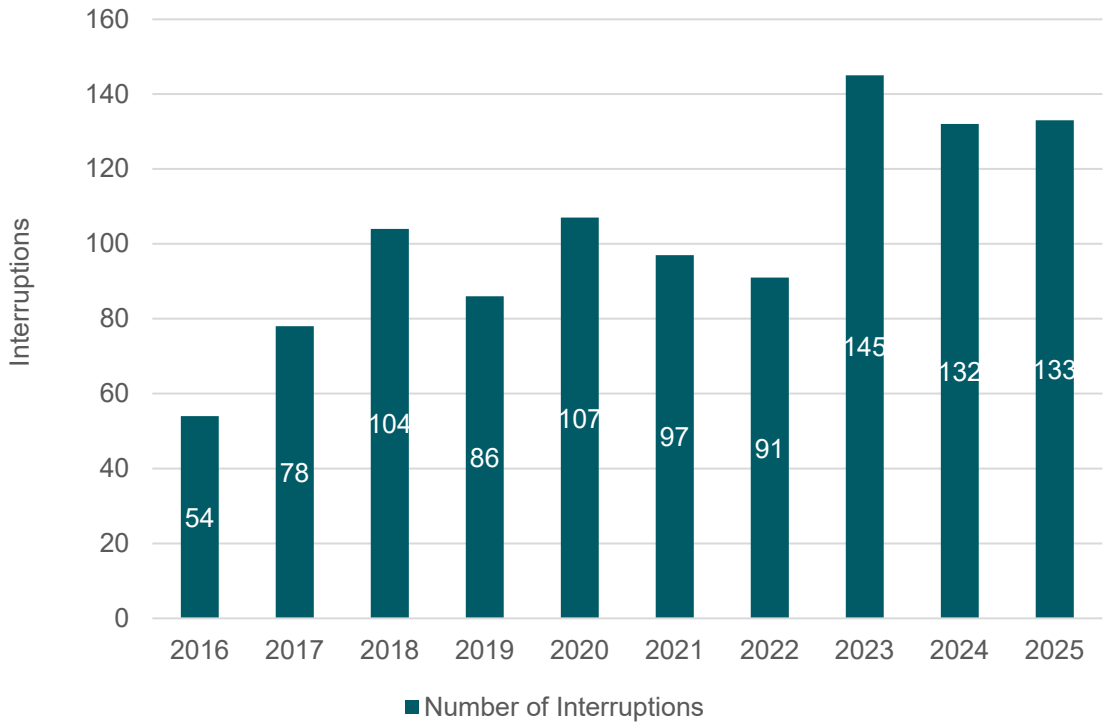


Figure 54: Number of Interruptions Attributed to Cross Arm Failures (Excluding FM)

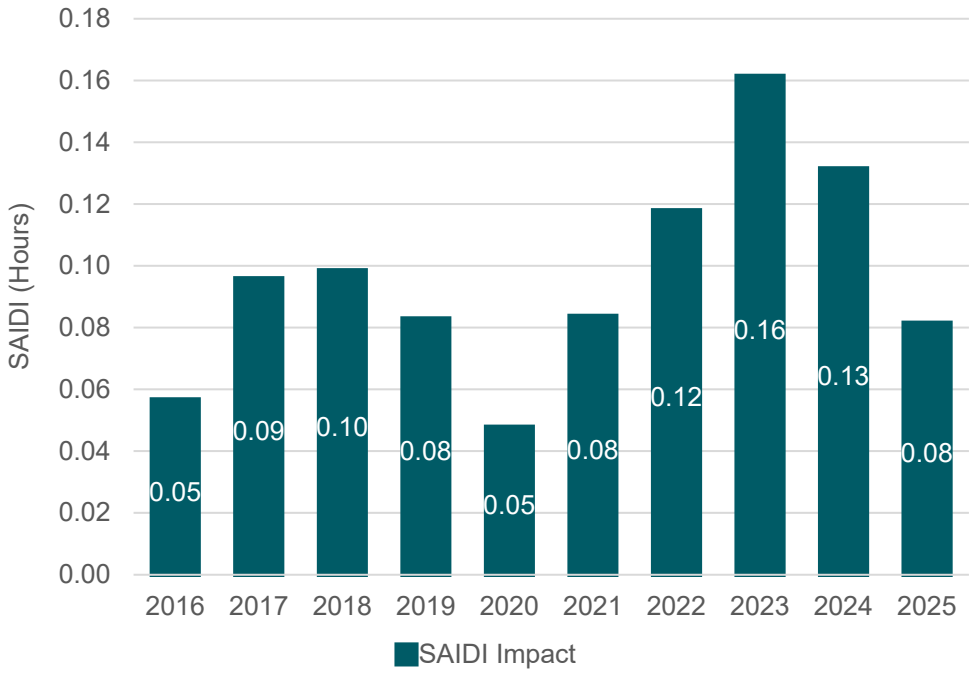


Figure 55: SAIDI Contribution of Interruptions Attributed to Cross Arm Failures (Excluding FM)

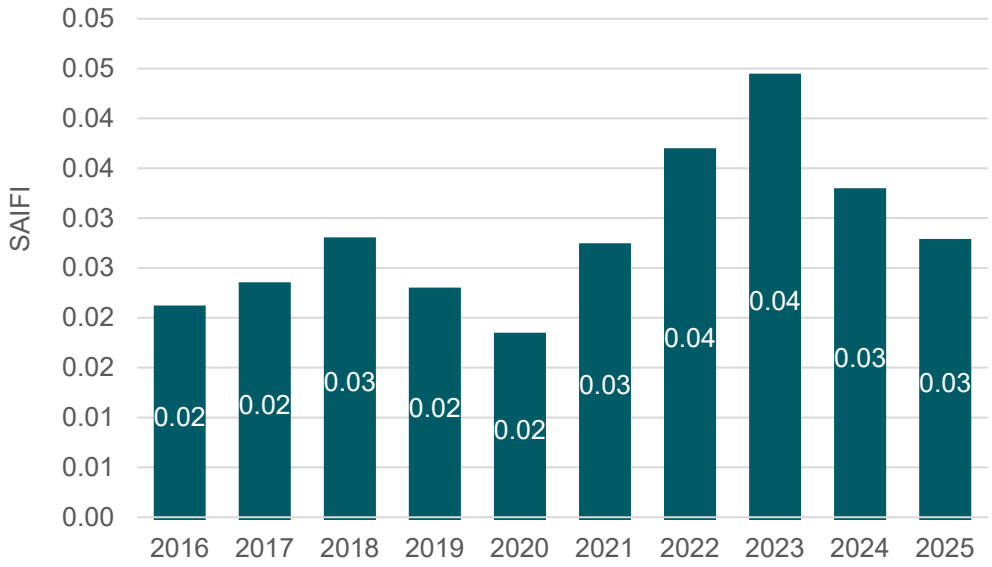


Figure 56: SAIFI Contribution of Interruptions Attributed to Cross Arm Failures (Excluding FM)

3.2.3.2.3 LIFECYCLE STRATEGY

3.2.3.2.3.1 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 patrol program, as discussed in Exhibit E-03-02. Broken, cracked or otherwise damaged cross arms are identified as part of these inspections.

3.2.3.2.3.2 REPLACEMENT & REFURBISHMENT

Cross arms are not refurbished. Hydro One's dedicated program for replacing cross arms in poor condition is the cross-arm replacement program, included in Distribution Lines Minor Component Replacement (DSP Section 3.11, D-SR-08). Cross arms in poor condition are identified as candidates for this program and are selected for inclusion based on the projected impact of failure. Cross arms that do not undergo planned replacement and fail 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 OVERHEAD CONDUCTORS, UNDERGROUND CABLE & SUBMARINE CABLE

3.2.3.3.1 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 126,000 circuit kilometers of primary conductor on its distribution system.

Conductor can be further classified by the nature of its installation. Conductor supported by poles generally consists of a series of bare metal wires and is referred to as *overhead conductor*. Conductor installed 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 2015, new underground cable installations have moved to an all-in-duct design. This design provides greater physical protection, simplifies ongoing maintenance and streamlines future replacement. Conductor 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*.

3.2.3.3.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.3.3.2.1 ASSET DEMOGRAPHICS

As outlined in Table 15 below, Hydro One's distribution system contains a total of 125,988 circuit kilometers of primary line of the following conductor types:

Table 15 - Total Overhead, Underground, and Sub Cable Circuit Kilometers in Hydro One, ORZ and PRZ

Line Type	Hydro One	Orillia RZ	Peterborough RZ
Overhead (km)	113,943	166	337
Sub Cable (km)	4,145	-	-
Underground (km)	7,150	71	176
Total	**125,238**	**237**	**513**

3.2.3.3.2.1.1 OVERHEAD CONDUCTOR

Hydro One does not maintain installation-age information for the overhead conductor population. Overhead conductor is therefore managed primarily based on identified condition deficiencies, performance and broader feeder renewal requirements rather than age.

3.2.3.3.2.1.2 UNDERGROUND CABLE

Hydro One does not maintain complete installation-age information for its underground cable population because these assets have historically been managed predominantly on a run-to-failure basis. To obtain a population-level indication of cable maturity, Hydro One has used the installation age of associated underground pad-mounted transformers as a proxy for the approximate vintage of connected underground cable. Based on this proxy, approximately 34% of the underground cable population is estimated to be 30 years of age or older.

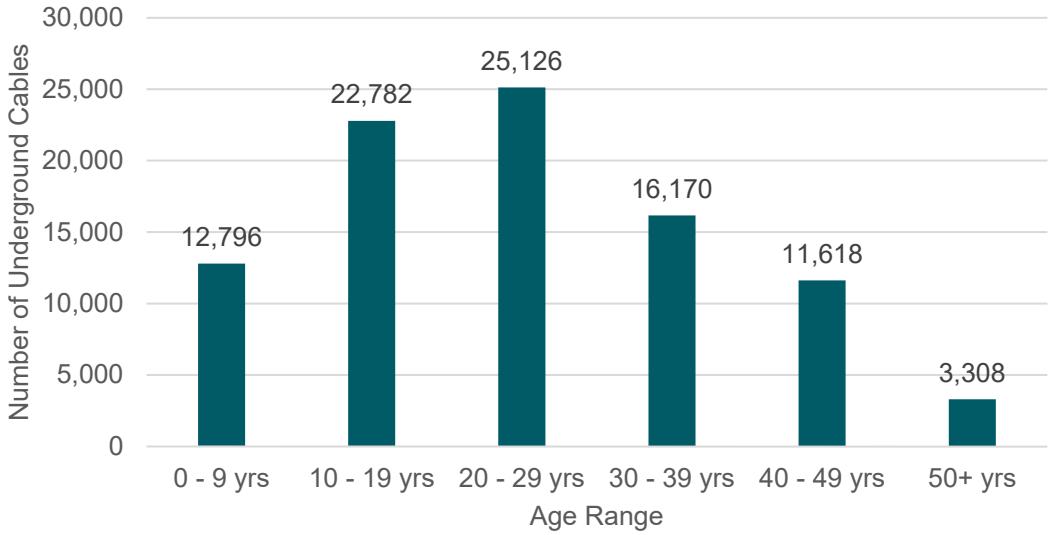


Figure 57: Underground Cables – Age Demographic by Age Group

3.2.3.3.2.1.3 SUBMARINE CABLE

Hydro One does not maintain complete age for the submarine cable population. Therefore, as observed in Figure 58 below, the age for majority of the submarine cable population is unknown. Submarine cable lifecycle requirements are assessed primarily based on observed condition, including cable damage, exposure and deterioration identified through periodic inspections, rather than age.

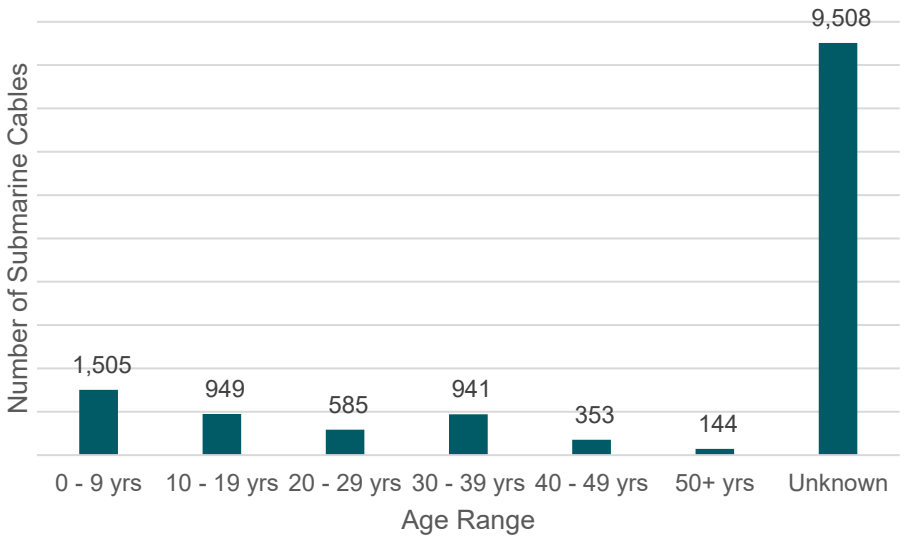


Figure 58: Submarine Cables – Age Demographic by Age Group

3.2.3.3.2.2 ASSET CONDITION

3.2.3.3.2.2.1 OVERHEAD CONDUCTOR

Overhead conductors are visually inspected every six years for rural areas and three years for urban areas. These inspections identify conductor defects such as broken strands, severe corrosion, insufficient clearance and other conductor defects that may affect system reliability or safety. Based on recent assessments, there are approximately 14,000 overhead conductor defects that have been identified on the distribution system.

3.2.3.3.2.2.2 UNDERGROUND CABLE

Underground cables are inspected every six years for rural areas and three years for urban areas through dedicated underground system patrols, during which exposed or damaged cables are identified. There are currently approximately 1,800 underground cable defects identified on the distribution system.

These visually identified defects do not provide a direct assessment of the internal condition of the buried cable insulation. Underground system patrols can generally observe only accessible portions of the cable installation and associated equipment, and some identified defects may relate to exposed or ancillary components rather than

deterioration mechanisms that ultimately result in cable failure. As underground cable ages, moisture ingress and sustained electrical stress can result in insulation degradation, including the development of water trees. As this deterioration progresses, the cable can fault and cause an unplanned customer interruption. Since 2016, the number of interruptions resulting from underground cables has increased by 60%, highlighting the need for detailed diagnostics and a more proactive asset management approach. Historically, Hydro One did not require detailed cable-condition information because underground cable was predominantly managed through reactive repair following failure. However, the increasing number of underground cable interruptions indicates that this historical approach is becoming less appropriate for aging cable populations in certain communities. Beginning in 2028, as discussed further under Lifecycle Strategy and in DSP Section 3.11, D-SR-15, Hydro One proposes to introduce diagnostic testing to directly assess cable condition in areas experiencing poor underground cable reliability.

3.2.3.3.2.2.3 SUBMARINE CABLE

Submarine cables are visually inspected on a regular basis via dedicated submarine cable patrols, during which exposed or damaged cables and deficiencies in mechanical protection are identified. As seen in Figure 59 below, approximately 10% of the submarine cable population is currently identified as being in poor condition. Approximately 600 submarine cables require refurbishment or restoration of mechanical protection, while approximately 750 submarine cables require replacement based on the nature and extent of the identified deficiency.

The nature of the condition deficiency determines the appropriate intervention. An exposed submarine cable may otherwise remain in serviceable condition but require restoration of mechanical or shoreline protection to reduce the potential for public contact. A damaged cable has experienced deterioration of protective or concentric-neutral components and may require repair or replacement depending on the extent of deterioration and associated safety risk.

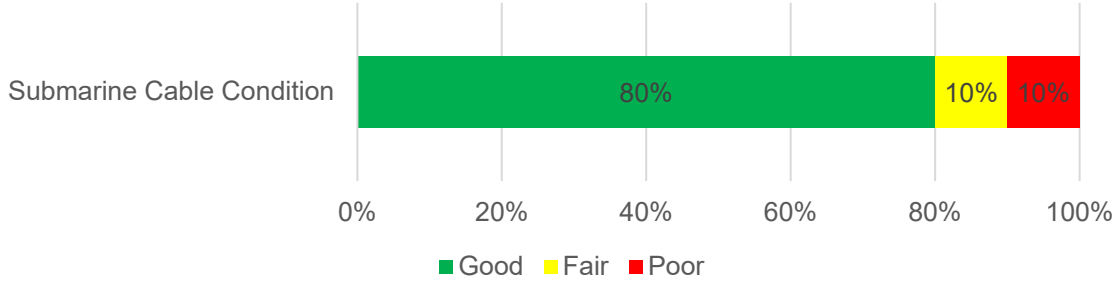


Figure 59: Submarine Cable Condition as of 2025 Year-End

Importantly, repeated inspections demonstrate that submarine cable condition is continuing to deteriorate. Of the submarine cables inspected in both 2018 and 2024, approximately 32% exhibited further deterioration based on corrosion or loss of cable armour. Approximately 15% moved from good condition in 2018 to fair or poor condition in 2024. In addition, of the cables showing no evidence of corrosion in 2018, approximately 25% exhibited light corrosion by 2024. These results demonstrate the progressive nature of deterioration within the submarine cable population and support planned intervention before deficiencies develop into more significant safety or reliability issues.

3.2.3.3.2.3 ASSET PERFORMANCE

3.2.3.3.2.3.1 OVERHEAD CONDUCTOR

Overhead conductor failures are typically due to external forces (e.g., trees falling into conductors). These types of failures are not attributed to the condition of the conductor itself. However, overhead conductor can also fail, for example at a splice or as a result of conductor deterioration.

Figures 60, 61, and 62 provide the number of interruptions, SAIDI and SAIFI contributions attributed to overhead conductor failures, excluding interruptions during force majeure events. From 2016 to 2025, there have been an average of 804 interruptions directly attributed to overhead conductor failures per year, with an average annual SAIDI and SAIFI contribution of 0.29 hours and 0.07 interruptions, respectively. The figures show a deteriorating trend in the number of conductor-related interruptions and their associated SAIDI and SAIFI impacts over the historical period.

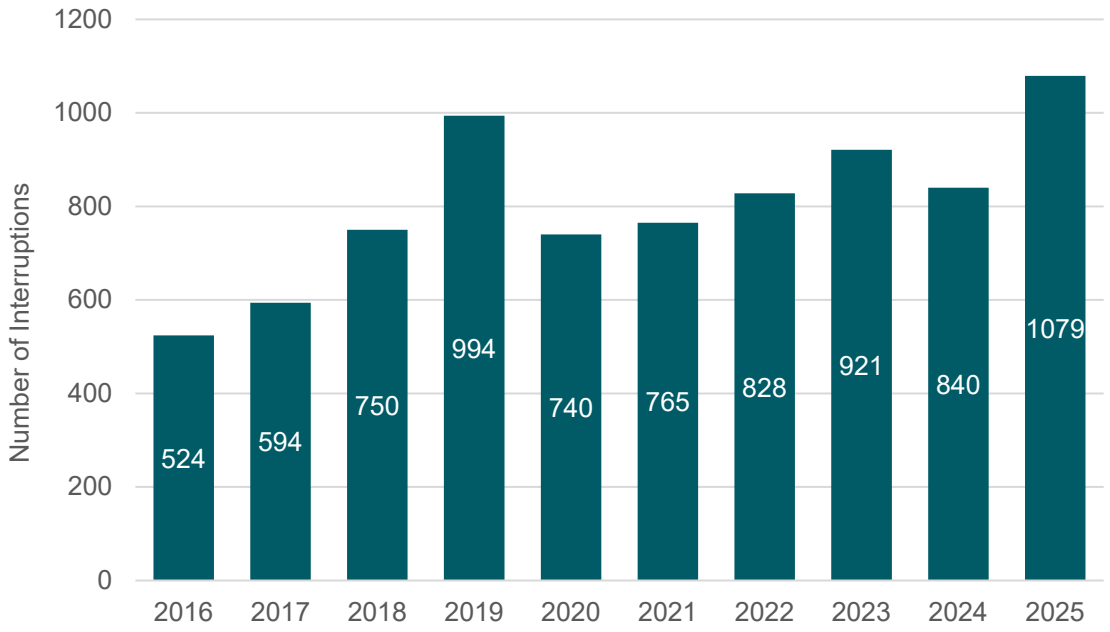


Figure 60: Number of Interruptions Attributed to Overhead Conductor Failure (Excluding FM)

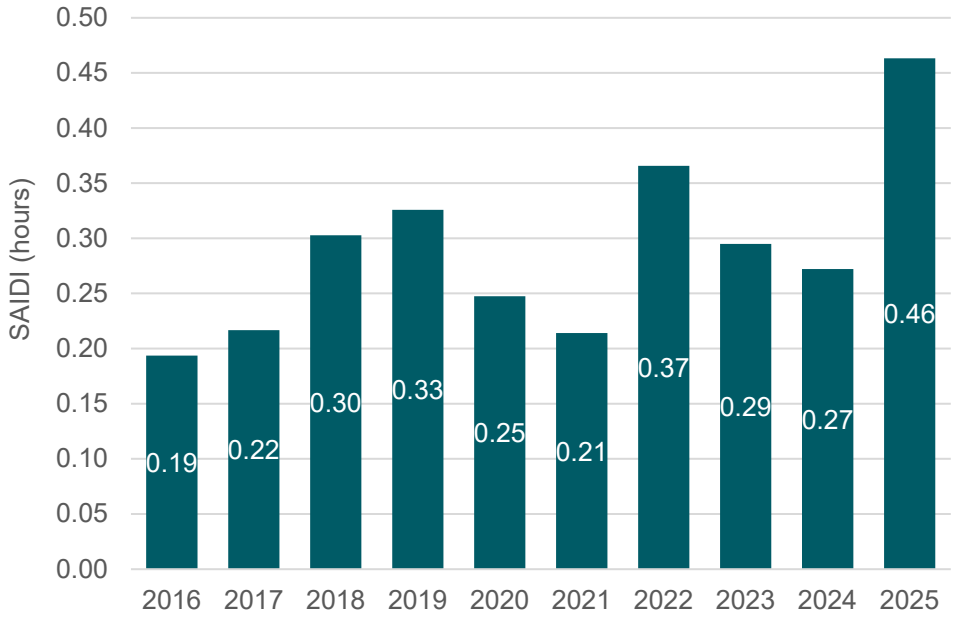


Figure 61: SAIDI Contribution of Interruptions Attributed to Overhead Conductor Failure (Excluding FM)

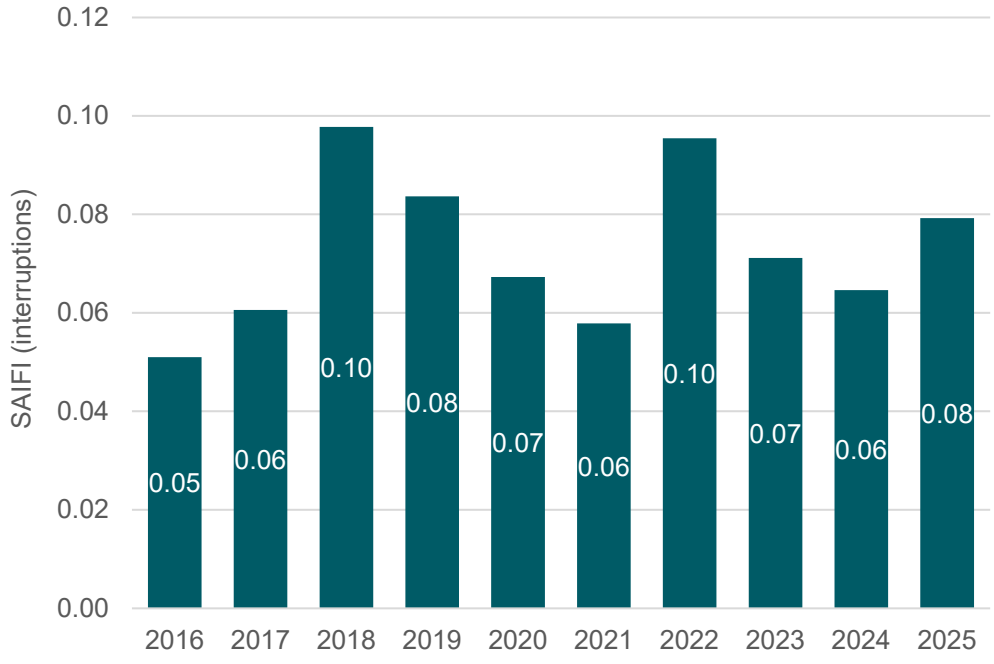


Figure 62: SAIFI Contribution of Interruptions Attributed to Overhead Conductor Failure (Excluding FM)

The deterioration in overhead conductor reliability performance is occurring in the context of increasing weather and vegetation-related pressures on Hydro One's predominantly overhead distribution system. Increased storm frequency and severity expose overhead lines to greater wind, ice, precipitation and other mechanical stresses, as discussed further in DSP Section 3.11, D-SR-05, Distribution Lines Trouble Call and Storm Damage Response.

Vegetation-related pressures have also increased. As discussed in Section 3.2.3.5, Rights-of-Way, vegetation defect density and vegetation-related reliability impacts have increased in recent years, with tree-caused SAIDI, SAIFI and outages all deteriorating between 2023 and 2025. Trees and vegetation can directly contact overhead lines or fail onto conductors during adverse weather, increasing the physical stresses experienced by the overhead system. These weather and vegetation trends likely contribute, together with conductor-specific deterioration and defects, to the worsening reliability performance observed for overhead conductors.

3.2.3.3.2.3.2 UNDERGROUND CABLE

Due to the nature of their installation, underground cables are generally protected from external influences including weather related damage, vegetation contact, and other forms of foreign interference. As a result, underground cables can provide reliable service for much of their operating lives. As older cables age, however, electrical and environmental stresses can progressively degrade cable insulation and increase the likelihood of faults and other power quality issues.

Since 2016, the number of interruptions attributable to underground cable failures has increased by approximately 75%, as shown in Figure 63 below. This deterioration in performance is consistent with the aging direct-buried cable population and known deterioration mechanisms affecting older cable insulation, including moisture ingress, electrical stress and water-tree development. Prior to 2015, most underground cable installations were direct-buried.

Unlike cables installed within conduit systems, direct-buried cables have limited physical and mechanical protection, making them more susceptible to environmental stresses and external deterioration mechanisms that can adversely affect performance and reliability. As these assets age, moisture ingress and sustained electrical stress can contribute to insulation degradation, particularly in older cable designs that do not incorporate strand-blocking technology, resulting in unpredictable faults.

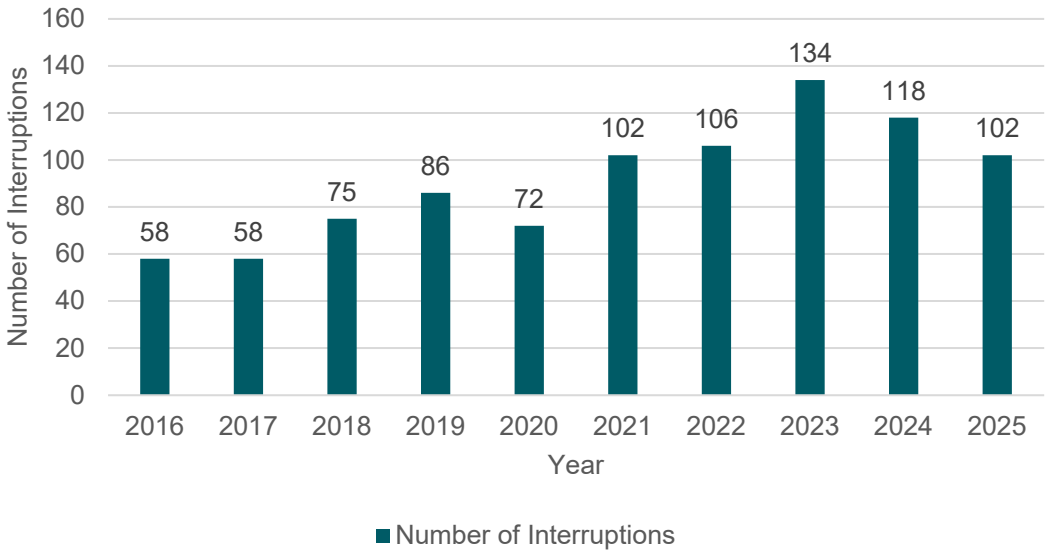


Figure 63: Number of Underground Cable Interruptions due to Equipment Failure (FM Excluded)

The increase in underground cable interruptions is particularly important because internal insulation deterioration cannot generally be identified through the existing visual inspection process. The worsening reliability performance therefore provides an important indicator that the lifecycle risks associated with portions of the mature underground cable population are increasing and that additional condition information is required.

Reactive repairs, which typically involve installing a splice to address an isolated cable defect, do not resolve the underlying deterioration affecting the remaining cable segment. Consequently, the same deteriorated cable can experience subsequent failures at

different locations, resulting in repeated customer interruptions, excavations within residential communities, and reactive field work.

Newmarket, Lincoln, Orleans, Bolton, and Essex are currently experiencing some of the highest levels of customer hours lost attributable to unplanned underground cable interruptions within Hydro One's distribution service territory, as shown in Figure 64 below. These communities contain significant populations of aging underground cable assets, many of which are direct-buried installations or installed using non-Hydro One standards (specifically for areas that were acquired from other LDCs such as Bolton and Stouffville). In addition, portions of these systems lack back-feed capability, limiting Hydro One's ability to restore service quickly during interruptions.

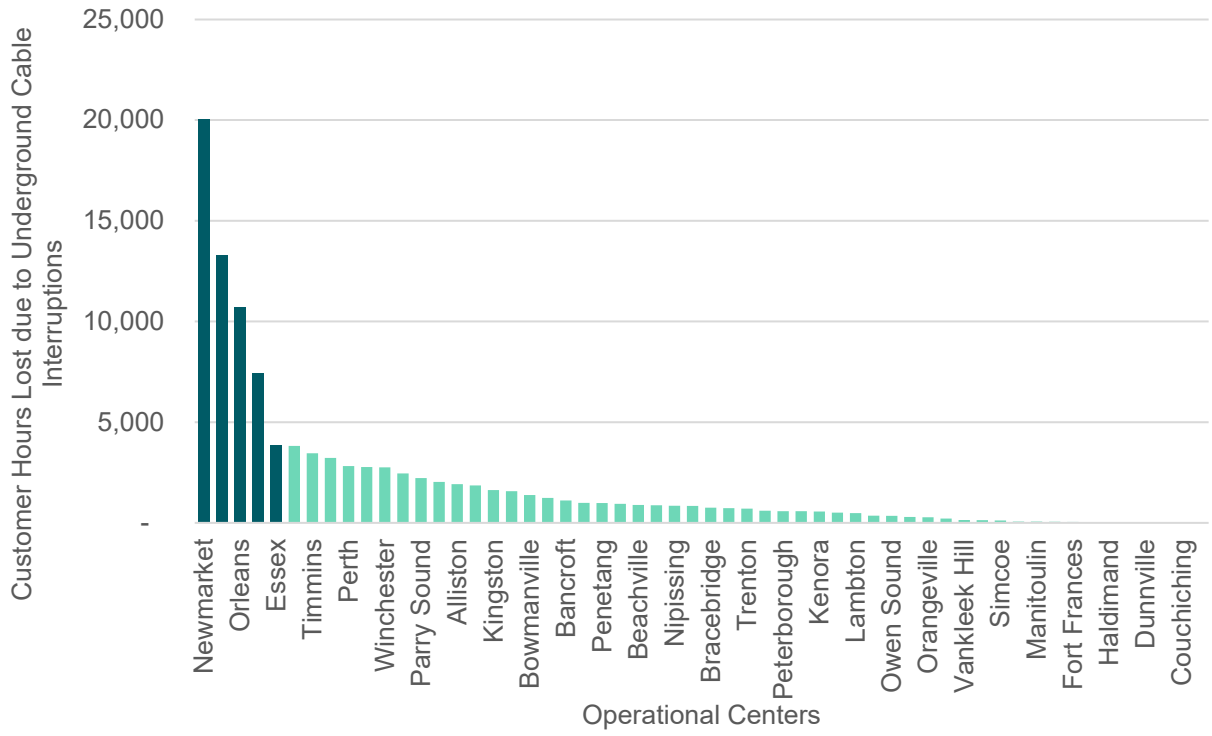


Figure 64: Operational Centers with most Customers Hours Impacted due to Underground Cable Interruptions caused by Equipment Failure, FM Excluded, 2020 to 2025

3.2.3.3.2.3.3 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, submarine cable failures usually impact a low number of customers.

Figures 65, 66, and 67 provide the number of interruptions, SAIDI and SAIFI contributions attributed to submarine cable failures, excluding interruptions during force majeure events. From 2016 to 2025, there have been an average of 87 interruptions attributed to submarine cable failures per year, with an average annual SAIDI and SAIFI contribution of 0.031 hours and 0.0023 interruptions, respectively.

While the impact to overall system reliability of submarine cables is relatively small, an individual failure can have significant consequences for the affected customers. Submarine cable access and repair can be difficult, particularly during winter conditions, and a failure can therefore result in an extended local outage.

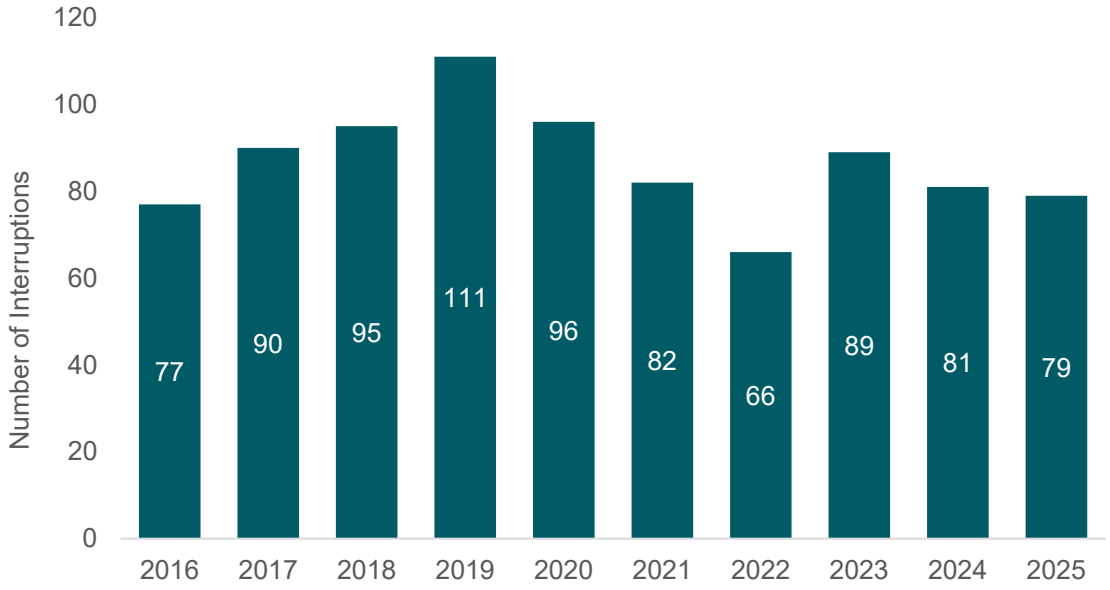


Figure 65: Number of Interruptions Attributed to Submarine Cable Failure (Excluding FM)

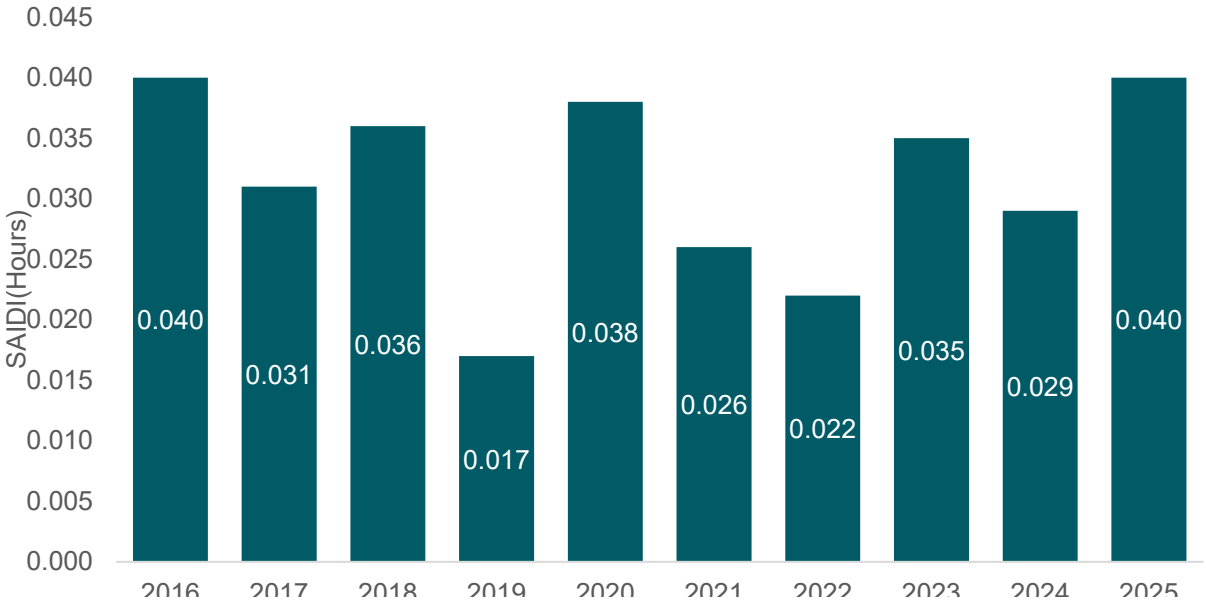


Figure 66: SAIDI Contribution of Interruptions Attributed to Submarine Cable Failure (Excluding FM)

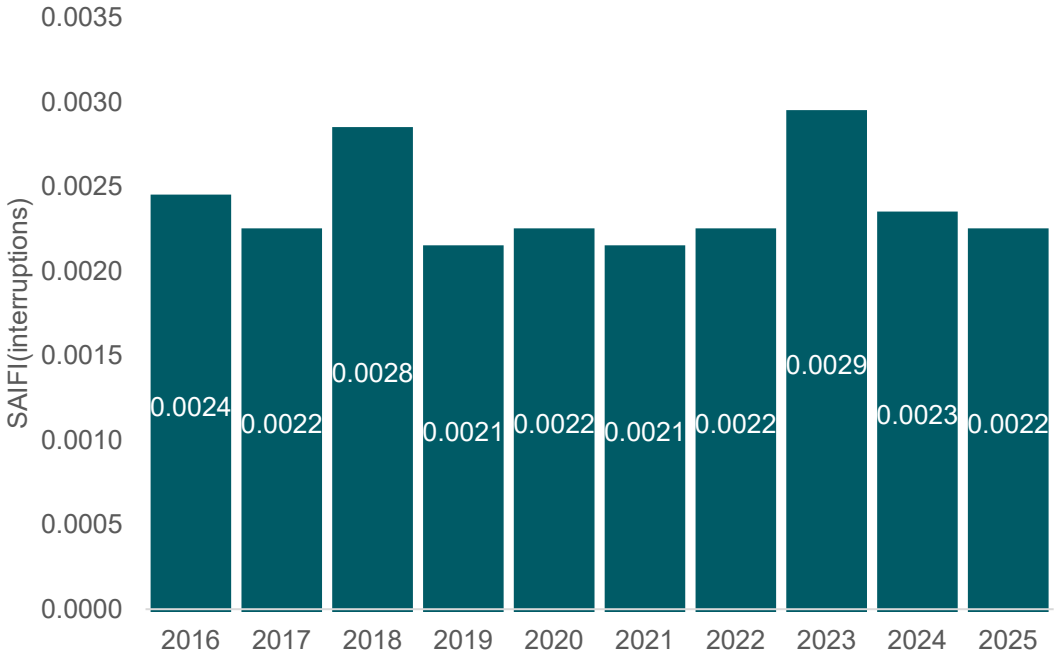


Figure 67: SAIFI Contribution of Interruptions Attributed to Submarine Cable Failure (Excluding FM)

System-wide reliability performance is not, however, the principal indicator of submarine cable renewal need. Because many submarine cable installations serve relatively few customers, progressive physical deterioration may have limited effect on system-wide SAIDI and SAIFI while still presenting material location-specific public safety risk. Planned submarine cable renewal is therefore principally driven by identified physical condition and safety deficiencies, with reliability and restoration consequences considered as additional factors.

3.2.3.3.3 LIFECYCLE STRATEGY

Hydro One applies different lifecycle approaches to overhead conductor, underground cable and submarine cable based on the nature of each asset, the available condition information and the consequences of failure. Overhead conductor is primarily managed through inspection, repair and broader feeder renewal. Underground cable is transitioning from predominantly reactive repair toward diagnostics-informed planned renewal.

Submarine cable is managed through inspection and condition- or safety-driven refurbishment, repair and replacement.

3.2.3.3.3.1 INSPECTION & MAINTENANCE PRACTICES

3.2.3.3.3.1.1 OVERHEAD CONDUCTOR

Overhead conductor is subject to the same six-year (rural)/three-year (urban) inspection requirements as other distribution lines assets. Inspections consist primarily of visual assessments that identify broken strands, severe corrosion, and other conductor defects.

Advanced testing techniques are available for assessing overhead conductor condition, but detailed testing is complex and generally not cost-effective for distribution lines. Accordingly, detailed conductor testing is undertaken only when a specific need warrants it.

3.2.3.3.3.1.2 UNDERGROUND CABLE

Underground cables are subject to the same inspection requirements as other distribution line assets, requiring inspection every six years in rural areas and every three years in urban areas. Dedicated underground system patrols inspect accessible cable portions, enclosed equipment, cable terminations and other visible components and identify exposed cable and other deficiencies.

These visual inspections are important for identifying accessible deficiencies but cannot determine the condition of insulation along the buried cable segment. As underground cable reliability has deteriorated, Hydro One's lifecycle strategy is therefore evolving to incorporate diagnostic testing capable of obtaining direct information on cable insulation condition.

Underground cable interruptions can cause extensive outage durations due to the complexity of work and lack of back-feed capability in some areas. As underground cables age, the risk of unplanned interruption increases. As the number of interruptions continues to increase, a dedicated program, *Underground Cable Diagnostic Program,* will be used to gather condition and age demographic data.

Beginning in 2028, Hydro One proposes to implement an underground cable diagnostic program in areas experiencing poor underground cable reliability, as discussed in DSP Section 3.11, D-SR-15. Based on year-end 2025 reliability information, Essex, Newmarket (Stouffville area), Orleans, Lincoln, and Bolton have been identified as initial focus areas.

The diagnostic program will include industry standard techniques such as the Very Low Frequency (VLF) Tan-Delta test and Time Domain Reflectometry (TDR) test to assess the insulation condition of the cable and to determine the number of splices and their locations.

This represents an important evolution of Hydro One's underground cable lifecycle strategy for 2028-2032. Historically, limited condition information was required under a predominantly run-to-failure approach. The proposed diagnostic program will allow Hydro One to progressively transition toward a condition-informed strategy in which reliability identifies areas of concern, diagnostic testing assesses individual cable segments, and the resulting condition information determines whether continued operation, rejuvenation or replacement provides the appropriate lifecycle response.

3.2.3.3.3.1.3 SUBMARINE CABLE

Submarine cable inspections are subject to the same six-year (rural)/three-year (urban) inspection requirements as other distribution lines assets. The cables are inspected through dedicated submarine system inspections. Inspections include visual assessment of cable condition and mechanical protection with particular attention to locations where public contact is possible, including recreational and shoreline areas.

The inspection identifies damage to the cable's concentric neutral, deterioration of protective components, exposure and other deficiencies. Where a detailed visual inspection cannot be completed in an area with potential public contact, a TDR test can be performed to verify the condition of the cable.

3.2.3.3.3.2 REPLACEMENT & REFURBISHMENT

3.2.3.3.3.2.1 OVERHEAD CONDUCTOR

Overhead conductor is repaired when damaged by deterioration 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 generally be completed by splicing new sections of conductor in place of the damaged sections.

Due to the relatively long service life of overhead conductor and the ability to repair localized damage, replacement of large conductor sections is not generally driven by conductor condition alone. Overhead conductor is typically replaced as part of broader feeder renewal, relocation, voltage conversion or capacity-related projects where renewal of the line section provides the appropriate lifecycle solution.

3.2.3.3.3.2.2 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 cable section 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.

Historically, underground cables in the Hydro One network have been run to failure. This approach was appropriate while failures were relatively infrequent and the cost and customer impact of reactive repair remained manageable.

The approximately 75% increase in underground cable interruptions since 2016 indicates increasing performance pressure within aging direct-buried cable populations. Hydro One is therefore transitioning during 2028-2032 from predominantly reactive repair toward diagnostics-informed planned renewal in areas with concentrated underground cable reliability issues, as described in DSP Section 3.11, D-SR-15.

Following diagnostic testing, Hydro One will determine the appropriate intervention for the affected cable segment. Cable rejuvenation through injection will be used where the cable condition and construction make rejuvenation technically suitable and where it provides the more cost-effective lifecycle intervention. Where diagnostic results indicate that rejuvenation will not adequately address the cable condition, or where the cable is otherwise unsuitable for injection, planned replacement will be undertaken.

Hydro One has used cable injection technology primarily in the Orleans area since 2018. This initiative has resulted in significant productivity savings (discussed further in SPF Section 1.04, Attachment 1) and reliability improvements. Hydro One plans to expand its use where technically and economically appropriate during the 2028-2032 period.

Where replacement is required, existing direct-buried cable will generally be replaced with modern XLPE cable installed in PVC conduit. The conduit system provides greater protection from mechanical and environmental stresses and facilitates future cable replacement.

The revised lifecycle strategy is intended to address the underlying deterioration of aging cable segments rather than repeatedly responding to isolated failures. By combining reliability information with diagnostic condition testing, Hydro One can target planned intervention to cable segments with the greatest need and select rejuvenation or replacement based on the condition and characteristics of the individual cable.

3.2.3.3.3.2.3 SUBMARINE CABLE

Hydro One uses refurbishment and replacement to address submarine cable deficiencies depending on the nature and severity of the condition issue.

Where a submarine cable is otherwise serviceable but has become exposed or has inadequate mechanical protection, Hydro One can restore or install mechanical shoreline protection to mitigate the potential for incidental public contact without replacing the cable.

Where inspection identifies damage to the concentric neutral or other cable components, Hydro One assesses whether the cable can be safely repaired or requires replacement. Conditions requiring immediate response include significant loss of the concentric neutral, non-standard temporary repairs or another condition determined to present an immediate hazard. Where repair cannot adequately address the identified condition or safety risk, the cable is replaced.

Planned replacement is also used to address poor condition cables before deterioration becomes emergent. Depending on the extent and location of the deficiency, Hydro One

may replace the entire cable or only the affected section where localized replacement provides the appropriate lifecycle solution.

The submarine cable lifecycle strategy has not materially changed from 2023-2027 period. The increased renewal requirement for 2028-2032 is principally driven by the larger identified population of damaged and exposed cables and observed continued deterioration between inspection cycles, rather than by a change in Hydro One's fundamental asset-management approach.

3.2.3.4 LINE TRANSFORMERS

3.2.3.4.1 ASSET DESCRIPTION / PURPOSE

Distribution Line Transformers are used to convert electricity from primary distribution voltage levels (e.g., 44kV, 27.6kV, 12.48kV) to secondary voltage levels (e.g., 600 V or 240 V/120 V) so the power can be utilized by small business and residential 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 68: Picture of Pole-Top Line Transformer

3.2.3.4.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.3.4.2.1 ASSET DEMOGRAPHICS

Hydro One maintains a total fleet of approximately 554,000 transformers in overhead (pole mounted) or underground (pad mounted, submersible, transclosure or pole-transformer) configurations. Table 16 provides a breakdown of transformers by type, and Figures 69 through 74 provide the age profile of overhead and underground transformers, respectively.

Table 16 - Line Transformer Type

Transformer Type	Hydro One Rate Zone	Orillia Rate Zone	Peterborough Rate Zone	Total
Overhead: Pole Mounted Transformers	472,000	930	2,410	475,340
Underground: Pad Mounted Transformers	76,000	690	1,500	78,190
Underground: Submersible Transformers	70	0	0	70
Underground: Transclosures and Pole-Transformers	740	0	0	740

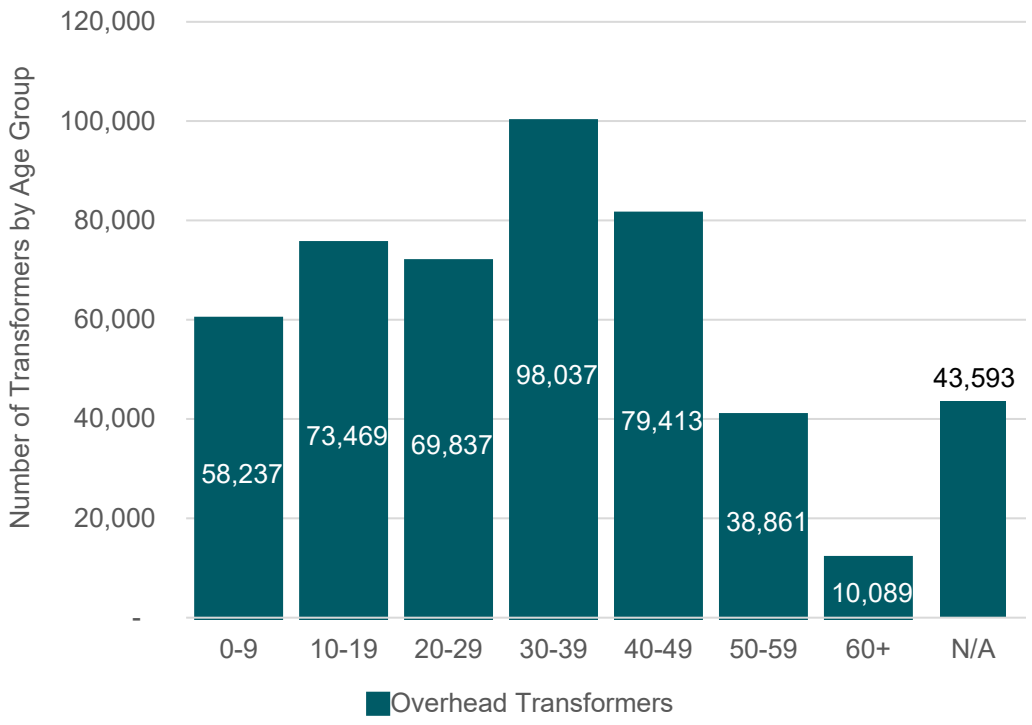


Figure 69: Demographics of Hydro One Owned Overhead Transformers in Hydro One Rate Zone

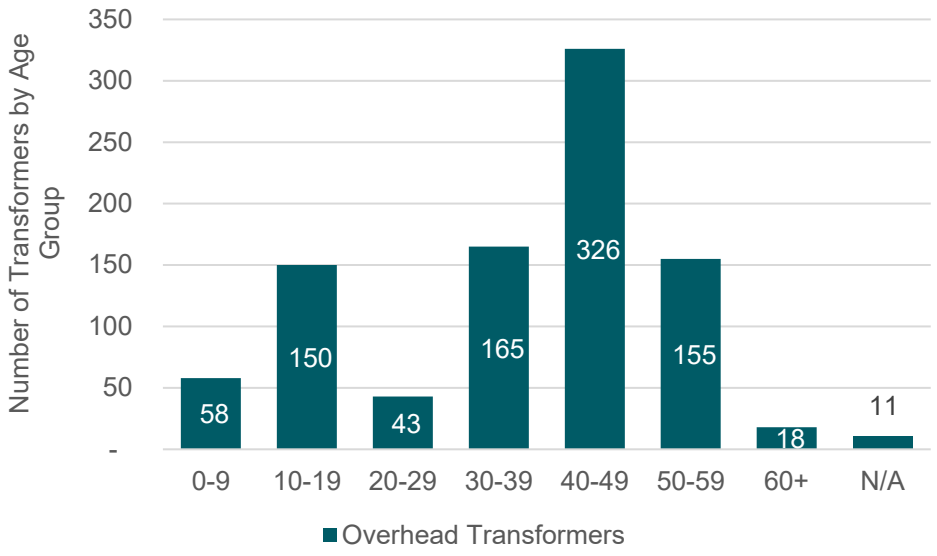


Figure 70: Demographics of Hydro One Owned Overhead Transformers in Orillia Rate Zone

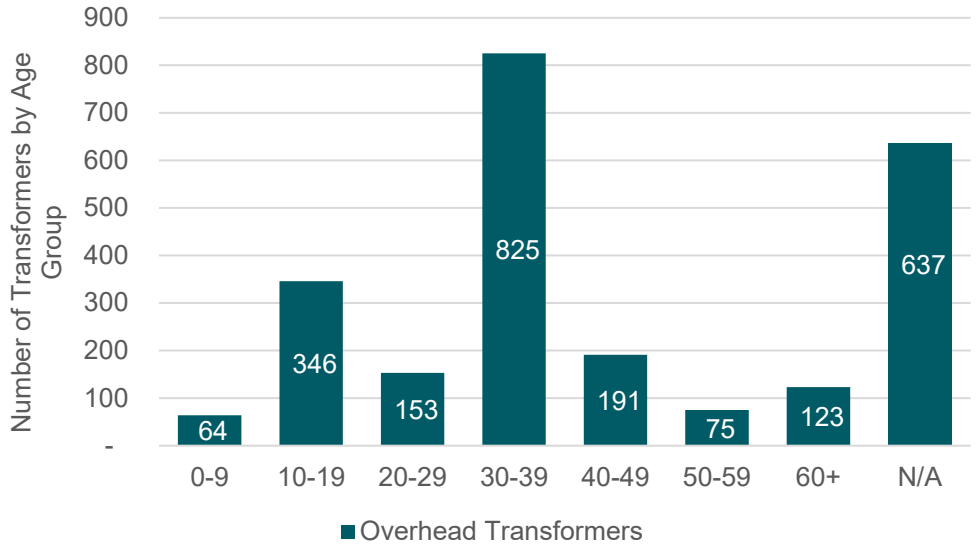


Figure 71: Demographics of Hydro One Owned Overhead Transformers in Peterborough Rate Zone

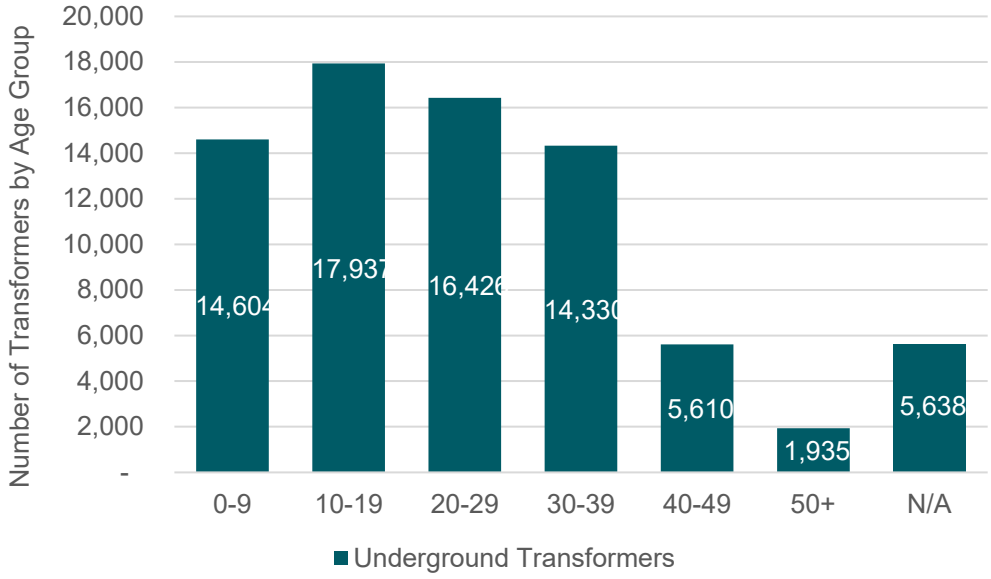


Figure 72: Demographics of Hydro One Owned Underground Transformers in Hydro One Rate Zone

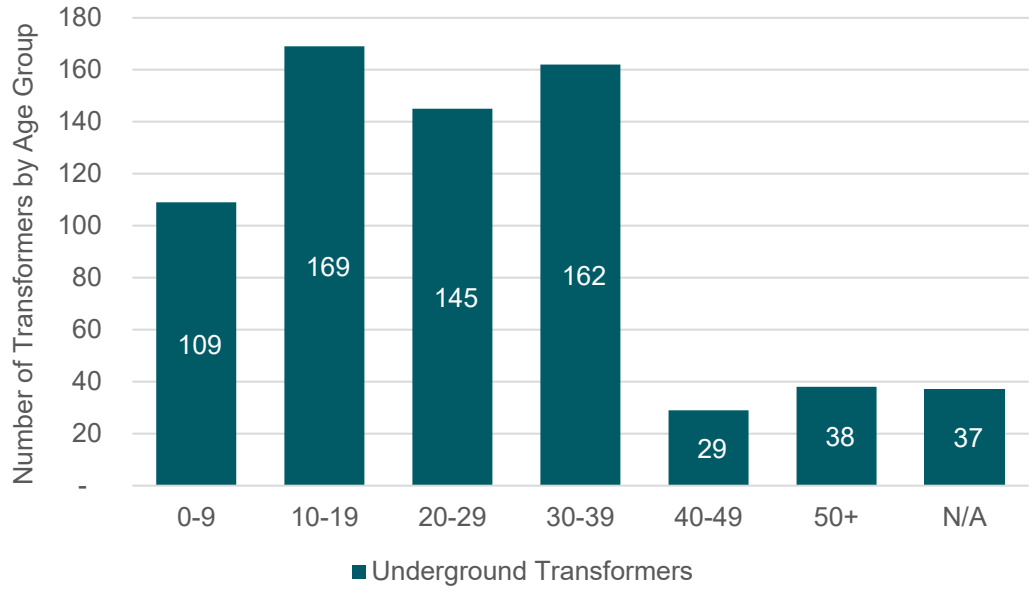


Figure 73: Demographics of Hydro One Owned Underground Transformers in Orillia Rate Zone

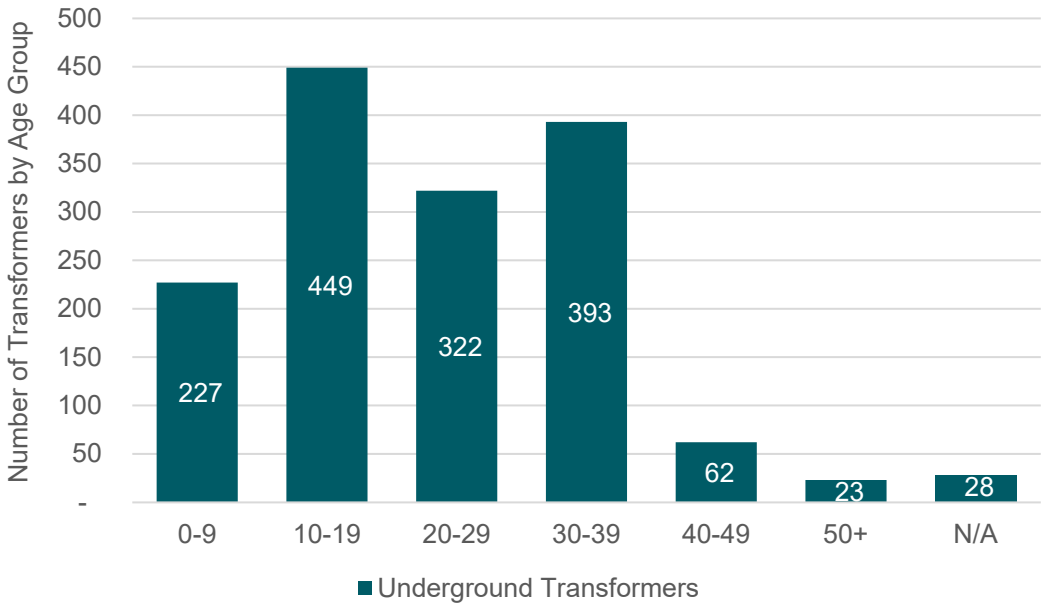


Figure 74: Demographics of Hydro One Owned Underground Transformers in Peterborough Rate Zone

3.2.3.4.2.2 ASSET CONDITION

The primary consideration in assessing the condition of distribution line transformers is the potential internal degradation resulting from 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).

Over time, these factors can contribute to the deterioration of internal insulation and other transformer components, ultimately increasing the risk of failure. As distribution line transformers typically serve a relatively small number of customers and have a relatively low replacement cost, conducting detailed internal condition assessment is generally not cost-effective. As a result, asset condition is not available for these assets.

3.2.3.4.3 ASSET PERFORMANCE

3.2.3.4.3.1 *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. Figures 75, 76, and 77 provide the number of interruptions, SAIDI and SAIFI contributions attributed to overhead transformer failures, excluding interruptions during force majeure events. From 2016 to 2025, there have been an average of 1,068 interruptions attributed to overhead transformer failures per year, with an average annual SAIDI and SAIFI contribution of 0.0117 hours and 0.0022 interruptions, respectively.

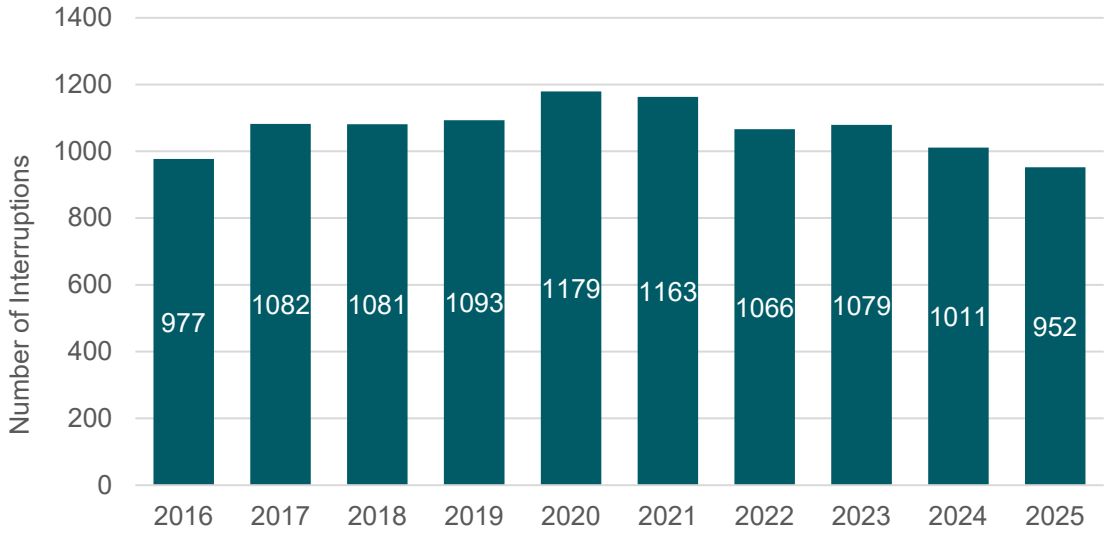


Figure 75: Number of Interruptions Attributed to Overhead Transformer Failures (Excluding FM)

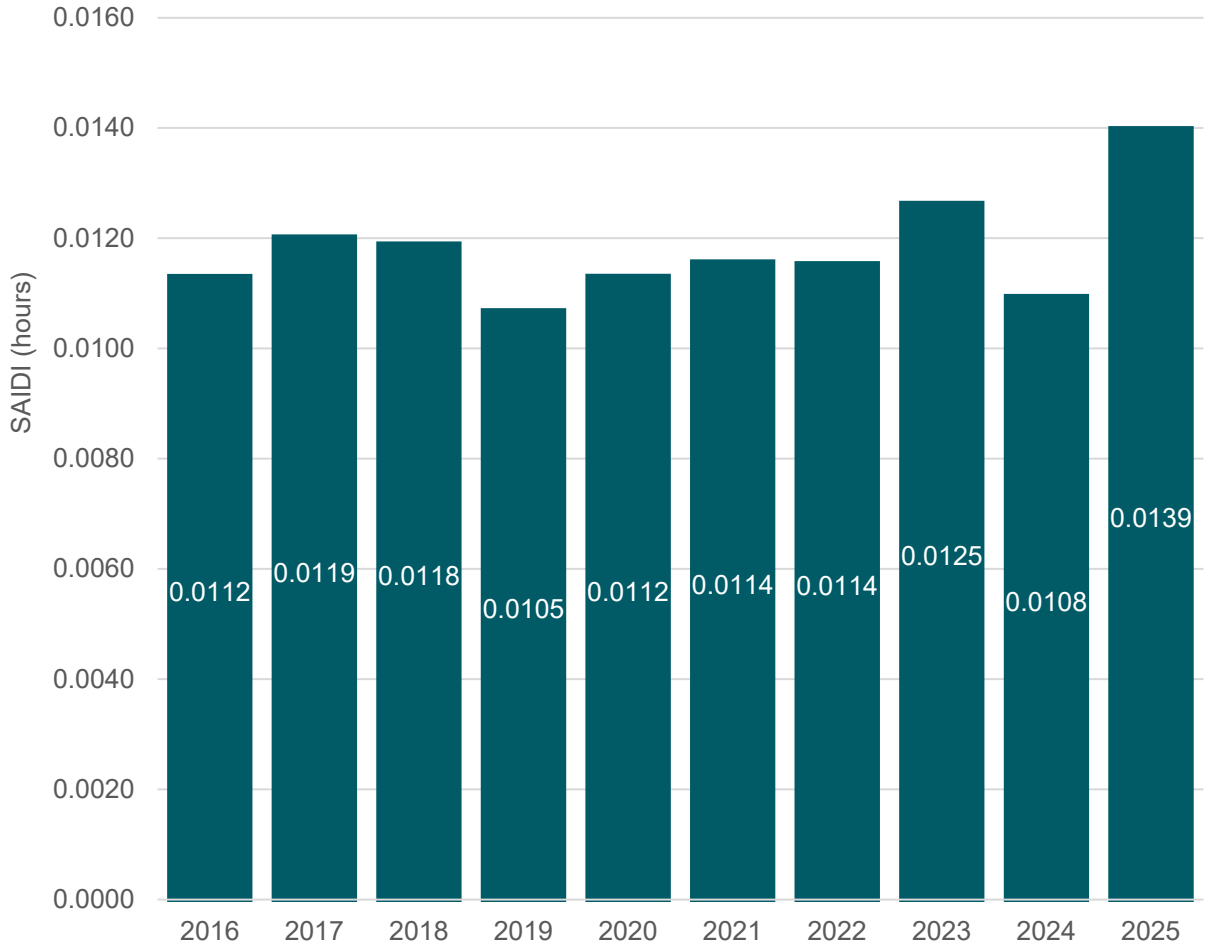


Figure 76: SAIDI Contribution of Interruptions Attributed to Overhead Transformer Failures (Excluding FM)

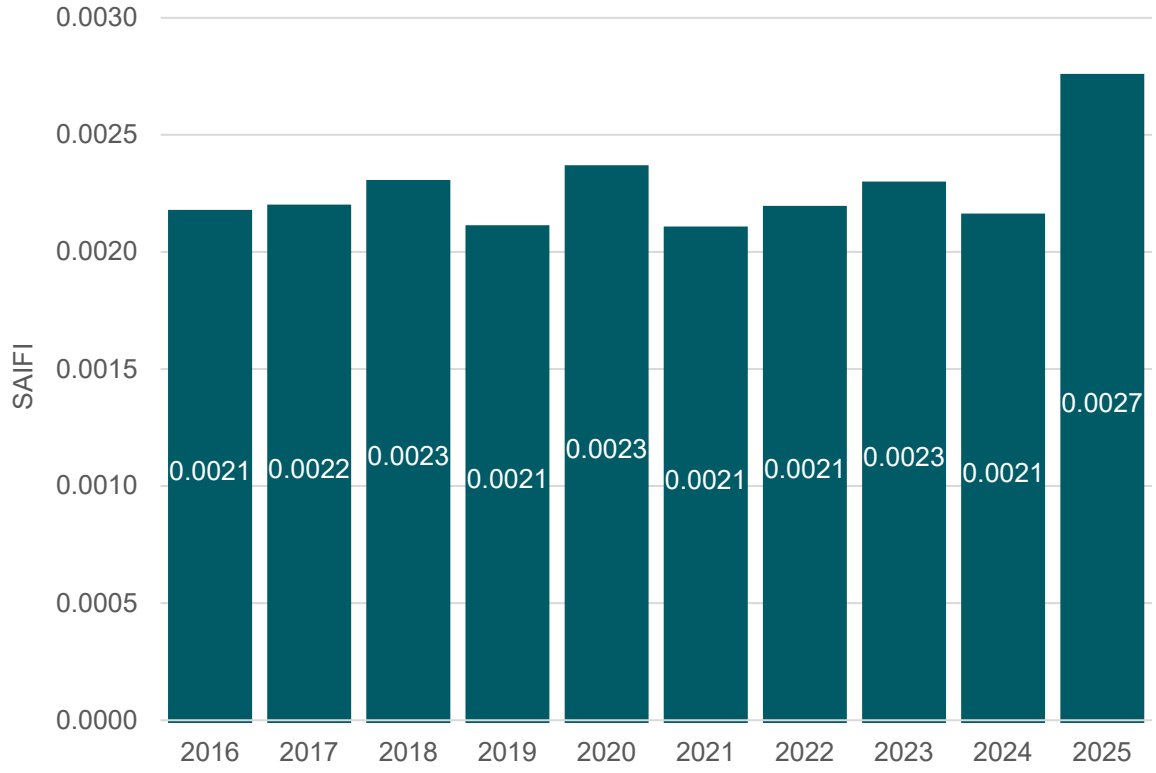


Figure 77: SAIFI Contribution of Interruptions Attributed to Overhead Transformer Failure (Excluding FM)

3.2.3.4.3.2 UNDERGROUND TRANSFORMERS

Figures 78, 79, and 80 provide the number of interruptions, SAIDI and SAIFI contributions attributed to underground transformer failures, excluding interruptions during force majeure events. From 2016 to 2025, there have been an average of 98 interruptions attributed to underground transformer failures per year, with an average annual SAIDI and SAIFI contribution of 0.00254 hours and 0.0007 interruptions, respectively.

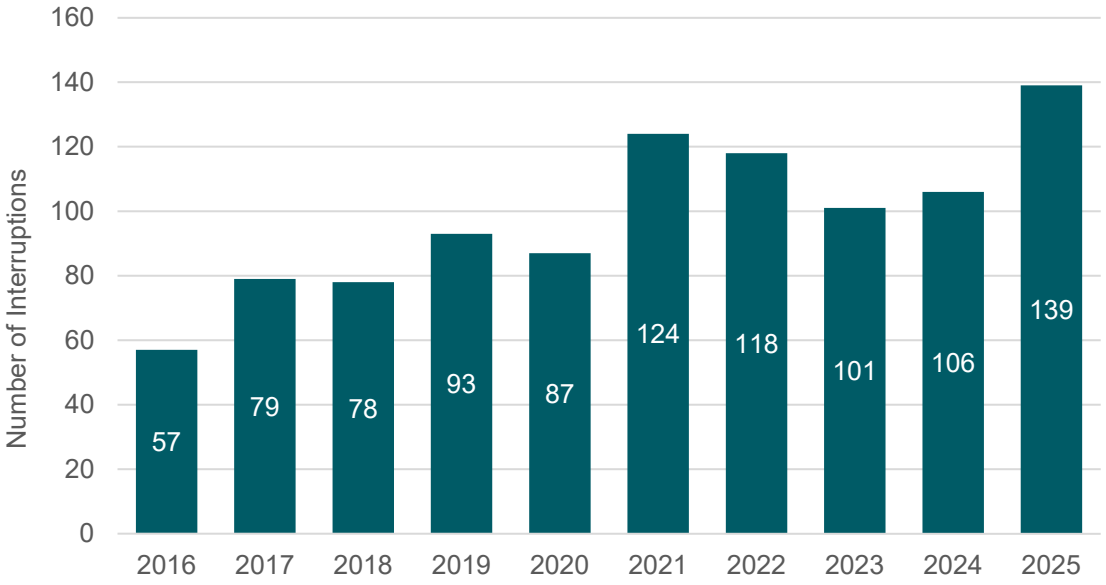


Figure 78: Number of Interruptions Attributed to Underground Transformer Failures (Excluding FM)

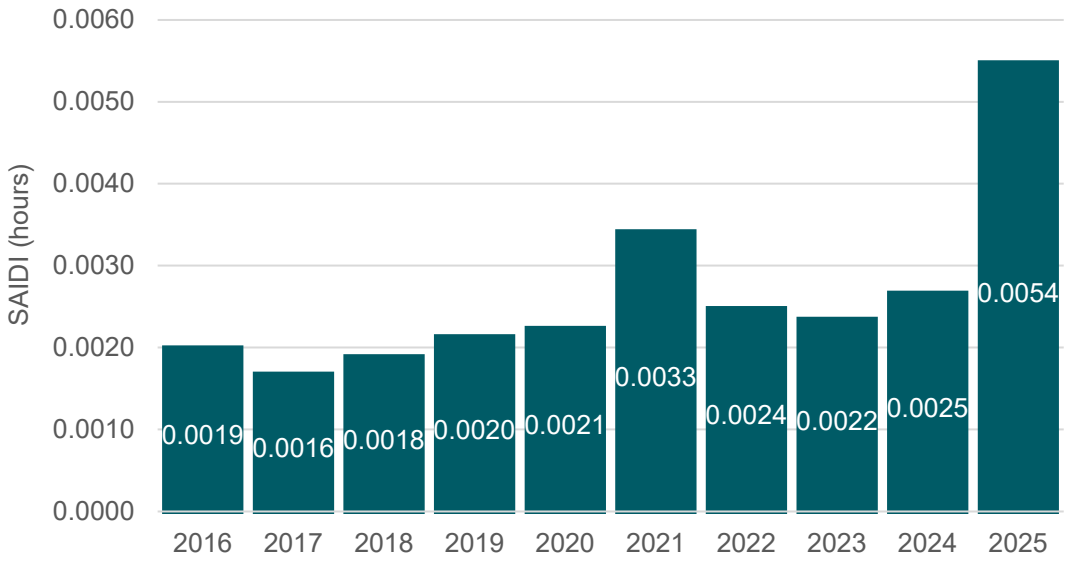


Figure 79: SAIDI Contribution of Interruptions Attributed to Underground Transformer Failures (Excluding FM)

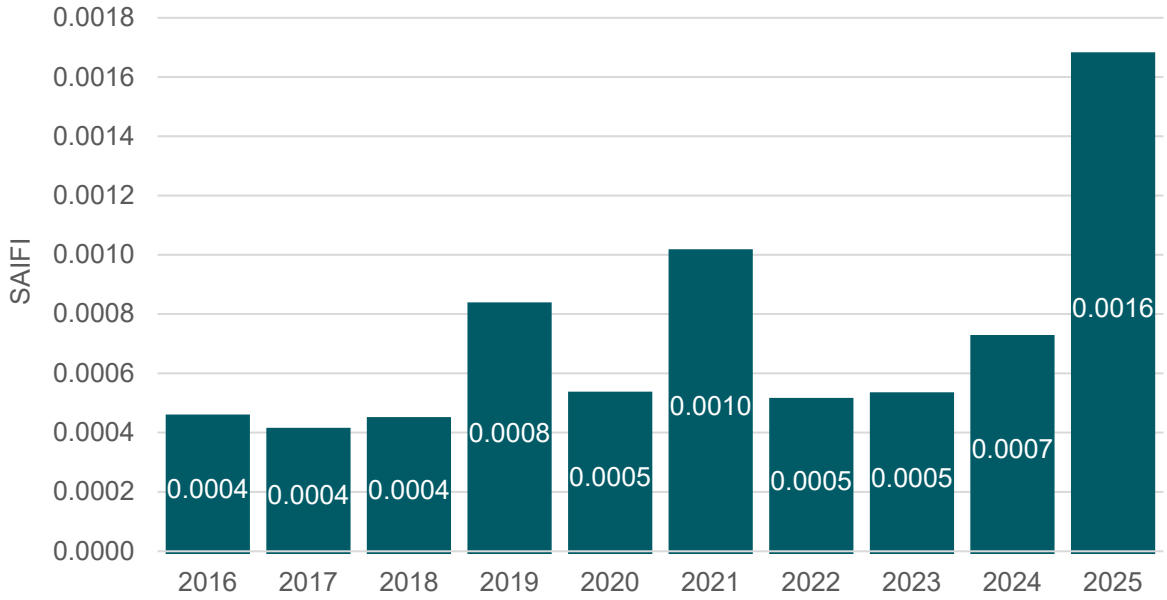


Figure 80: SAIFI Contribution of Interruptions Attributed to Underground Transformer Failures (Excluding FM)

3.2.3.4.4 LIFECYCLE STRATEGY

Distribution line transformers are generally run to failure. These assets are not proactively replaced due to (i) the high cost of assessing their condition relative to replacement, and (ii) the relatively small reliability impact of failure as each of these assets serves a limited number of customers and can be quickly replaced when it fails.

3.2.3.4.4.1 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 patrol program, as discussed in Exhibit E-03-02.

3.2.3.4.4.2 REPLACEMENT & REFURBISHMENT

Distribution line transformers are run to failure, with the following exceptions:

- Transformers that are deemed to be substandard transformers and that pose an unusually high reliability or safety risk, are replaced on a planned basis (see DSP Section 3.11, D-SR-08)
- 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

3.2.3.5.1 ASSET DESCRIPTION / PURPOSE

Hydro One's distribution system includes approximately 114,000 circuit kilometres of overhead distribution lines constructed within approximately 104,000 kilometres of designated rights-of-way ("ROWs"). Vegetation within and adjacent to these ROWs must be managed to maintain appropriate clearance from distribution infrastructure and support safe and reliable system operation.

Trees and other vegetation can contact distribution infrastructure directly or fall onto lines, particularly during adverse weather conditions. Such contacts can damage conductors, poles and other equipment, cause customer interruptions, impede access for restoration activities and create public safety risks. Vegetation management is therefore an important component of the lifecycle management of Hydro One's overhead distribution system.

Hydro One manages these risks through cyclical inspection and vegetation management activities that identify and address vegetation defects, hazard trees and brush within and adjacent to distribution ROWs. The associated vegetation management programs are discussed in further detail in Exhibit E-03-02.

3.2.3.5.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.3.5.2.1 *ASSET DEMOGRAPHICS*

Unlike physical distribution assets, ROWs do not have an age or expected service life. Vegetation-management requirements are instead influenced by the physical configuration of the distribution line, accessibility of the ROW and the surrounding vegetation environment.

Hydro One's approximately 104,000 kilometres of distribution ROW are not homogeneous. The principal characteristics influencing inspection and vegetation-management requirements are described below.

Hydro One's distribution feeders are generally classified as M-class or F-class feeders. M-class feeders generally operate at primary voltages of 27.6kV or greater, while F-class feeders generally operate below 27.6kV, subject to exceptions arising from the historical development of Hydro One's distribution system.

Consistent with Hydro One's distribution standards, M-class feeder ROWs are typically maintained to approximately 6 metres from the line centreline in each direction, compared with approximately 5 metres for F-class feeders. These differences affect the vegetation-management envelope and the amount of vegetation requiring management. Figure 81 shows the distribution of M-class feeders and F-class feeders in Hydro One's grid. Figure 82 and Figure 83 show the distribution of on-road/off-road feeders in Hydro One's grid in the southern/central/eastern parts of the province and the northern part of the province respectively.

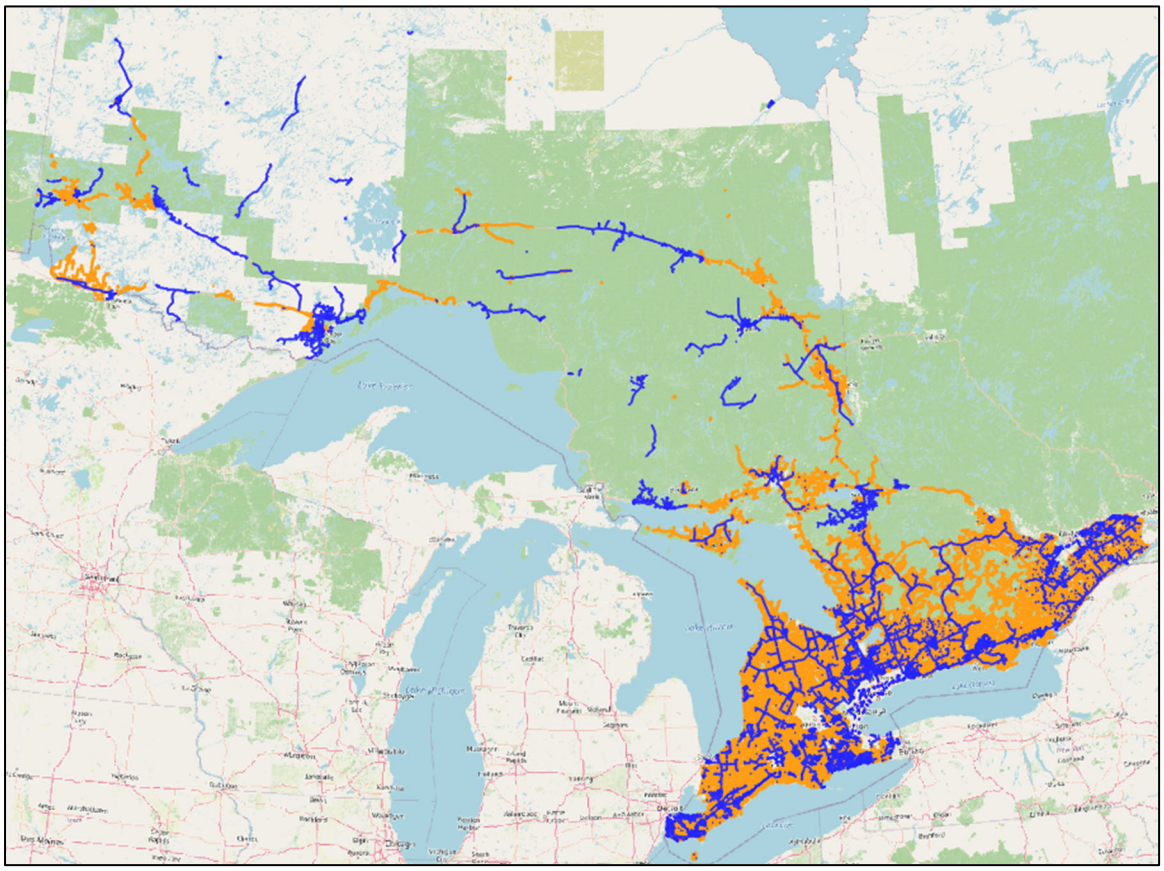


Figure 81: Distribution of M-class Feeders (blue) & F-class Feeders (orange) in Hydro One's Grid

A distribution Right of Way is considered "Off-Road" when it is only accessible by off-road equipment or climbing. These are generally ROWs that are more than 15 meters from the shoulder of a road and require use of a boom truck for trimming trees. Approximately 15% of Hydro One's overhead ROW is Off-road.

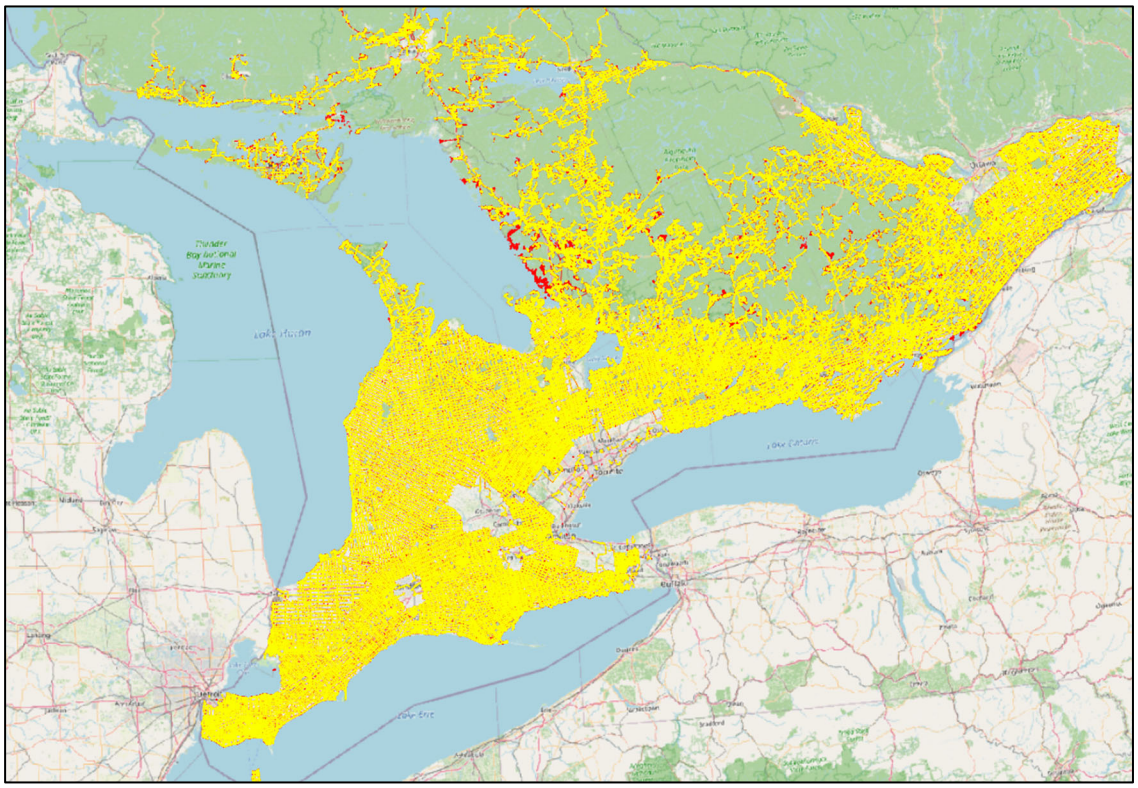


Figure 82: Distribution of On-road (yellow) & Off-road (red) Sections of Feeders in Hydro One's Grid (Southern, Central & Eastern Regions)

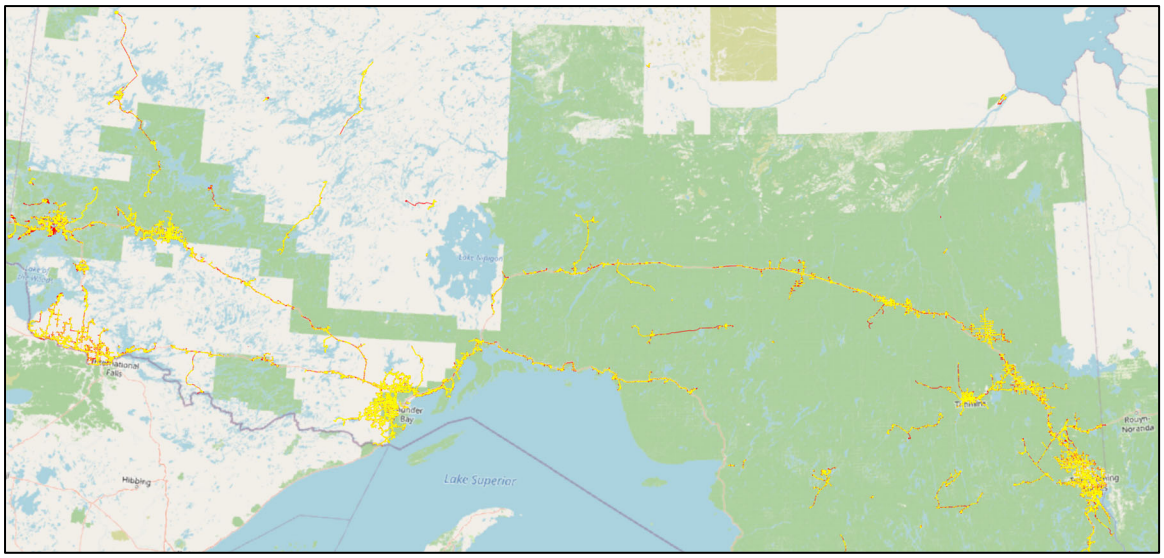


Figure 83: Distribution of On-road (yellow) & Off-road (red) Sections of Feeders in Hydro One's Grid (Northern Region).

Hydro One's distribution ROWs extend across a geographically diverse service territory and traverse different vegetation environments, including boreal, mixed coniferous and deciduous forest areas (see Figure 84). Differences in vegetation type, density and growth conditions contribute to variation in vegetation-management requirements across the system.

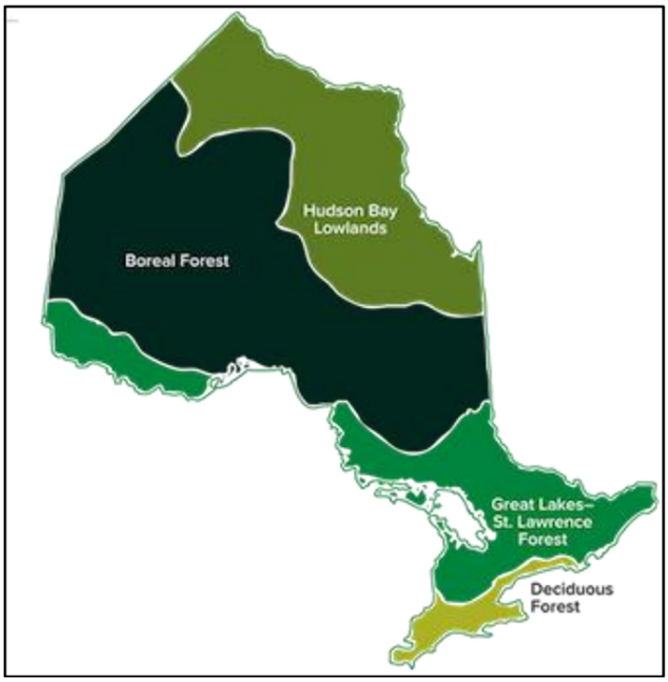


Figure 84: Forest types in Ontario

Collectively, ROW width, accessibility and vegetation characteristics result in differences in the work required to inspect and manage individual ROW sections. Hydro One considers these characteristics in vegetation-management planning and prioritization.

3.2.3.5.2.2 ASSET CONDITION

Because ROWs are not conventional physical assets, their condition is not assessed based on age or a traditional asset health index. Hydro One instead assesses ROW condition using indicators that reflect the extent and characteristics of vegetation requiring management. These include:

- time since the ROW was last cleared;

- vegetation defect density;
- vegetation defect composition;
- presence of hazard trees; and
- brush growth and encroachment.

Vegetation defects include vegetation near energized equipment and trees adjacent to a ROW that have the potential to contact distribution infrastructure because they are dead, diseased, decayed, or structurally unsound. During the 2023-2024 period, about 27% of vegetation defects addressed near distribution lines were located outside of the ROWs, demonstrating that vegetation-related risk is not limited to vegetation located directly beneath the line.

As an example of the vegetation defect, the left side picture in Figure 85 below shows a line section with overgrown trees where the branches are near the power line. In such a case, the branches must be trimmed back to restore clearance from power lines.

The right picture in Figure 85 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 several hours. In severe cases, trees of this size can also damage adjacent poles and equipment. To mitigate this risk, the dead tree near the line needs to be removed.



Figure 85: In-Contact Trim on the Left; Hazard Tree Removal on the Right.

ROW condition generally deteriorates over time following vegetation management activities. As vegetation regrows and adjacent trees age or become affected by disease and environmental factors, the likelihood of tree-caused outages increases. Severe weather events can further damage or weaken trees that do not initially pose a risk to distribution infrastructure but may later develop into hazard trees requiring mitigation.

Hydro One's condition information indicates that an increase in vegetation management is required. OCP[3] observed defect density increased from approximately 21 defects per kilometre in 2021 to approximately 60 defects per kilometre in 2025, an increase of approximately 186% (see Figure 86). The increase in defects is primarily attributed to overgrown brush.

[3] Optimal Cycle Protocol (OCP) was adopted by Hydro One in 2018 as a means of reducing cycle times without increasing the overall cost of the vegetation management program.

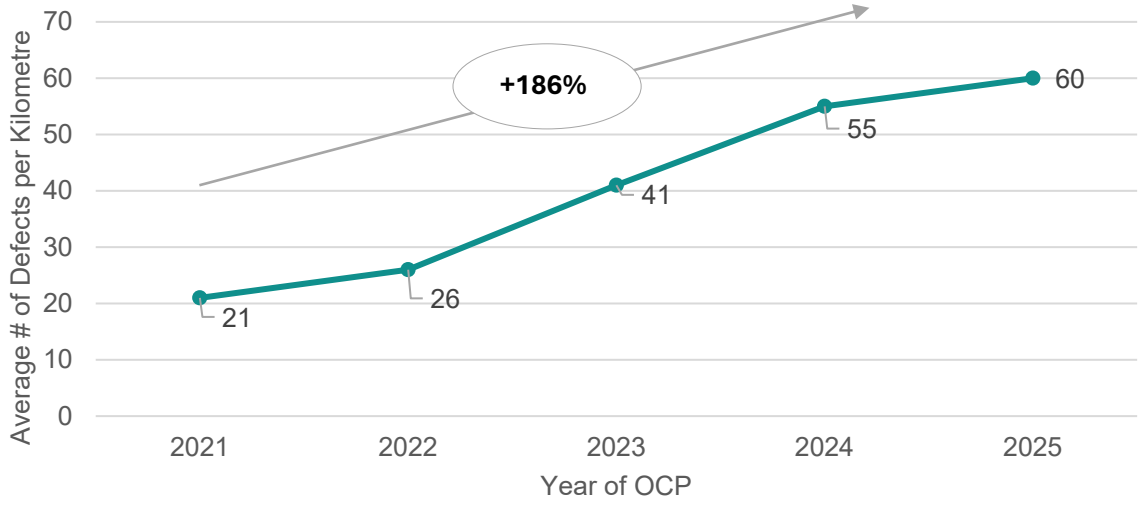


Figure 86: OCP Defect Density (# defects per kilometer) – 2021-2025

The composition of identified vegetation defects has also changed. R0 defects, representing the smallest-diameter tree removals and vegetation similar to brush, increased from approximately 39% of vegetation maintenance work in 2021 to approximately 58% in 2025 (see Figure 87).

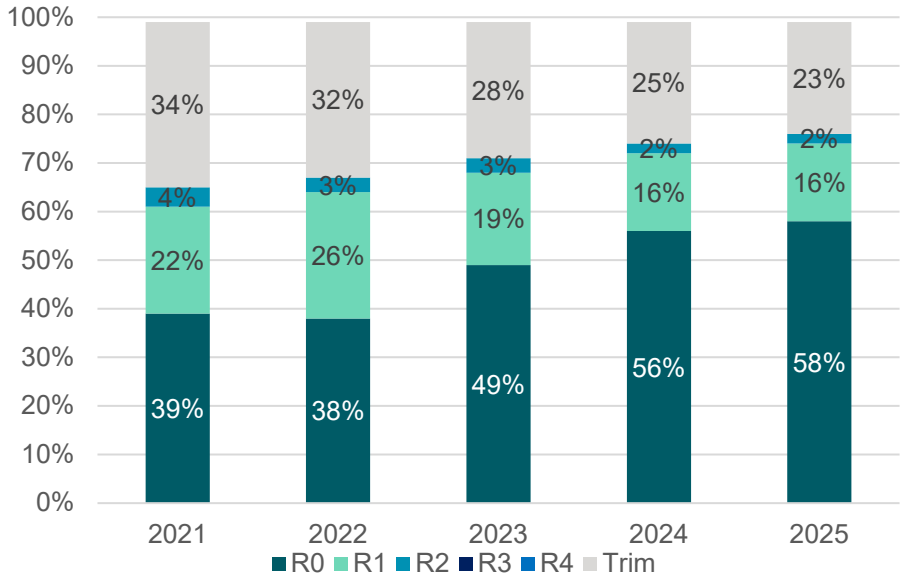


Figure 87: Evolution of Defect Composition Over 2021-2025

The increase in R0 defects is consistent with the accumulation and growth of brush that was not addressed through proactive brush management. As brush grows closer to energized infrastructure, it can transition into vegetation defects requiring more specialized forestry resources and treatment.

The time elapsed since the last vegetation management cycle is also an important indicator of ROW condition. Over 2023-2027, Hydro One expects to complete an average of 9,612 kilometers of OCP work annually. Relative to 104,000 kilometers of distribution ROW, this corresponds to an average vegetation management cycle of 10.8 years. Figure 88 reports the time since last clearance for all ROW kilometers.

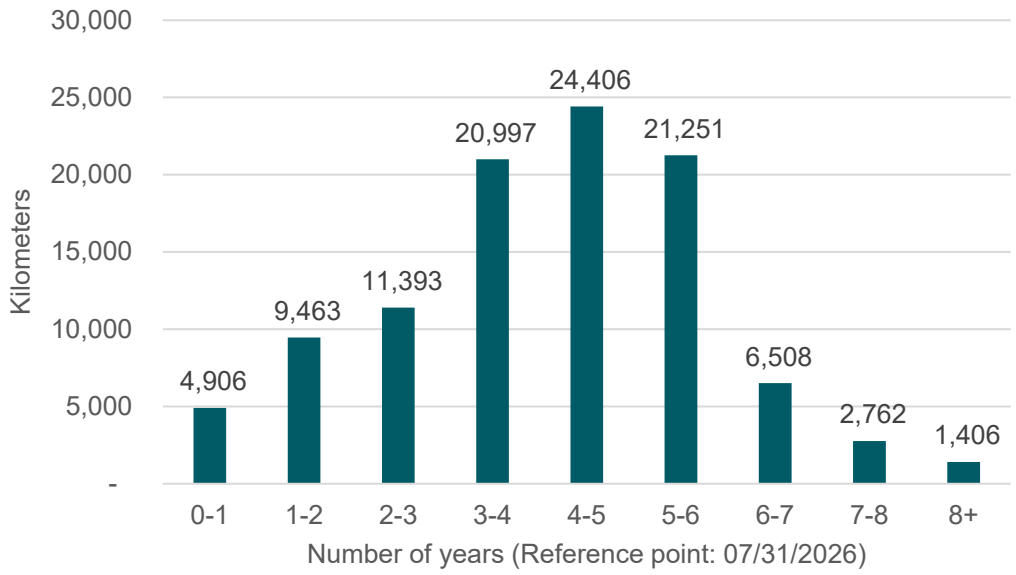


Figure 88: Time since last Clearance on ROW Kilometers

Hydro One has observed that vegetation defect density generally increases as the time between clearing cycles increases. Longer cycles therefore result in greater vegetation-management requirements when crews return to a ROW and increase the period during which vegetation defects may develop.

3.2.3.5.2.3 ASSET PERFORMANCE

Vegetation is a material contributor to distribution system interruptions. Hydro One monitors tree-caused outages, SAIDI, SAIFI and customer outage hours to assess vegetation-related system performance.

Hydro One introduced the Optimal Cycle Protocol (OCP) in 2018. OCP shifted vegetation management from a predominantly corridor-based approach to one focused on identifying and addressing vegetation defects requiring treatment. Following implementation of OCP, the number of ROW kilometres managed increased and vegetation-related reliability performance generally improved.

More recently, vegetation-related reliability performance has deteriorated. Beginning in 2023, the kilometers executed on a yearly basis began to decrease due to unanticipated levels of overgrown vegetation and reprioritization to address emergent demand-driven work in other programs, as further detailed in Exhibit E-03-02. The number of ROW kilometres completed declined from approximately 14,296 kilometres in 2023 to 12,340 kilometres in 2024 and 7,623 kilometres in 2025 (see Figure 89).

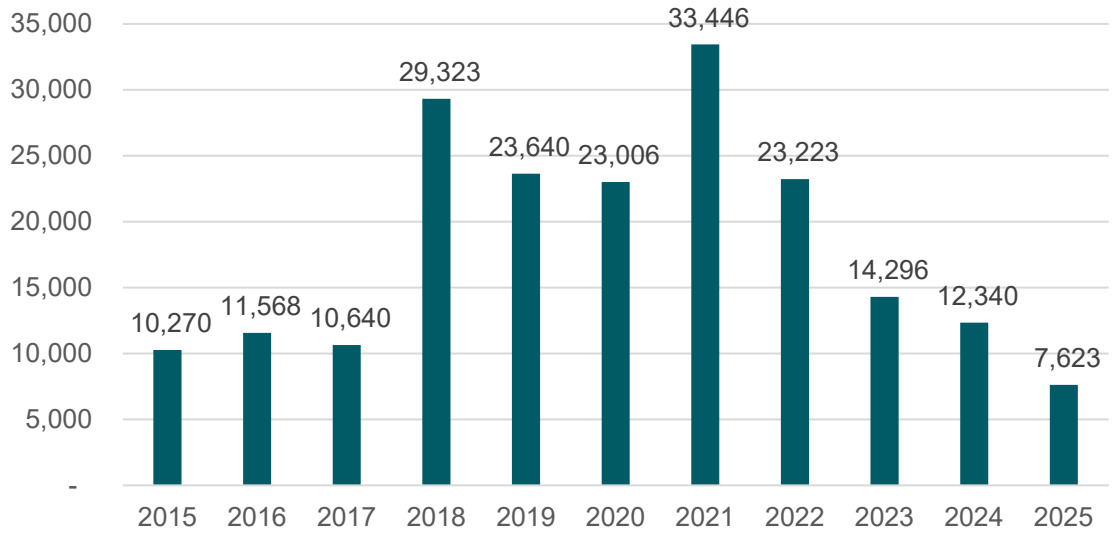


Figure 89: Number of ROW kilometers executed per year prior to OCP (Pre 2018) and since OCP implementation (2018 & beyond)

Over the same period, excluding Major Event Days (MED) as defined by IEEE 1366 2.5Beta methodology:

- tree-caused SAIDI increased from approximately 2.34 hours in 2023 to 3.36 hours in 2025;
- tree-caused SAIFI increased from approximately 0.52 interruptions in 2023 to 0.72 interruptions in 2025;
- tree-caused outages increased from approximately 7,894 in 2023 to 10,782 in 2025; and
- tree-caused customer outage hours increased from approximately 3.4 million hours in 2023 to approximately 5.1 million hours in 2025.

Figures 90 and 91 below show a general improvement in tree-caused SAIDI and SAIFI following the start of OCP (excluding interruptions during Force Majeure (FM) events). However, this trend starts to reverse in 2024. The recent deterioration in vegetation-related reliability performance is consistent with the observed increase in vegetation defect density, longer vegetation-management cycles, and increasing adverse weather.

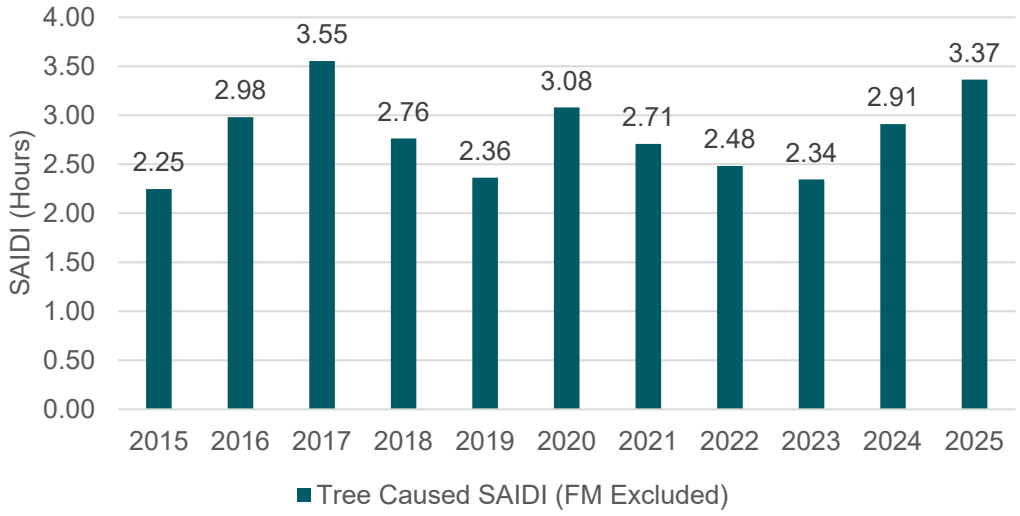


Figure 90: Tree Caused SAIDI Contribution with Force Majeure (FM) Events Excluded[4]

[4] This figure shows the cumulative SAIDI due to tree-contacts during blue sky and adverse weather events. Beginning 2023, all non-FM tree-caused outages were divided into those caused during adverse weather events, and those during days where weather was not a significant factor. Chart shown in this format to be comparable to pre-2023 years.

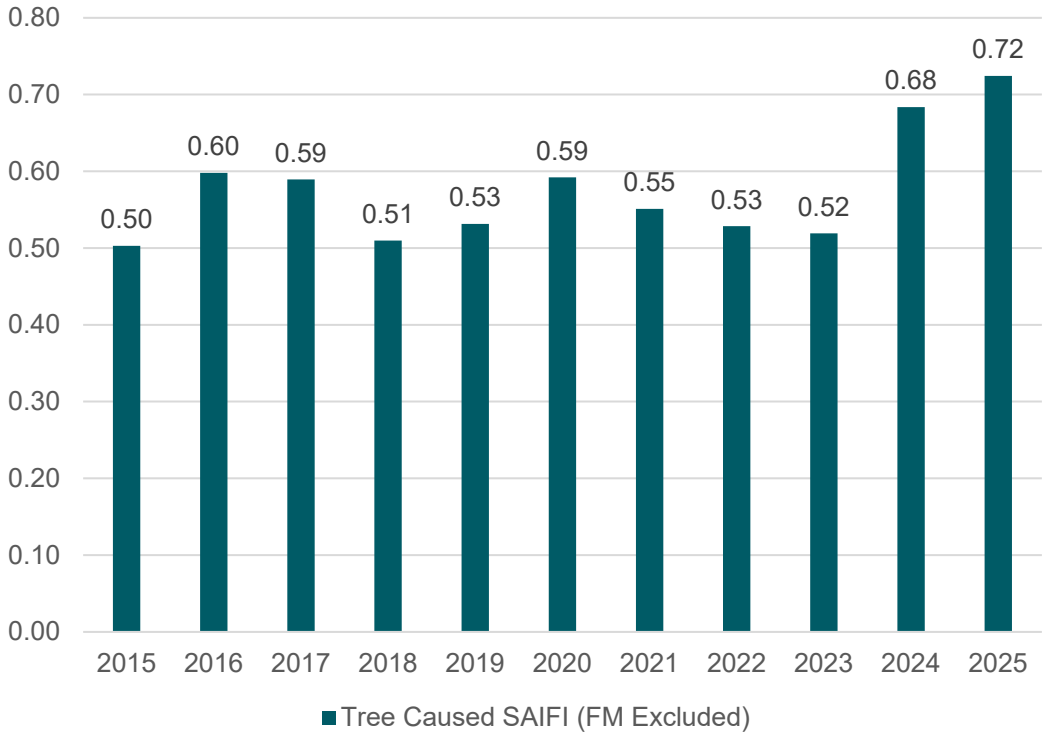


Figure 91: Tree Caused SAIFI Contribution with FM Events Excluded[5]

To reverse these trends, Hydro One has proposed increasing its vegetation management and brush work activities beginning in 2028, as discussed further in Exhibit E-03-02. The program will leverage advanced vegetation management practices, including data-driven approaches and remote sensing technologies, to more effectively target vegetation risks and optimize work planning. By improving the overall condition of the ROW, the program is expected to enhance worker access, reduce future maintenance costs, and support improved safety and reliability outcomes.

3.2.3.5.3 LIFECYCLE STRATEGY

Hydro One manages its distribution ROWs through an integrated, cyclical and risk-informed vegetation management strategy. Unlike conventional physical assets, ROWs

[5] This figure shows the cumulative SAIFI due to tree-contacts during blue sky and adverse weather events. Beginning 2023, all non-FM tree-caused outages were divided into those caused during adverse weather events, and those during days where weather was not a significant factor. Chart shown in this format to be comparable to pre-2023 years.

are not renewed through replacement. Their condition is maintained through recurring inspection and vegetation treatment to maintain appropriate clearances from energized infrastructure, control vegetation growth, address hazard trees, preserve access to distribution facilities, and manage vegetation-related reliability and public safety risk.

ROW condition changes continuously as vegetation grows and as trees within and adjacent to the ROW are affected by maturity, disease, pests, weather and other environmental conditions. The timing and extent of vegetation management are therefore important lifecycle considerations. As the period between interventions increases, vegetation density and defect levels can increase, and the amount and complexity of work required during the subsequent intervention can also increase.

Hydro One's ROW lifecycle strategy combines three complementary approaches:

1. **cyclical vegetation management through OCP Flex**, which provides the principal framework for inspecting ROWs, assessing vegetation-related risk and prescribing work, as further described below;
2. **proactive brush management**, which controls lower-growing woody vegetation before it develops into vegetation defects requiring more specialized treatment; and
3. **targeted treatment of localized higher-risk areas through the Outliers approach**, which provides targeted vegetation treatment in locations where localized conditions result in elevated vegetation-related reliability risk that is not sufficiently addressed through the normal cyclical approach.

These approaches are supported by other activities in Hydro One's Public Safety and Reliability program, as well as by Quality Assurance and Quality Control activities, which address vegetation-related issues arising outside the planned work cycle and provide assurance that vegetation-management work is completed in accordance with applicable requirements and specifications. Further details regarding these programs, associated work volumes and expenditures are provided in Exhibit E-03-02.

3.2.3.5.3.1 EVOLUTION OF THE ROW LIFECYCLE STRATEGY

Hydro One has progressively refined its vegetation management approach based on vegetation condition, reliability performance and experience implementing its existing programs.

3.2.3.5.3.1.1 OCP TO OCP FLEX

Hydro One introduced the OCP in 2018, transitioning from a predominantly corridor-clearing approach to a defect-driven approach focused on identifying and treating vegetation that could affect distribution infrastructure. OCP improved the targeting of vegetation management work and contributed to improvements in vegetation-related reliability and vegetation management unit costs.

Experience implementing OCP has also demonstrated that vegetation condition and risk vary materially across Hydro One's service territory. Vegetation growth, accessibility, reliability consequences, weather exposure and other local conditions can differ significantly between and within feeders. Accordingly, applying relatively standardized work prescriptions at the feeder level does not fully reflect the conditions and risks present at individual ROW sections.

Hydro One is transitioning OCP to an enhanced approach referred to as OCP Flex. OCP Flex retains the cyclical and defect-management principles of OCP while introducing a more granular, condition- and risk-informed approach to determining where and to what extent vegetation management work is required.

For ROW sections selected for treatment, OCP Flex will use two components of work prescription. Base prescriptions will address vegetation required to maintain appropriate reliability and public safety conditions. Flexible prescriptions will allow additional vegetation to be addressed where warranted to proactively manage future defects, taking into account local conditions, anticipated return-to-site intervals and other relevant constraints. This provides Hydro One with the ability to vary the intensity of vegetation treatment rather than applying a uniform prescription across the distribution system.

Cycle length remains an important element of the lifecycle strategy. Hydro One's long-term objective is to achieve an average return-to-site cycle of approximately five years. Over the 2028–2032 period, the proposed vegetation management plan is expected to progressively move ROWs toward this objective, with an average return-to-site cycle of approximately 6.6 years over the period. OCP Flex also allows treatment intervals and prescriptions to be adjusted where the risk assessment indicates that a different approach is appropriate.

OCP Flex is being introduced during 2026-2027 (Phase 1), with full deployment planned for 2028 (Phase 2). This phased implementation provides an opportunity to incorporate operating experience and refine vegetation data, work prescriptions and planning processes prior to full-scale implementation during 2028-2032.

3.2.3.5.3.1.2 ENHANCED BRUSH MANAGEMENT

Brush management is a preventive component of Hydro One's ROW lifecycle strategy. It is intended to control woody vegetation within the ROW while it remains relatively small and before it grows into the energized line environment.

Hydro One's ability to complete planned brush management has been constrained during prior vegetation management cycles. During the first OCP cycle, higher than anticipated vegetation defect densities required resources planned for brush management to be reallocated to tree trimming and removals. Together with subsequent reprioritization of planned work, these factors delayed brush control and contributed to increasing vegetation defect densities. It also prevented the application of herbicide following brush control, allowing vegetation to regrow more rapidly.

Hydro One is increasing the role of proactive brush management during the 2028–2032 period. The enhanced approach is intended to address brush earlier in its growth cycle and reduce the rate at which lower-growing vegetation develops into larger or line-proximity defects requiring more specialized forestry resources.

Brush treatment will include mechanical and manual clearing and, where permitted and appropriate, the targeted and controlled application of herbicides following clearing to limit regrowth and extend the effectiveness of the initial treatment. Compatible low-growing vegetation may also be established where appropriate to limit future woody vegetation growth. This approach recognizes that clearing vegetation without effectively managing regrowth can result in the ROW returning more quickly to an overgrown condition. The targeted use of herbicides is therefore an important element of the 2028–2032 brush management strategy.

Hydro One will use a risk-based approach to prioritize brush-management locations. Factors considered may include accessibility, vegetation characteristics, outage and restoration history, span characteristics and local forestry knowledge. This represents a shift toward recognizing proactive brush management as an integral component of maintaining ROW condition over the long term.

3.2.3.5.3.1.3 TARGETED TREATMENT OF LOCALIZED HIGHER-RISK AREAS THROUGH THE OUTLIERS APPROACH

Hydro One developed an Outliers Program and began broader implementation in 2024 to address locations experiencing elevated frequency and consequences of tree-caused outages.

The Outliers Program supplements Hydro One's cyclical vegetation-management program. While OCP and OCP Flex provide a system-wide framework for managing vegetation, certain locations are subject to local characteristics that can result in vegetation-related risks materially different from those captured through standard vegetation-management prescriptions.

These characteristics can include exposure to prevailing wind corridors, proximity to lakes, local forest conditions, storm exposure and other site-specific ecological factors.
Under the Outliers Program, Hydro One identifies distribution sections with elevated vegetation-related outage frequency and consequences. Specialized forestry personnel then use local knowledge and field assessment to identify additional vegetation treatment

that may be warranted beyond the work prescribed through the cyclical program. Work is coordinated with OCP/OCP Flex schedules to avoid unnecessary duplication.

Early program experience indicates reductions in interruptions on treated sections during both blue-sky and storm days. Hydro One plans to continue the Outliers Program during the 2028-2032 period as a targeted complement to OCP Flex.

3.2.3.5.3.2 INSPECTION & MAINTENANCE PRACTICES

Hydro One implements the ROW lifecycle strategy through recurring vegetation inspection, condition and risk assessment, and vegetation treatment.

Vegetation inspections identify conditions within and adjacent to ROWs, including vegetation approaching or contacting required clearances, dead, diseased, decayed or structurally unsound trees with the potential to contact distribution infrastructure, brush requiring treatment, and other conditions relevant to vegetation-related risk.

Under OCP Flex, inspection information will be used both to identify existing vegetation defects and to support the determination of the appropriate work prescription for the ROW section. Field information will increasingly be supplemented by remote sensing and other data sources where these improve Hydro One’s understanding of vegetation condition and risk.

Vegetation treatment includes tree trimming, hazard-tree removal, brush clearing and associated vegetation-control activities. The timing and scope of treatment will reflect observed vegetation condition, location-specific risk, accessibility and the anticipated period before the next intervention.

Vegetation located near energized infrastructure and hazard trees that have the potential to contact distribution facilities is addressed through the cyclical OCP Flex program. Treatment is based on the condition and risk identified through inspection rather than on the age of the ROW.

Proactive brush management is used to control lower-growing woody vegetation before it develops into vegetation defects. Where appropriate, follow-up treatment is used to reduce regrowth and extend the effectiveness of the initial clearing activity.

The Outliers Program provides additional treatment in selected higher-risk locations where local conditions warrant work beyond that prescribed through the cyclical program.

Together, these inspection and maintenance practices allow Hydro One to manage ROW condition on an ongoing basis, with the nature and timing of treatment reflecting vegetation growth, observed condition and location-specific risk.

3.2.4 ASSET COMPONENT INFORMATION – WHOLESALE REVENUE & RETAIL REVENUE METERS

3.2.4.1 METERS

3.2.4.1.1 ASSET DESCRIPTION / PURPOSE

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.

3.2.4.1.1.1 WHOLESALE REVENUE METERS

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.

3.2.4.1.1.2 RETAIL REVENUE METERS

Retail revenue meters measure electricity consumption for approximately 1.5 million Hydro One customers. Retail meters form part of Hydro One's Advanced Metering Infrastructure (AMI), which includes smart meters, access points, relays, 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.

3.2.4.1.2 ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

3.2.4.1.2.1 ASSET DEMOGRAPHICS

3.2.4.1.2.1.1 WHOLESALE REVENUE METERS

Hydro One operates approximately 860 wholesale revenue meters across approximately 430 WRMIs. Approximately 43% (371 meters) are 10 years of age or less while the remaining 57% (489 meters) are between 11-20 years of age. Figure 92 provides an overview of the age demographics of Hydro One's WRMI meters.

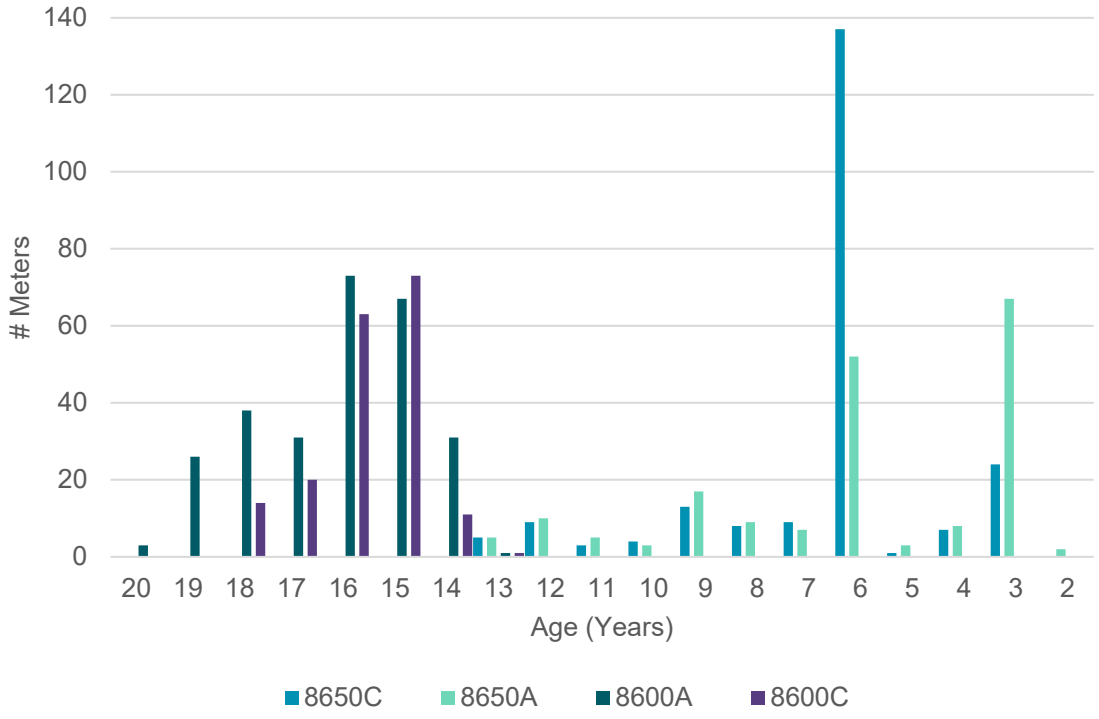


Figure 92: Wholesale Meter Age Distribution

WRMIs also include approximately 1,725 instrument transformers. Instrument transformers generally have substantially longer service lives than electronic revenue meters and Hydro One's population includes a broad range of manufacturers, technologies and ages Approximately 61% of the population is 20 years of age or less, while a smaller portion of the population has been in service for more than 40 years. Figure 93 provides an overview of the age demographics of Hydro One's WRMI instrument transformers.

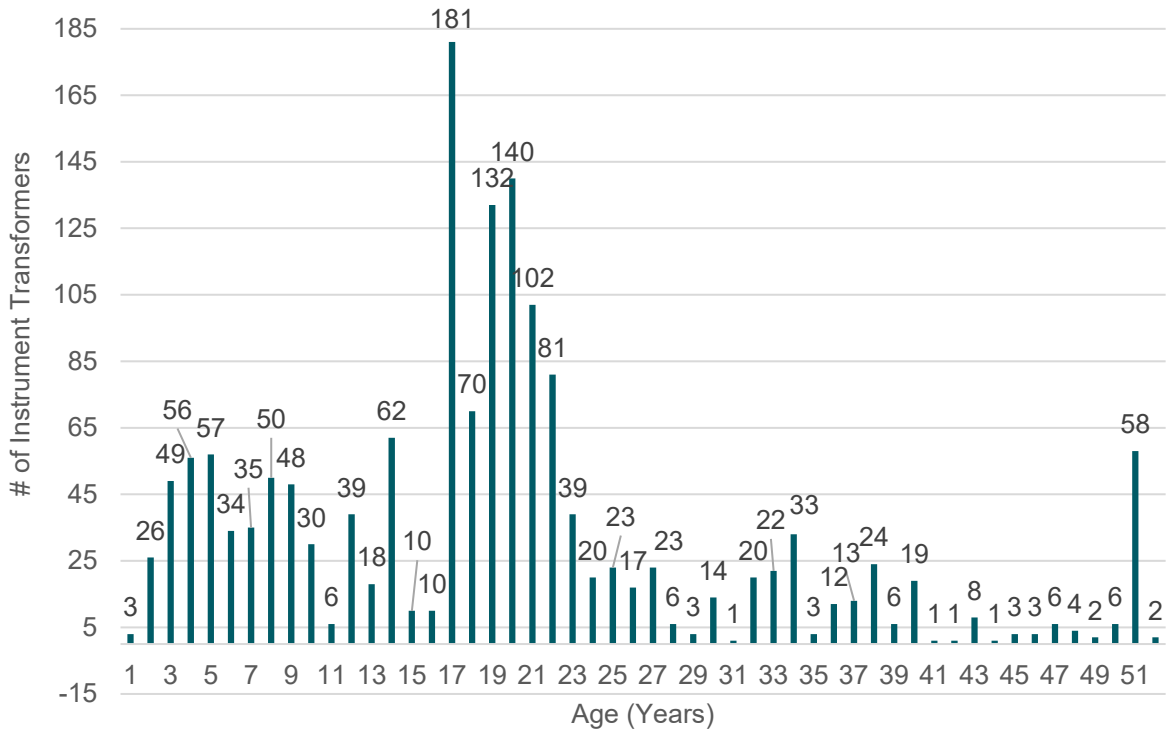


Figure 93: WRMI Instrument Transformer Age Profile

3.2.4.1.2.1.2 RETAIL REVENUE METERS

Hydro One began deploying its first-generation AMI system ("AMI 1.0") in 2007. Following approval to replace the aging AMI 1.0 system, Hydro One commenced deployment of its second-generation AMI system ("AMI 2.0") in 2025.

Hydro One currently operates approximately 1.5 million retail revenue meters together with the communications network equipment required to support the AMI system. The existing meter population includes equipment from several vendors as a result of the original AMI deployment and subsequent LDC acquisitions. The majority of the installed population uses the Trilliant AMI system. As AMI 2.0 is deployed, Hydro One will progressively transition the retail meter population and associated communications network to the new Itron-based solution.

Approximately 758,000 retail meters, representing approximately 50% of the installed meter population, were at or beyond the 15-year service life of the AMI 1.0 meters as of year-end 2025. Figure 94 below provides the age distribution of meters by year and vendor for the meter population.

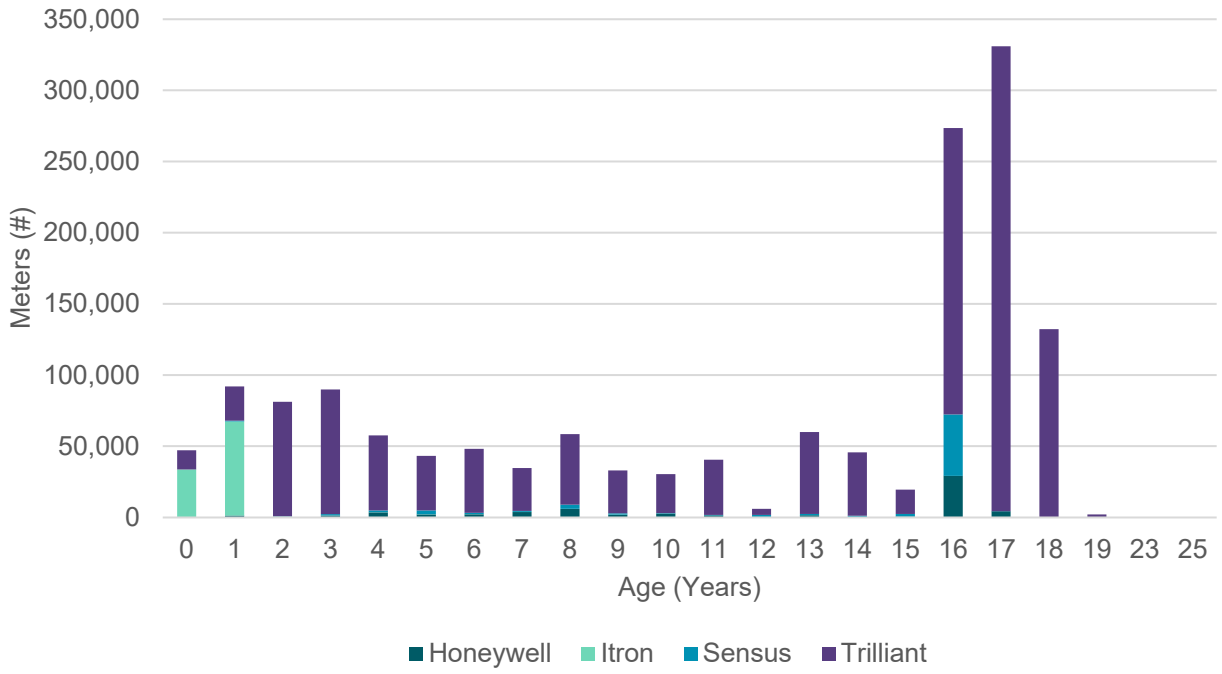


Figure 94: Meter Age Distribution by Year/Vendor (as of 2025)

3.2.4.1.2.2 ASSET CONDITION

Unlike many mechanical and electrical distribution assets, the internal physical condition of electronic revenue meters cannot be practically assessed through routine inspection or diagnostic testing. Meter health is therefore assessed primarily using age, equipment performance and failure history, together with manufacturer service-life information, regulatory compliance requirements, availability of vendor support and technological obsolescence.

3.2.4.1.2.2.1 WHOLESALE REVENUE METERS

Electronic wholesale revenue meters are generally reliable and can be replaced relatively quickly when failures occur. Instrument transformers, however, have different failure characteristics and consequences. Instrument transformer failures can affect the accuracy and availability of a WRMI and, depending on the installation, may require a station outage or other operational measures to complete corrective work.

Hydro One has identified a particular performance concern associated with certain ABB instrument transformer models. ABB instrument transformers account for approximately 56% of the instrument transformer failures identified in Hydro One's failure history, with the affected population failing at an average age of approximately 13 years. The principal affected models are ABB KOR current transformers and VOZ and VOY voltage transformers.

Figure 95 and Table 17 provide the total incidence of instrument transformer failures between 2015 and 2025. There has been a trend of increasing ABB instrument transformer failures with eight ABB WRMIs failing in 2020 alone.

Table 17 - Instrument Transformer Failures by Manufacturer

Manufacturer	Average Failure Age	Count of IT Failed	% of Total Failures
General Electric	50	8	4
Westinghouse	40	3	2
Trench Electric	14	12	7
Asea Brown Boveri	13	99	56
Ferranti Packard	46	15	8
Sadtem	13	19	11
Associated Eng	21	3	2
Ritz	11	3	2
Arteche	5	10	6
Kuhlman Electric	19	6	3

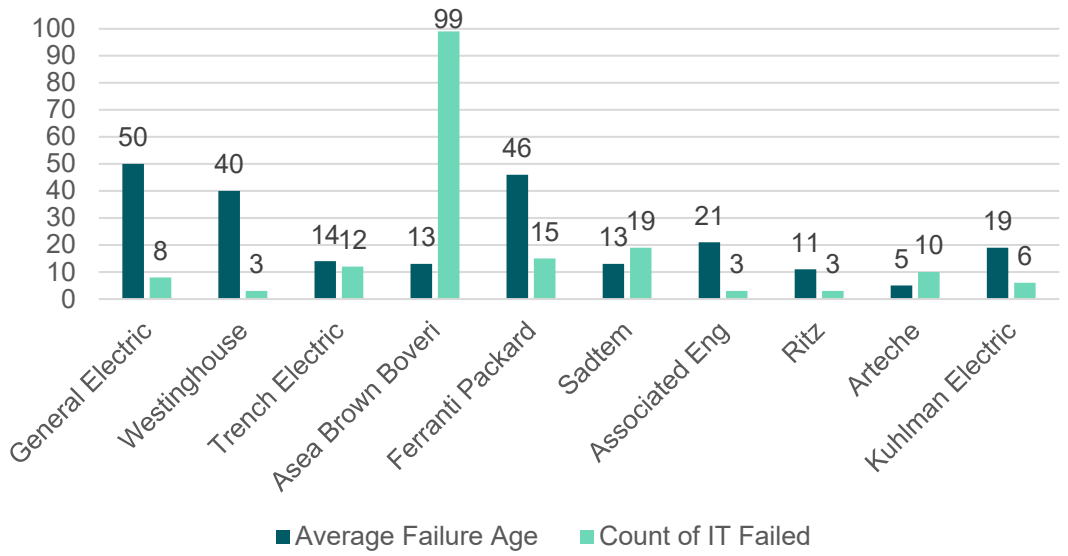


Figure 95: Number of Instrument Transformer Failures at Age of Failure

As an example, Figure 96 below provides photographs of certain failed instrument transformers.

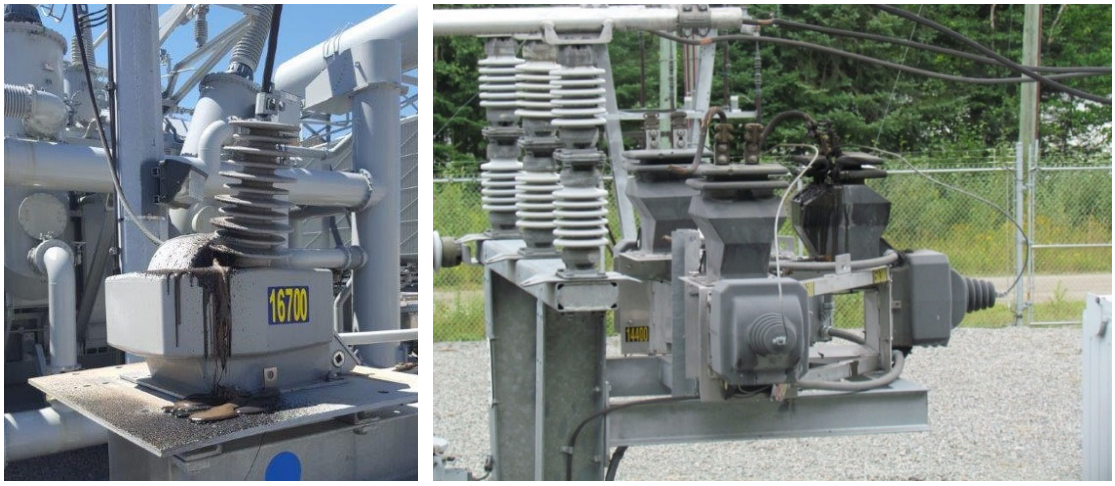


Figure 96: Failed Instrument Transformers

Hydro One has identified 42 WRMIs employing these ABB instrument transformer models. Based on the concentration of failures within these meter models and the observed average age at failure, Hydro One plans to proactively replace the affected models that

are older than 10 years during 2028-2032 period rather than continuing to manage this specific population solely on a run-to-failure basis.

3.2.4.1.2.2.2 RETAIL REVENUE METERS

Meter age and meter failures are key indicators of the health of the retail revenue meter population. Between 2022 and 2025, approximately 181,000 retail meter failures were recorded, equivalent to approximately 12% of the total meter population. Figure 97 presents the annual volume of meter failures.

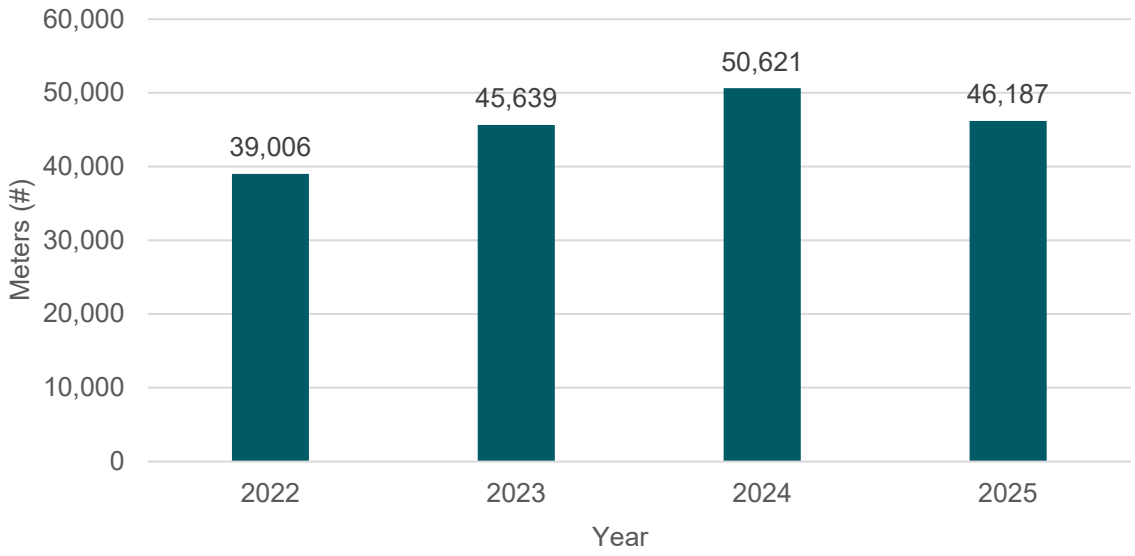


Figure 97: Meter Failures by Year (2022-2025)

Annual meter failures increased from approximately 39,000 in 2022 to approximately 51,000 in 2024 before declining to approximately 46,000 in 2025. While current failure levels are lower than previously anticipated, failures remain elevated as a significant portion of the AMI 1.0 population approaches or exceeds its expected service life.

Meter lifecycle assessments also consider technological obsolescence and continued vendor support, as these factors can affect Hydro One's ability to economically maintain or replace particular meter types.

As AMI 2.0 meters progressively replace the aging AMI 1.0 population, the overall age profile of the retail meter fleet will become younger, and the population is expected to transition to a normal service life phase characterized by lower and more stable failure rates.

3.2.4.1.2.3 ASSET PERFORMANCE

Hydro One monitors metering performance using measures appropriate to the function of its wholesale and retail metering systems. Meter and communication failures can affect the timely collection of settlement and billing data, and can also result in additional field activity where equipment must be replaced or meter readings must be obtained manually.

3.2.4.1.2.3.1 WHOLESALE REVENUE METER

The performance of WRMIs is measured primarily by “Successful Daily Meter Communication”. This measure reflects the combined performance of the communication network, meters and other WRMI components and Hydro One’s ability to address equipment issues in a timely manner.

In 2025, Hydro One achieved average Successful Daily Meter Communication of 93%, compared with a target of 90%. Hydro One will continue to monitor this measure, together with equipment failure information, as the WRMI asset population ages.

Performance of individual instrument transformers is principally monitored through equipment failures and inspection results rather than through a separate system-level performance measure.

3.2.4.1.2.3.2 RETAIL REVENUE METERS

The principal performance requirement for the retail AMI system is the reliable collection of accurate meter data to support customer billing. The performance of the AMI system is measured primarily by billing accuracy, defined as 98% or higher based on the number of accurate bills issued divided by total number of bills, in the OEB Distribution System

Code.[6] 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.

Field work associated with meter issues increased from approximately 31,000 activities in 2021 to approximately 41,000 in 2025, an increase of over 30%. This provides an indication of the operational impact associated with managing the aging AMI 1.0 meter population, including individual meter replacements and unscheduled manual meter reading.

As AMI 2.0 replaced the aging AMI 1.0 meter population, Hydro One expects end-of-life related meter failures and the associated field interventions to decline. This decline in failure-related activity will lower the risk of inaccurate bills.

3.2.4.1.3 LIFECYCLE STRATEGY

Hydro One applies different lifecycle strategies to wholesale revenue meters, instrument transformers and retail revenue meters based on their asset characteristics, regulatory requirements, failure consequences and the economics of repair or replacement.

3.2.4.1.3.1 INSPECTION & MAINTENANCE PRACTICES

3.2.4.1.3.1.1 WHOLESALE REVENUE METERS

Hydro One maintains WRMIs through a combination of regulatory accuracy verification, preventive inspection and corrective maintenance.

Revenue meters are subject to applicable Measurement Canada accuracy and verification requirements. Meters are tested for accuracy on prescribed schedules and, based on the results, are either permitted to remain in service or are removed from service.

WRMIs are also inspected for physical deficiencies, including rust, corrosion, physical damage, loose or damaged connections and indications of overheating. Hydro One also

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

verifies that current transformers continue to measure electrical current correctly. Corrective maintenance is undertaken where equipment deficiencies or failures are identified, subject to applicable IESO Market Rules and metering standards.

Instrument transformers are generally maintained and replaced based on observed condition and performance. Where failure history identifies a broader model-specific reliability concern, Hydro One may undertake targeted proactive replacement. This approach is being applied to the identified ABB instrument transformer population based on the failure experience described above.

3.2.4.1.3.1.2 RETAIL REVENUE METERS

Retail revenue meters are managed in accordance with Measurement Canada verification requirements and monitored using meter age, performance and failure information. 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 unless its seal period is extended through the applicable compliance testing or the meter is replaced. Hydro One therefore undertakes meter sampling and reverification activities as part of the meter lifecycle strategy to maintain compliance with Measurement Canada requirements and ensure continued billing accuracy.

Because electronic meters are sealed devices and individual internal assessment or repair is generally not economic, failed retail meters are normally replaced rather than refurbished.

During the transition to AMI 2.0, Hydro One continues to replace failed AMI 1.0 meters and associated communications network equipment as required while progressively replacing and removing legacy AMI 1.0 infrastructure as AMI 2.0 becomes operational.

3.2.4.1.3.2 REPLACEMENT & REFURBISHMENT

The refurbishment of WRMI components is executed via the corrective maintenance program where it is cost effective. Below is the replacement strategy for Wholesale and Retail Revenue Meters.

3.2.4.1.3.2.1 WHOLESALE REVENUE METERS

Wholesale revenue meters are replaced where they fail, no longer satisfy applicable accuracy or seal requirements, or become technologically obsolete or incompatible with required communications infrastructure.

Historically, WRMIs have generally been managed through corrective maintenance and replacement following failure because individual WRMI component failures typically do not result in a loss of customer load. WRMIs generally include redundant metering capability. Therefore, corrective work is undertaken when required in accordance with applicable IESO Market Rules.

Instrument transformers are normally repaired or replaced based on condition and performance. Proactive fleet replacement is not generally undertaken unless failure experience or other asset information identifies an elevated risk associated with a particular population. Consistent with this approach, the identified ABB instrument transformer models older than 10 years are planned for proactive replacement during the 2028–2032 period based on their observed failure history.

3.2.4.1.3.2.2 RETAIL REVENUE METERS

Hydro One’s replacement strategy for retail revenue meters reflects the stage of the meter population within its lifecycle.

During normal service life, individual failed meters are replaced on a run-to-failure basis. Repair of individual electronic meters is generally not economic given the costs associated with removal, shipping, diagnostic assessment, repair, regulatory reverification and redeployment.

As a meter population approaches end of service life, Hydro One assesses whether continued individual replacement remains appropriate or whether fleet replacement provides a more effective lifecycle strategy. This assessment considers asset age, observed failure trends and root causes, manufacturer service-life information, technological obsolescence, regulatory requirements and the operational costs associated with continued individual replacements.

The AMI 1.0 population has reached this stage of its lifecycle, with approximately half of the retail meter population at or beyond its 15-year service life by year-end 2025. Hydro One is therefore transitioning the population to AMI 2.0 through the approved fleet replacement program. AMI 1.0 meter replacement is expected to be completed by the end of 2029.

Following completion of the AMI 2.0 deployment, the retail metering sustainment strategy will transition to a steady-state approach involving individual replacement of failed AMI 2.0 meters and network equipment, required meter sampling and reverification, and targeted meter conversions or upgrades where required due to obsolescence, customer requirements or regulatory obligations. The AMI 2.0 meters have a vendor-stated expected service life of approximately 20 years.

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Section 3.3 – DSP – BENCHMARKING AND OTHER STUDIES

3.3.1 INTRODUCTION

Benchmarking studies and third-party assessments (the studies) provide Hydro One with insight into the management of its distribution assets and inform the proposed capital expenditure plan. Hydro One engaged several independent third parties to assess key aspects of its distribution system, asset management practices, capital planning assumptions, and long-term investment needs. Overall, the studies indicate that Hydro One's planning and asset management approaches are generally aligned with industry practice, while also highlighting the unique challenges associated with serving a large, predominantly rural service territory, increasing climate-related risks, and the need to prepare the system for continued electrification and customer growth.

Hydro One commissioned the following third-party studies discussed in this section:

- 2026 Hydro One Vegetation Management Study – CN Utility Consulting, Inc. (CNUC)
- Distribution Poles and Substation Transformer Benchmarking Study – Guidehouse Canada Ltd. (Guidehouse) and First Quartile Consulting (First Quartile)
- AMI 2.0 Project Execution Process Review – E Source Companies LLC (E Source)
- Practices of Distribution Loss Reduction Approaches in North America – Electric Power Research Institute (EPRI)
- Vulnerability Assessment and System Hardening (VASH) – Guidehouse Canada Ltd. (Guidehouse)
- Hydro One Networks Inc. Electrification Study 2030-2050 – Environmental Resource Management (ERM)

3.3.2 SUMMARY OF STUDIES AND FINDINGS

The third-party studies commissioned by Hydro One are summarized below. The summaries focus on key findings and contextual observations relevant to Hydro One’s asset management and capital execution practices. The studies are included as attachments to this section.

3.3.2.1 2026 HYDRO ONE VEGETATION MANAGEMENT STUDY – CN UTILITY CONSULTING (CNUC)

3.3.2.1.1 STUDY OVERVIEW

CNUC was retained to carry out an independent review and assessment of Hydro One's distribution utility vegetation management (UVM) program. CNUC prepared a report which is Attachment 1 to this section.

The benchmarking study had the following objectives:

- Review Hydro One's distribution system attributes in relation to peers, other industry survey respondents and Hydro One's past operations; and
- Compare and contrast Hydro One's UVM program with peers, other industry survey respondents and Hydro One's past operations.

CNUC leveraged data from two previous industry-wide surveys in 2019 and 2024 which had 71 and 30 utility respondents, respectively. CNUC developed a survey designed specifically to benchmark 33 selected peers. Utilities were chosen by similarity of size, vegetation management budget and customer base to Hydro One, at least compared to other utilities for which CNUC has basic data. Five Canadian utilities and one US utility responded.

3.3.2.1.2 STUDY FINDINGS

The findings in the CNUC Report are summarized in Table 1.

Table 1 - Key Study Findings

Key Study Findings	Reference
Hydro One's customer density is significantly lower than comparators. Only about half of the average of responding Canadian utilities and 36% of US utilities	Report, p. 22
Largely due to low customer density, Hydro One's cost per customer is roughly 2¾ times greater than the Canadian and US utilities in this study	Report, p. 22
Hydro One's vegetation management budget fell an effective 31% in 2024 from 2020, after inflation adjustment. That has resulted in an 8.3-year cycle, which is unsustainably long. Hydro One should re-establish their budget to adequately maintain a sustainable cycle in line with the 4-5 year industry average but adjusted to vegetative conditions in a particular area.	Report, p. 22
Inadequate investment has not allowed tree crews to reduce the percentage of trees in contact at the time of work and forced the deferral of brush removal and herbicide application. These factors threaten to allow the workload to build and costs to rise in the long-term.	Report, p. 22
Cycle length has influenced two other factors: post work clearances and trees in contact at the time of work. Hydro One's post-work clearances are less than those of other reporting utilities for side and under clearances, the comparatively high percentage of trees in contact at the time of work are a consequence of extended cycle length being too long and insufficient clearances. Modifying either or both based on vegetative conditions addresses this issue. Increasing removal rates will also help Hydro One optimize its cycle length and budget.	Report, p. 22
Hydro One should also implement a brush (sapling) control program. That means a combination of physical removal (mechanically or by hand), and herbicide application wherever it can be applied. Over the past decade, integrated vegetation management (IVM) encourages conversion of the ROW to appropriate low growing plant communities.	Report, p. 22

CNUC's finding that Hydro One has the lowest customer density in terms of customers per circuit-kilometer of line and per square kilometer of service territory highlights the challenges faced by Hydro One due to the unique demands and characteristics of its distribution service territory and density of customers served. The study notes that rural and remote areas are more difficult and expensive to access.

CNUC found that Hydro One's vegetation management budget fell an effective 31% in 2024 from 2020, after inflation adjustment. Hydro One explains in Exhibit E-03-01 that during 2023 and 2024, Hydro One faced market cost pressures, higher demand-driven

work volumes, severe weather, environmental compliance obligations, and evolving security needs. These conditions required the company to make active business decisions about where and when to spend within the overall OM&A funding available. Hydro One prioritized mandatory, safety-critical, customer service, and compliance activities and made a deliberate reprioritization and re-pacing of work over the 2023-2027 rate period to manage pressures within the overall funding envelope. To accommodate these requirements, certain planned maintenance activities, including vegetation management, were deferred or re-paced where risks could be prudently managed in the short term.

The 2028 Distribution OM&A request represents the level of funding required to restore sustainable maintenance levels including vegetation management. The proposed funding will reduce Hydro One's cycle time for clearing vegetation from approximately 8.3 years to 6.6 years, address overgrown brush on its right of ways, and lower unit costs by adopting more efficient work practices. While the funding will not achieve the peer group's reported 4–5-year cycle, it reflects a prudent pacing approach that balances investment needs against rate impacts and moves Hydro One toward the 5-year return-to-site target period within the 2033-2037 rate period.

Details of Hydro One Distribution's vegetation management strategy and program are discussed in DSP Section 3.2, subsection 3.2.3.5 and Exhibit E-03-02, subsection 2.4.

3.3.2.2 DISTRIBUTION POLE AND SUBSTATION TRANSFORMER BENCHMARKING STUDY – GUIDEHOUSE AND FIRST QUARTILE

3.3.2.2.1 STUDY OVERVIEW

Guidehouse Canada Ltd. (Guidehouse) and First Quartile Consulting (First Quartile) conducted a benchmarking study for Hydro One distribution poles and substation transformers. The report provides results and offers insights into Hydro One's distribution pole and substation transformer replacement and refurbishment rates, inspection and maintenance practices relative to a comparison group of 25 U.S. and Canadian utilities. The study was based on First Quartile's annual North American utility benchmarking study. This data was supplemented by a specific survey questionnaire or publicly available

data. Guidehouse's Distribution Poles and Substation Transformers Benchmarking report may be found at Attachment 2 to this section.

3.3.2.2.2 STUDY FINDINGS

The findings in the Guidehouse/First Quartile Report are summarized in Table 2.

Table 2 - Key Study Findings

Key Study Findings	Reference
Hydro One pole replacement and refurbishment practices are primarily driven by condition rather than age, in line with the comparison group; while many pre-1960 poles exceed their nominal service life, they are not automatically replaced unless inspections indicate their condition no longer meets acceptable remaining life criteria.	Report, p. 5
The expected service life of 62 years for Hydro One's wood poles is above the 51-year average for wood poles for the comparison group. Hydro One's wood pole fleet has an average age of 43 years - slightly above the 42-year comparison group average - assuming comparison utilities' poles with unknown installation dates are among the oldest assets in their populations.	Report, p. 5
Hydro One's annual pole replacement rate for exclusively planned replacement activities in 2024 was 0.3 percent, which was marginally below the median of the comparison group. The annual rate for planned and expected replacements over the next 5 years (2025-2029) for Hydro One is projected to be 0.2 percent, which is lower than the comparison group median of 0.78 percent.	Report, p. 5
Hydro One's service territory covers more surface area than the average comparator and includes a significant proportion of rural and remote locations. The average number of customers served by Hydro One distribution circuits per kilometer is among the lowest in the comparison group. The largest share of Hydro One poles were installed pre-1960, with additional concentrations from the 1960s–1970s.	Report, p. 5
Hydro One's six-year visual inspection interval is more frequent than the comparison group's 10-year average but is consistent with Ontario Energy Board (OEB) inspection requirements; its pole testing interval of 15 years is longer than the 10-year average for the comparison group.	Report, p. 5
Hydro One's distribution substations typically serve rural areas with low load density versus the comparison group. The number of transformers per distribution circuit kilometer is among the lowest in the comparison group.	Report, p. 6

Key Study Findings	Reference
Most Hydro One substations are equipped with one transformer with low side voltages predominantly rated 9kV and below. Other utilities in the comparison group include up to two or four transformers per station with higher low side voltages, mostly 15kV (e.g., 12.47kV)	Report, p. 6
Hydro One's substation transformers operate at an average peak loading of about 75 percent (as a percentage of nameplate capacity) and is the highest among the reporting utilities whereas others in the comparison group typically have an average loading of below 75 percent, which enables contingency support and tie transfer schemes.	Report, p. 6
Hydro One employs a range of approaches for planned substation equipment inspections, with time-based methods as the primary focus and condition-based approaches following closely behind. Overall, Hydro One's practices are broadly aligned with those observed across the comparison group.	Report, p. 6
The average age of Hydro One's distribution transformers is 42 years, which is above the comparison group average of 35 years. Hydro One's distribution transformers show a relatively even age distribution across the past six decades, with installations peaking in the 1970s.	Report, p. 6
Hydro One's annual distribution transformer replacement rate was 0.04% (reflecting a single project) between 2023-2024, increasing to a projected 0.32% for 2025–2029, below the comparison group median of 0.88%. For the purposes of this study, replacement activity is limited to condition-based needs and excludes load growth expansion.	Report, p. 6

The Guidehouse/First Quartile study provides a reasonable benchmarking of Hydro One's Distribution asset management practices in respect of distribution poles and distribution substation transformers. The study used a comparison group of North American utilities. The study concludes that Hydro One's asset management practices for distribution poles and substation transformers are generally aligned with industry peers in terms of using condition-based decision-making, inspection practices, and maintenance approaches. However, the study highlights that Hydro One has:

- Older-than-average pole and transformer fleets
- Lower planned replacement rates than comparator utilities
- A significantly larger, more rural, and geographically dispersed service territory than peers
- Higher utilization of substation transformers than other reporting utilities

The report notes that Hydro One's replacement decisions are driven primarily by asset condition rather than age, which is consistent with leading utility practices.

The study also highlights the unique characteristics of Hydro One's service territory, including its extensive geographic footprint, low customer density, and significant proportion of rural and remote infrastructure. These factors differentiate Hydro One from many comparator utilities and influence both asset management strategies and investment priorities.

The findings demonstrate that Hydro One maintains a rigorous inspection and assessment program, including a six-year visual pole inspection cycle that exceeds the frequency observed across much of the comparison group and aligns with OEB requirements. The study also notes that the expected service life of Hydro One's wood poles exceeds the comparison group average, supporting the effectiveness of the company's condition-based asset management approach.

Asset replacement decisions are informed by ongoing inspection, testing, loading, and condition assessment data. This approach seeks to balance reliability, safety, and customer value while ensuring that investments are targeted at assets presenting the greatest risk.

While Hydro One’s annual distribution substation transformer replacement rate is projected to average 0.32% during 2025-2029, with the proposed investment it is expected to increase to 1.4% over the 2028-2032 rate period.

While Hydro One’s annual distribution pole replacement rate is projected to average 0.2% during 2025-2029, with proposed investment over 2028-2032 it is planned to increase to about 1.1% per year.

Details of Hydro One poles and distribution transformers are found in DSP Section 3.2 Asset Information and Lifecycle Strategies. DSP Section 3.11, D-SR-04, Distribution

Station Renewal and DSP Section 3.11, D-SR-07, Pole Sustainment Program provide details of Hydro One's investments in the 2028-2032 planning period.

3.3.2.3 AMI 2.0 PROJECT EXECUTION PROCESS REVIEW – E SOURCE

3.3.2.3.1 STUDY OVERVIEW

Hydro One Distribution is replacing its original Advanced Metering Infrastructure (AMI) system with a next-generation AMI 2.0 solution that includes deployment of meters, communications infrastructure, and supporting enterprise systems. Large-scale AMI replacement programs are complex, multi-year initiatives.

Hydro One engaged E Source Companies LLC (E Source) to conduct an independent review of the AMI 2.0 project execution process to evaluate whether execution to date is reasonable and justifiable relative to the established Project Baseline, similar industry programs, and the organization's evolving operational and technical requirements.

The review was conducted through a structured approach that included document review, stakeholder interviews, and a market scan of other North American utility AMI deployments. The review included assessment of project governance, execution management, budget and schedule performance, deployment strategy, systems integration activities, vendor oversight, and key execution challenges encountered throughout the program lifecycle. The E Source AMI 2.0 Project Execution Process Review report may be found at Attachment 3 to this section.

3.3.2.3.2 STUDY FINDINGS

The findings in the E Source Report are summarized in Table 3.

Table 3 - Key Study Findings

Key Study Findings	Reference
The AMI 2.0 Project Baseline scope, budget and schedule align with Hydro One's EB-2021-0110 filings and associated regulatory updates, including inflation adjustments incorporated throughout the program lifecycle.	Report, pp. 15-17
Hydro One's governance and project management framework is appropriately structured for a program of this scale and complexity based on the review of documents compared to the Project Management Checklist.	Report, p. 19
Several execution challenges had impacts across multiple project dimensions (scope, budget and schedule) simultaneously.	Report, p.19
Hydro One identified, escalated, and responded to these challenges through a structured project governance and various mitigation strategies, including phased contracting, parallel execution of workstreams, deployment planning adjustments, automation, defect prioritization, and targeted resource management activities.	Report, p. 5
The market scan of eight North American utilities further demonstrated that many utilities in the market scan group experienced similar challenges related to systems integration, meter deployment logistics, regulatory requirements, workforce constraints, evolving AMI functionality expectations, and maturity of the solution. As such, the execution challenges encountered by Hydro One are not unique within the context of next-generation AMI modernization programs.	Report, p.29
Hydro One's forecasted capital cost per meter is approximately $532.9. The average of the market scan utilities is approximately $498.7 based on a market scan of eight utility AMI programs. Hydro One's forecasted capital cost performance remains directionally consistent with the market scan group of AMI programs when differences in program scope, operating conditions, and implementation complexity are considered.	Report p. 30
Hydro One's forecasted 6-year deployment timeline remains generally aligned with the market scan group of utility programs, particularly when considering the scale of deployment, lower meter density, coexistence of legacy and next-generation AMI environments, and Ontario-specific implementation requirements.	Report, p. 31
Hydro One's AMI 2.0 project execution, including its governance structure, management approach, scope evolution, budget adjustments, and schedule management, remains reasonable when evaluated against similar industry programs and the complexity inherent in large-scale AMI modernization initiatives.	Report, p.33

E Source assessed Hydro One's deployment progress and execution approach in the context of comparable industry programs.

E Source found that, notwithstanding execution challenges encountered during implementation, Hydro One's forecasted deployment timeline remains generally aligned with similar AMI 2.0 programs. The review further indicates that the execution challenges experienced by Hydro One were not unique but were also observed among utilities included in the market scan group. In addition, E Source found that Hydro One has maintained overall schedule control through phased execution strategies and the concurrent execution of key activities. While the forecasted completion date is approximately one year later than the original baseline, E Source considers the updated program timeline to remain reasonable considering the challenges encountered.

Details of the Advanced Metering Infrastructure 2.0 investment are contained in DSP Section 3.11, D-SR-12.

3.3.2.4 PRACTICES OF DISTRIBUTION LOSS REDUCTION APPROACHES IN NORTH AMERICA – ELECTRIC POWER RESEARCH INSTITUTE (EPRI)

3.3.2.4.1 STUDY OVERVIEW

In its report, EPRI provided a survey of distribution loss management practices from 22 North American utilities. Eight of the most prominent loss management methods are discussed: raising medium voltage (MV) levels (e.g. conversion from 4kV to 13kV, etc.), volt var (power factor) optimization, conservation voltage reduction, reconductoring (increasing conductor sizes), feeder topology reconfiguration (seasonal feeder adjustments based on forecast loading), splitting ancillary / low voltage (LV) networks, maintaining proper load balancing between phases; and installing more efficient distribution MV/LV transformers.

In addition, EPRI conducted a series of detailed power flow simulations using Hydro One sample feeders representing multiple voltage classes and a range of initial operating conditions. Each loss reduction management strategy was evaluated using the Hydro One sample and classified as having a high (>2%), medium (0.5-2%), or low (<0.5%) benefit based on its estimated reduction in total peak distribution technical losses. The EPRI

Practices of Distribution Loss Reduction Approaches in North America report may be found at Attachment 4 to this section.

3.3.2.4.2 STUDY FINDINGS

The findings in the EPRI Report are summarized in Table 4.

Table 4 - Key Study Findings

Key Study Findings	Reference
The key learnings from the utility survey include: • Loss Reduction is seldom a primary driver for investment; • Loss Reduction strategies are not always apparent and are often embedded into planning criteria or distribution feeder design standards; and • Loss Reduction is more often a desirable incidental benefit associated with other primary objectives such as reliability or load growth.	Report, p.12
The results of the power flow investigation indicate these projects have the following loss reduction benefit classifications • raising MV voltage: high benefit • volt var optimization projects: low benefit • conservation voltage reduction projects: low benefit • reconductoring: low benefit • feeder topology reconfiguration: low benefit • splitting LV networks: low benefit • maintaining proper load balancing between phases: medium benefit • installing more efficient distribution transformers: low benefit	Report, pp. 13-23
Based on EPRI's experience and research, line losses are almost never the primary driver for investments. Rather, loss reduction is an ancillary benefit. In general, these investments are made for a variety of other purposes, notably managing capacity or thermal limits and/or regulating delivered voltage.	Report, p.24

As discussed in DSP Section 3.6, Subsection 3.6.7, Hydro One Distribution has implemented a number of practices through which distribution loss reduction is achieved as a secondary benefit and will continue to realize loss-reduction ancillary benefits through investments undertaken to address broader system needs such as Distribution Station

Renewal (DSP Section 3.11, D-SR-04), Voltage Consolidation (DSP Section 3.11, D-SR-17) and System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01).

3.3.2.5 VULNERABILITY ASSESSMENT AND SYSTEM HARDENING – GUIDEHOUSE

3.3.2.5.1 STUDY OVERVIEW

The OEB's Vulnerability Assessment and System Hardening (VASH) Framework [1] requires that all Ontario electricity distributors include a VASH analysis in rebasing applications for 2028 rates.

Hydro One engaged Guidehouse to prepare a VASH analysis as an input to the DSP. Hydro One tasked Guidehouse to complete a vulnerability assessment identifying the assets and feeders in its service territory most vulnerable to the evolving severity of key climate perils. Guidehouse then conducted a pre-assessment to determine whether technically and economically feasible system hardening investments exist and, finally, a benefit cost analysis (BCA).

Guidehouse included five of Hydro One's resiliency measures (RM) in its VASH analysis:

- **Clustered Hardening** – The replacement of poor condition poles on a targeted feeder. Replacement poles are, where possible, a higher class (more resilient) pole
- **Covered Conductor** – Segments of approximately 3 km of targeted feeders' conductor are replaced with covered conductor to reduce faults from tree contact
- **Selective Undergrounding –** Segments of between 1 and 3 km targeted feeders' overhead conductor (and a corresponding number of poles) are removed and lines are relocated underground
- **Sectionalization** – Switches, reclosers, and ties to adjacent feeders are applied to the targeted feeders

[1] Ontario Energy Board, Vulnerability Assessment and System Hardening Report; EB-2024-0199 – Vulnerability Assessment and System Hardening (VASH) Project, October 2025
Available at: https://engagewithus.oeb.ca/vulnerability-assessment-system-hardening

- **Voltage Conversion & Sectionalization** – Sectionalization, including new ties, is applied following a voltage conversion on the targeted feeder.

The Guidehouse vulnerability assessment considered the two climate perils for which severity return intervals have been provided by the OEB in its Toolkit: ice accretion from freezing rain and wind speed. Consultation with Hydro One confirmed that these two perils were the primary weather-based drivers of *force majeure* (resiliency) outages. The analysis focused on two asset classes - poles and conductors, further broken into asset subclasses. A failure threshold for each peril and each asset subclass was estimated based on published material and informed by Hydro One expertise and experience. The threshold exceedance probabilities were derived from the OEB toolkit including changes in expected severity of climate perils projected by Environment and Climate Change Canada (ECCC) through the year 2100 for 230 locations. To simplify the analysis, Guidehouse categorized data provided by Hydro One for 3,200 feeders into 327 feeder archetypes based on region, assigned climate location, and type (F-class or M-class). The archetype is defined by the average asset count of all included feeders and therefore each archetype has a common probability of failure. The archetypes are ranked by relative vulnerability.

In the pre-assessment phase, Guidehouse identified feeders that could be targeted as part of the BCA. Guidehouse developed a ranking of individual feeder level vulnerability by applying historical outage data and the number of customers served to each feeder's archetype vulnerability score. This input was combined with feeder candidates that were suitable for a specific RM to create 27 "average program feeders" and to simplify the potential quantification of RM benefits.

To conduct the BCA, Guidehouse used the vulnerability assessment, five years of Hydro One's force majeure outage data, and the Lawrence Berkeley National Laboratory's Interruption Cost Estimate (ICE) 2.0 calculator to evaluate the Value of Lost Load (VoLL) for each resiliency measure. The Guidehouse Vulnerability Assessment and System Hardening report may be found at Attachment 5 to this section.

3.3.2.5.2 STUDY FINDINGS

The findings in the Guidehouse Report are summarized in Table 5.

Table 5 - Key Study Findings

Key Study Findings	Reference
The vulnerability assessment identified that from a forward-looking climate perspective, Hydro One's most vulnerable assets are in its East region and, to a lesser extent, in the areas of the North and Central region nearest to the East region.	Report, p. 73
The estimated set of BCAs demonstrates that the implementation of resilience measures to mitigate against these vulnerabilities can deliver value to customers, even when consideration of benefits is limited mostly to resilience benefits. This value has been demonstrated to increase as the focus of the resilience measure is more tightly targeted to Hydro One's most vulnerable assets.	Report, p. 73
Some Benefit Cost Ratios (BCR) reach 1.0 based principally only on resilience benefits is a noteworthy outcome given the conservative modeling assumptions and inputs adopted by Guidehouse when addressing key uncertainties. In addition to accounting only for some of the customer benefits (with normal reliability notably excluded), the analysis does not assume any growth in customer numbers over time and uses a unit value of lost load derived from the ICE calculator, which may understate the value of lost load in *force majeure* events.	Report, p. 73
A targeted approach to asset and customer data collection as part of a resilience investment program will help Hydro One to identify projects most likely to deliver significant net customer benefits. This would include: • **Customer Data Collection.** Targeted collection of customer information associated with promising feeders or feeder segments could include: ○ *Feeder/Customer-Specific VoLL.*More precisely quantifying the value of lost load for specific customer segments or even individual customers will allow for a more accurate targeting of resilience measures to where they will deliver the most benefit. For example, quantifying VoLL for critical loads, such as hospitals or water treatment facilities and for vulnerable customers (such as those in remote communities or in large multi-family buildings) may help to better target cost-effective resilience investments. ○ *Customer Growth.* Appropriately considering population growth projections, cross-referenced with regional planning assumptions for specific feeders (or feeder segments) of interest will help to more accurately quantify future resilience benefits in locations expected to experience significant load growth in the future.	Report, p. 73-74

Key Study Findings	Reference
• **Asset Engineering Data Collection and Analysis.** A focused assessment of specific assets on feeders or feeder segments by engineers and planners could more precisely identify: ○ *Addressable Vulnerabilities.* Considering vegetation or the surrounding conditions of a specific feeder segment as well as its location relative to the station and customers could allow engineers to more precisely identify assets most suitable for undergrounding. Such work would also allow planners to better quantify the value of this RM. ○ *Cost Efficiencies and Network Effects.* Evaluating costs on a more specific location-by-location basis can help identify opportunities to bundle or sequence infrastructure improvements efficiently across projects and bring down costs. • **Comprehensive Assessment of Benefits.** A focus on a single primary value stream (resilience) is appropriate for a higher-level analysis like the VASH study, but site-specific assessments conducted as part of Hydro One's standard program implementation process should consider benefits comprehensively. Including consideration of reliability and other quantitative and qualitative benefits to customers will help to identify those opportunities for resilience measures that most drive value to Hydro One customers.	

Hydro One's discussion of vulnerability assessment and system hardening investments is included in DSP Section 3.6, subsection 3.6.6.

3.3.2.6 ELECTRIFICATION STUDY 2030-2050 – ENVIRONMENTAL RESOURCE MANAGEMENT (ERM)

3.3.2.6.1 STUDY OVERVIEW

In satisfaction of an EB-2021-0110 settlement commitment, Hydro One commissioned ERM to provide an independent study to understand how electrification could shape energy use and peak load on its distribution network between 2030 and 2050, and to identify how cost-effective non-wires solutions, such as energy efficiency (EE), behind-the-meter distributed energy resources (DER), and demand-side flexibility (DSF), can mitigate reinforcement needs.

ERM utilized Hydro One station level data, the near-term pipeline of large I&C customers incremental demand and available information on population growth expectations, electricity consumption technologies, trends and policies to develop outlooks of future peak load growth under three core scenarios: Business as Usual, a baseline scenario where the economy still depends largely on fossil fuels; System Transition, which sees widespread electrification with moderate energy efficiency improvements and distributed energy resources rollout; and Net Zero 2050 (NZ 2050), where Net Zero goals are met by 2050, and entails significant electrification of all key sectors like heating and transport. Two worst-case sensitivities for the System Transition and Net Zero 2050 scenarios were also defined to reflect a similar uptake of low-carbon technologies like EVs and heat pumps, but assume minimal improvements in energy efficiency, lower distributed energy resources penetration, and limited incremental demand-side-response. The worst-case sensitivities see the same uptake of electric technologies as their respective electrification pathways, but the same improvements to energy efficiency and solar and storage rollout as the Business-as-Usual scenario, and no increase in demand-side flexibility.

The scenarios are not assigned probabilities; each is used to examine how the different assumptions would impact the peak load projections. These scenarios are to be distinguished from load forecasts, which are used for planning, and based on detailed market analysis and specific customer information. Single large demand sites like data centers were excluded from the study because they lead to a large increase in demand that cannot be predicted or modelled accurately without site specific knowledge, which was unavailable for the study.

ERM shared preliminary results with key stakeholders from the previous rate application on November 25, 2025, and incorporated feedback into the final report. The ERM Electrification Scenarios 2030-2050 report may be found at Attachment 6 to this section and information on the stakeholder session may be found at Attachment 6.1.

3.3.2.6.2 STUDY FINDINGS

The findings in the ERM Report are summarized in Table 6.

Table 6 - Key Study Findings

Key Study Findings	Reference
Peak demand is expected to rise over the coming decades across all scenarios, driven primarily by the electrification of heat and transport, as well as by a near-term pipeline of large I&C customer. The Business-as-Usual scenario presents the slowest load growth, reflecting limited uptake of electric technologies. In contrast, both System Transition and Net Zero 2050 show substantially higher peaks, consistent with widespread adoption of heat pumps and electric vehicles.	Report, p. 9
Notably, the Net Zero 2050 – Worst-Case and System Transition – Worst-Case sensitivities reveal the significance of energy efficiency, behind-the-meter solar and storage, and demand-side flexibility to mitigate the increase in peak load.	Report, p. 9
A key finding is that the Hydro One network is expected to transition from a summer-peaking to a winter-peaking system within the next decade as heating electrifies. Winter evening peaks become the dominant system constraint, while summer peaks shift later into the evening as rooftop solar reduces early evening demand and electric vehicle charging increases evening and overnight consumption.	Report, p. 11
The results underline the importance of integrating energy efficiency programs, demand-side flexibility, and distributed energy resources into long-term network operations. These insights can support Hydro One in targeting cost-effective non-wires solutions and prioritising network investments, while detailed cost-effectiveness assessments are undertaken separately using Ontario's established regulatory frameworks on a project-by-project basis.	Report, p. 11

The ERM Study and its implications are discussed in detail in DSP Section 3.6, subsection 3.6.3. The study highlights the impact of electrification with lower energy efficiency and other demand reduction drivers resulting in a substantially higher system peak by 2050. Hydro One has initiated several strategic investments and Non-Wires Solutions aimed at reducing local and system peaks to defer or avoid the expansion of existing infrastructure as the demand for electricity grows.

3.3.3 ATTACHMENTS: STUDIES

Table 7 below outlines the attachments to this Exhibit.

Table 7 - Attachments

Attachment	Report
1	Hydro One Vegetation Management Study – CNUC
2	Distribution Poles and Substation Transformer Benchmarking Study – Guidehouse and First Quartile
3	AMI 2.0 Project Execution Process Review – E Source
4	Practices of Distribution Loss Reduction Approaches in North America – EPRI
5	Vulnerability Assessment and System Hardening (VASH) Study – Guidehouse
5.1	VASH Assessment Toolkit
6	Hydro One Networks Inc. Electrification Scenarios 2030-2050 – ERM
6.1	Electrification Scenarios Stakeholder Session

``

CNUC

2026 Hydro One Vegetation Management Study

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September 23 2026

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Executive Summary

CN Utility Consulting, Inc. (CNUC) completed an independent benchmark review of Hydro One Networks Inc.'s (Hydro One) distribution utility vegetation management (UVM) program. The assessment updates CNUC's 2009, 2016, and 2020 Hydro One studies and compares Hydro One's current program with its historical performance, responding Canadian utilities, selected US utilities, and broader North American industry survey results.

Hydro One operates in a challenging UVM environment. Its distribution system is predominantly rural and remote, has substantial forest exposure, includes a large right-of-way (ROW) footprint, and serves a comparatively low-density customer base. These conditions require Hydro One to manage more line kilometers, greater vegetation exposure, and more travel time per customer than most utilities included in the comparison groups.

The study addressed two primary objectives:

1. Review Hydro One's distribution system attributes in relation to peers, other industry survey respondents and Hydro One's past operations.

2. Compare and contrast Hydro One's UVM program with peers, other industry survey respondents and Hydro One's past operations.

The central finding is that Hydro One's 2017 strategy change produced meaningful reliability benefits, but the program is now showing signs of stress. Since 2020, reduced real funding has contributed to a longer work interval, lower removal rates, deferred brushing, limited herbicide use, and continued high levels of trees in contact at the time of work. These trends increase the risk that deferred workload, future cost, and vegetation-caused reliability impacts will grow if program scope is not restored.

SYSTEM ATTRIBUTES

Hydro One's service territory is materially different from the comparison utilities. Only 2% of its system is urban or suburban, and its distribution ROW footprint is larger than most respondents. Hydro One serves approximately 14.4 customers per kilometer, roughly half the density of responding Canadian utilities and about 36% of the US utility average. This low customer density is a critical driver of UVM cost because Hydro One must maintain more line kilometers and manage more vegetation exposure for each customer served.

PROGRAM ATTRIBUTES

Several program indicators suggest that Hydro One is operating below the work scope needed for long-term sustainability. The 2024 removal rate declined to 26% from 39% in 2020; reported post-work clearances are lower than participating Canadian utilities; herbicide treatment was reported on only 1% of the system despite broad potential applicability; and the estimated work interval lengthened to 8.3 years, compared with approximately 4.8 years for Canadian utilities and 4.5 years for US utilities. These indicators show that Hydro One has emphasized near-term reliability risk while deferring some activities essential to future workload control.

- Hydro One's 2024 removal rate of 26% was down from its 39% rate of 2020 (Figure 8).
- Hydro One's clearances are statistically lower than the participating Canadian utilities and CNUC's 2024 survey (Figure 9).
- Hydro One only treated 1% of their system with herbicide, compared to 16% by Canadian utilities (Figure 10).

- The 2024, 8.3-year work interval[1] (cycle length) was statistically longer than the cycle of participating Canadian (4.8 years) and US utilities (4.5 years). Moreover, Hydro One's 2024 cycle length is substantially longer than their 2020, 4.1-year cycle (Figure 11).
- Hydro One's 31% of trees in contact with power lines at the time of work is not substantially different than their 30% in 2020. However, it is significantly more than the average of utilities that responded to CNUC's 2024 survey (Figure 12).
- The 11% of reactive work is significantly less than the responding Canadian utilities' 20.2%, but more than double the 4.2% of participating US utilities (Figure 13).

OPERATIONAL OUTCOMES

Operational outcomes show both progress and vulnerability. Vegetation-related system average interruption duration index (SAIDI) improved from Hydro One's 2017 peak and averaged 2.5 hours from 2021 through 2024, but it remains higher than the Canadian utility comparison group and the broader recent industry survey average. At the same time, the 31% inflation-adjusted budget reduction from 2020 to 2024 has lengthened the maintenance interval, reduced removals, limited brush and herbicide work, and left a relatively high percentage of trees in contact at the time of work.

- Through implementation of the optimum cycle protocol (OCP) in 2017, Hydro One had reduced its maintenance interval from 9.5 years in 2016 to a projected first cycle of 4.1 years in 2020. This interval has now risen back to an estimated 8.3 years according to the 2024 survey response. This estimated interval is longer than the peer and industry responses which presented average cycle lengths between 4 and 5 years across all groups.
- Hydro One reduced their cost per right-of-way kilometer by more than half from $12,850 in 2016 to $5,480 in 2020. The 2023-2024 average cost of $6,616 is only a small rise (in line with inflation) in that per kilometer value (Figure 16). Hydro One reports achieving this consistent cost per kilometer value as a byproduct of shifting priorities to more imminent reliability management, such as pruning and removing fewer trees and limiting brush removal throughout the system. That strategy minimized short term reliability impact but has left a greater workload for the future. Pruning, brushing, and herbicide activities must resume in full to manage future reliability and costs.
- Hydro One's 2020 vegetation-caused average interruption duration index (SAIDI) of 2.5 hours from 2021 to 2024 was significantly higher than the 1.0 hours of Canadian utilities (Figure 20). However, it is 30% better than Hydro One's peak of 3.6 hours in 2017. The Clear Path report predicted a 20% reduction in this value with the implementation of OCP which is reflected in the previous four-year average (2021-2024) against the 2017 recorded high.

CNUC recommends that Hydro One re-establish funding and work scope sufficient to support a sustainable, condition-based maintenance interval; increase removals where risk warrants; restore brushing and compatible herbicide application as part of an integrated vegetation management approach; and use periodic vegetation assessment to guide scheduling, budgeting, and workload forecasting. These actions would help Hydro One preserve the reliability gains achieved since 2017 while reducing the likelihood of deferred workload, rising future costs, and increased vegetation-caused outages.

[1] A work interval is the time between methods used to control vegetation on a site.

1 Introduction

1.1 STUDY PURPOSE

CNUC was retained to carry out an independent review and assessment of Hydro One's distribution utility vegetation management (UVM) program. This review was conducted by studying and performing comparisons of relevant metrics with the aim to provide insights into how Hydro One'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, 2016 and 2020, CNUC completed benchmarking projects to determine the relative efficacy of Hydro One's UVM program. As a basis for these projects, CNUC invited a relevant group of UVM benchmarking members to participate in surveys. This study is the latest iteration of that series.

1.2 STUDY TEAM

CNUC was selected as an independent third-party consulting team to execute Hydro One's UVM benchmarking study. In addition to benchmarking experience with Hydro One specifically, CNUC has expertise in both UVM and benchmarking that is unique in North America.

1.3 OBJECTIVES

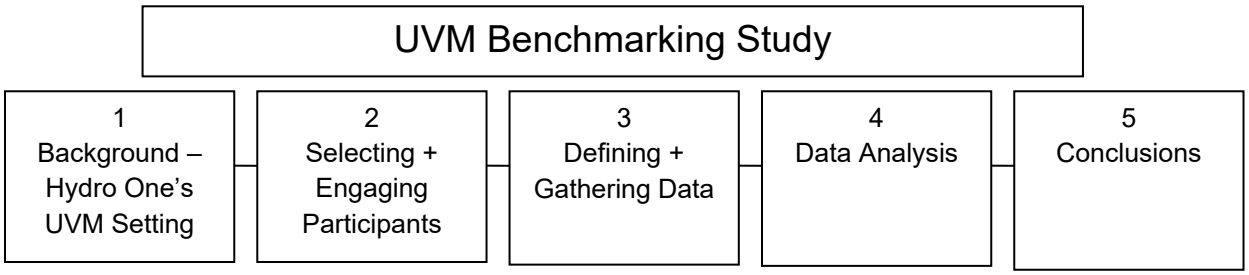
CNUC had two objectives in this study:

- Review Hydro One's distribution system attributes in relation to Canadian and US utilities that responded to a survey CNUC prepared for this study. CNUC also leveraged responses from past surveys to provide information in some cases.
- Compare and contrast Hydro One's UVM program with peers, other industry survey respondents, and Hydro One's past operations.

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.



2.2 Hydro One's UVM Setting

This section of the report summarizes operating conditions and practices to provide context for Hydro One's vegetation management program.

Hydro One serves the majority of Ontario (Figure 1). Hydro One Distribution is one of roughly 60 local distribution companies (LDCs) that serve the province (Electricity Distributors Association, 2026).

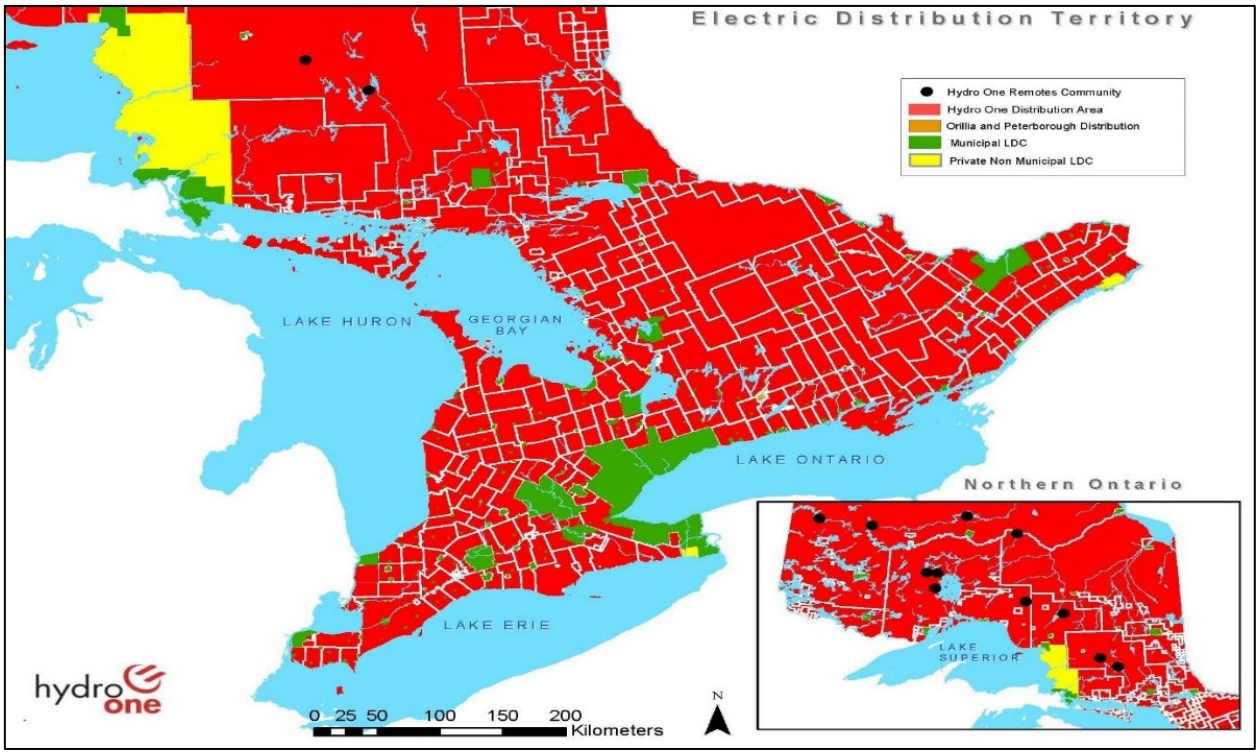


Figure 1. Hydro One Service Territory

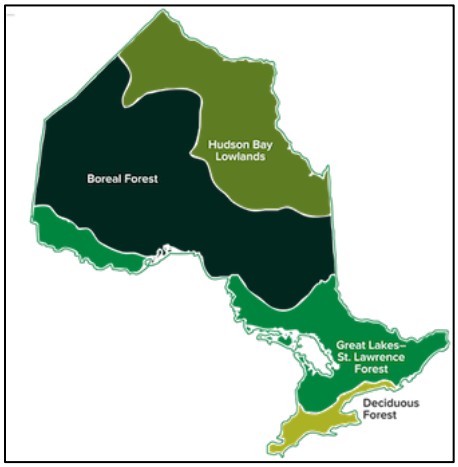


Figure 2. Forest regions in Ontario.

The majority of Ontario has a rural and remote character. It is heavily forested, with approximately 71 million hectares of forest. Its forests can be split into four distinctive regions (Figure 2) (Ontario Environment and Energy, 2021): 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.

Each of the four forest regions is distinct from the others (Figure 3) (Ontario Environment and Energy, 2021). 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.

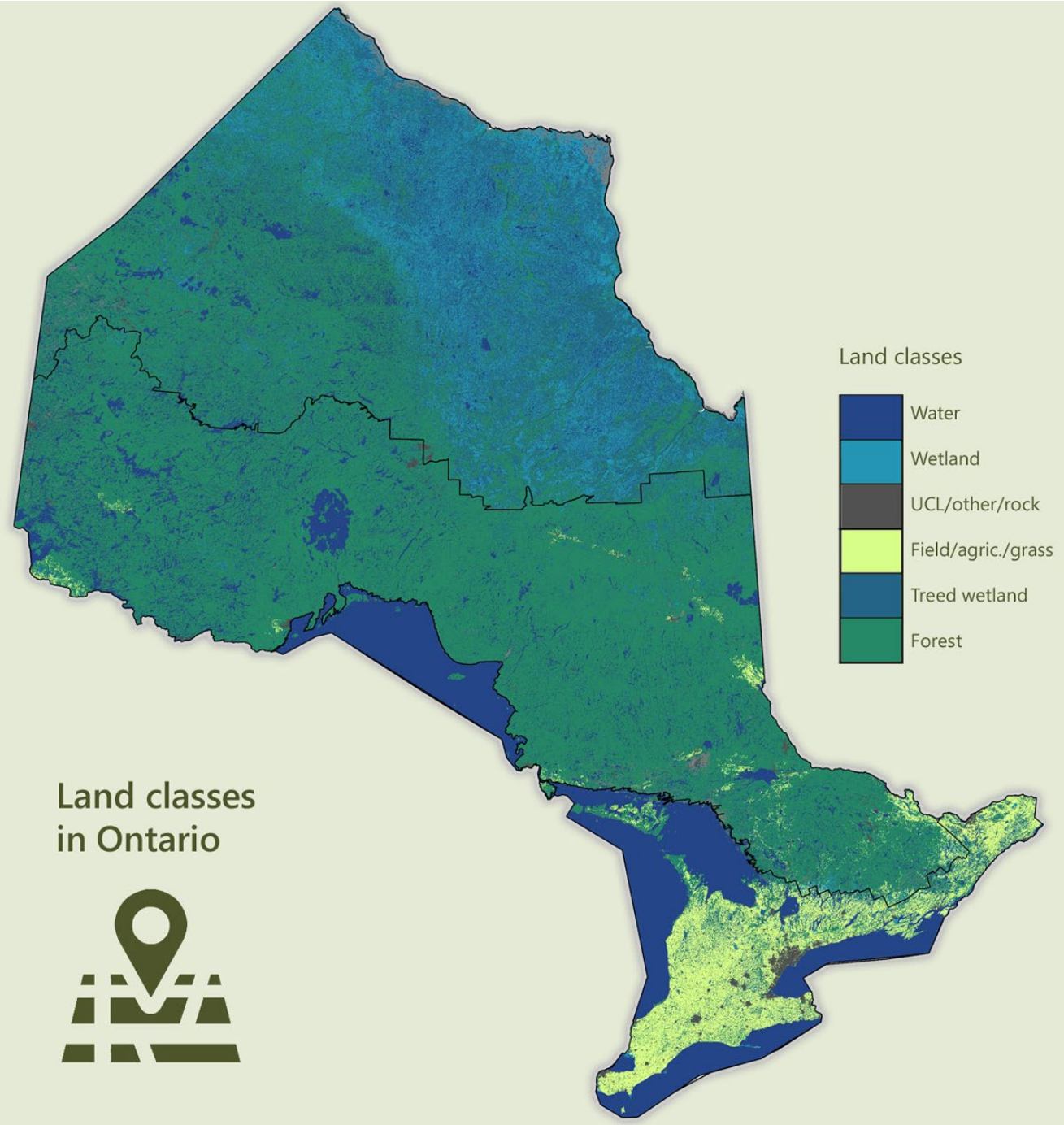


Figure 3. Landcover of Ontario (Ontario Environment and Energy, 2021)

2.3 2017 CHANGE IN UVM STRATEGY

In the late twenty-teens, Hydro One implemented a shift from a corridor-based approach (clearing vegetation from power lines from within the right-of-way) to one driven by high-risk trees and tree-powerline conflicts (defect-driven). The approach began with a targeted three-year maintenance cycle, accompanied by robust high-risk tree removal and quality control programs to reduce vegetation defects, improve reliability, and lower long-term cost. These changes were implemented by Hydro One starting in the fourth quarter of 2017 with execution commencing in earnest in 2018. This represented a significant philosophical change in vegetation management operations for Hydro One, directing resources to areas of greater need.

2.4 SELECTING + ENGAGING PEER UTILITIES

For the current study, CNUC used a combination of surveys to obtain information. First, CNUC has access to the UVM benchmark surveys conducted for Hydro One in 2009, 2016, and 2020. This information was useful for context and analysis of Hydro One over time. In some cases, CNUC used Hydro One's peer group data from our 2016 and 2020 studies where it could provide insight or where insufficient data was available from more recent and targeted surveys. These groups are noted as Peers 2016 and Peers 2020 throughout the report.

For the most recent iteration, CNUC identified 33 utilities to serve as peers. The following considerations entered peer selection:

- Geographic proximity to Hydro One
- Climatic similarity
- Estimated tree density and species characteristics
- Number of customers
- Kilometers of overhead distribution lines

CNUC also invited Canadian utilities to participate. CNUC considered other Canadian utilities to be beneficial because they have comparable regulatory oversight and other similarities to Hydro One. These include large service territories with lower customer density than US utilities and uniquely Canadian focus areas such as working with First Nations on treaty lands.

CNUC developed a survey designed specifically to benchmark the 33 selected peers. Utilities were chosen by similarity of size, vegetation management budget and customer base to Hydro One, at least compared to other utilities for which CNUC has basic data. However, only 5 Canadian utilities and 1 US utility responded (Table 1).

To increase the number of comparative utilities, CNUC utilized data for 5 US utilities from the identified peer list that responded to the AR 2024 CNUC-UW Stevens Point industry survey (Blair et al., 2026). That survey collected data for the period of 2021-2023. In addition, the single American Utility respondent to the 2025 survey was added to the US group. That created distinct Canadian and US respondent groups (Table 2). This solution maximizes the number of utilities with available data. However, not all Hydro One specific data was captured in the AR 2024 survey. Additionally, not all participating Canadian utilities supplied answers to the full survey. As a result, the number of responses to some questions differs from others, but all responses provided for each question are included in analysis. Hydro One data was collected in 2025, from the 2024 and prior years' statistics. The number of utilities responding to a specific question are presented in figures.

Table 1. *Utilities used in this Benchmark. Evergy represents the only US utility to respond to this specific benchmarking survey. Other US utility data was sourced from AR 2024 CNUC-UW Stevens Point industry survey results*

Canadian Utilities		
BC Hydro	**Fortis Alberta**	**Manitoba Hydro**
Nova Scotia Power	**Toronto Hydro Electric System Ltd.**	
US Utilities		
Consumers Energy	Commonwealth Edison	Evergy
First Energy	Northwestern Energy	Unitil

Table 2. *Data sets used in this report*

Abbr.	Survey	Years	Total participants
Hydro One 2016	**CNUC 2016 benchmark survey – Hydro One response**	**2011-2015**	**1**
Peer 2016	**CNUC 2016 benchmark survey**	**2011-2015**	**27**
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**
Hydro One 2020	**Hydro One OCP actuals**	**2018-2020**	**1**
AR 2024	**CNUC-UWSP 2024 Industry Survey – all respondent group response**	**2021-2023**	**30**
US Utilities	**Peer group from 2024 CNUC-UWSP Industry Survey + First Energy**	**2021-2023**	**6**
Canadian Utilities	**CNUC 2024 peer group supplemental survey response**	**2021-2024**	**5**
Hydro One 2024	**CNUC Benchmark Survey – Hydro One response**	**2021-2024**	**1**

2.5 DEFINING AND GATHERING DATA

In its past projects, CNUC developed surveys to benchmark Hydro One against its peer group. In this study, CNUC had recently completed another of its routine industry surveys, which covered some of the same scope as previous Hydro One benchmarking surveys. Further, in the survey developed specifically for the Canadian utilities, CNUC conducted surveys related to the following general UVM program areas:

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

CNUC also conducted background interviews with Hydro One staff.

2.6 DATA ANALYSIS

Data collected by CNUC was compiled and analyzed. CNUC used metric units and Canadian dollars (CAD), converting from Imperial units and United States dollars (USD) where appropriate. CNUC applied the annual average change in the Canadian consumer price index of 3.66% from 2020-2024 (Canada Inflation Calculator, 2026) (Bank of Canada, 2026) and an average 2020-2024 USD to CAD exchange rate of $1.32. Currency conversions facilitated fair comparisons among utilities operating in Canada and the United States (US).

Within this report, CNUC defines mean as the arithmetic mean, the sum of values divided by the total responses. The standard error of the mean (SE) was used to estimate how far the sample mean is likely to be from the population mean. For example, the current reported length of the intended UVM cycle among responding Canadian utilities was 4.8 years, with a standard error of 0.1 years. So, the expected population mean is between 4.7 and 4.9 years (Figure 11). Within the report, all error bars in a figure are SE bars and are presented in black. When comparing two groups, CNUC looks 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, examine the SE. When SE bars overlap, the difference is not statistically significant. In this report CNUC uses the term “statistically different” to mean that the SE of the comparison group does not overlap the mean with the Hydro One data.

3.0 Results and Discussion

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

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

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

3.1 SYSTEM ATTRIBUTES

CNUC benchmarked Hydro One's system attributes against those of Canadian and selected US utilities. Section 2.2 above discusses the rural and remote nature of Hydro One's distribution service territory (i.e., the majority of Ontario, apart from a few urban centers and some smaller population centers). Figure 4 provides a breakdown of service territory by the percent of their system that is either rural and remote, or urban and suburban. Note CNUC received data from only one US peer regarding the percentage of rural versus urban pole kilometers in 2024 and that data is not presented. To compensate for the lack of response to the topic, CNUC accessed data from the 2016 and 2020 surveys for Figure 4.

Only 2% of Hydro One's system is urban or suburban. This operating context is unique compared to other utility groups presented in the figure. The closest group regarding rural and remote percentages is the 2016 peer group at 37% rural and remote. The Canadian utilities responding to our most current study were 76% urban and suburban. This is notable because urban and suburban areas are more easily accessed and managed, which means Hydro One is confronted by the challenges of more ROW kilometers per customer and more travel is required to maintain their system (Figure 5)

Hydro One's distribution system encompasses 103,923 kilometers of ROW, which is twice the 51,470 average of responding Canadian utilities. It is within a standard error of the 80,385 average kilometers of US utilities (Figure 5). However, that average is skewed by a single utility, which reported 209,400 kilometers of ROW, amounting to 3.8 times the average of the other US utilities and over twice as large as Hydro One's system. Without that single outlying utility, US Utility average is 54,574 ROW kms, consistent with Canadian utilities and significantly fewer than Hydro One.

Hydro One serves 1.5 million customers. This is greater than the Canadian utilities' average of 1.08 million, but fewer than the 2.5 million average of the US utilities (Figure 6). The combination of a comparatively large system and moderate customer base combine for a lower customer density than other utilities considered in the 2024 assessment. Hydro One serves only 14.4 customers per kilometer, which is roughly half of the 28.1 customer density of responding Canadian utilities and only 36% of the US Utilities (Figure 7). This is a critical consideration relative to program budget on a per customer basis with rate payers responsible for more line kilometers and a greater number of vegetation conflicts per capita than comparator utilities.

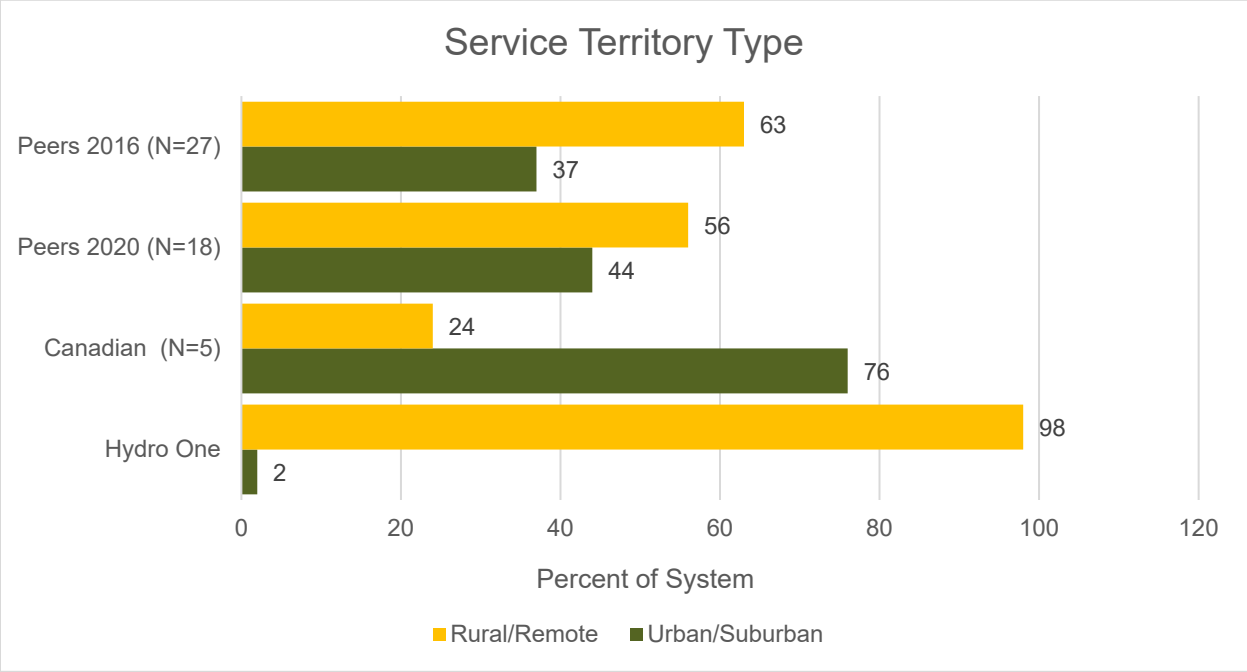


Figure 4. Breakdown of Service Territory

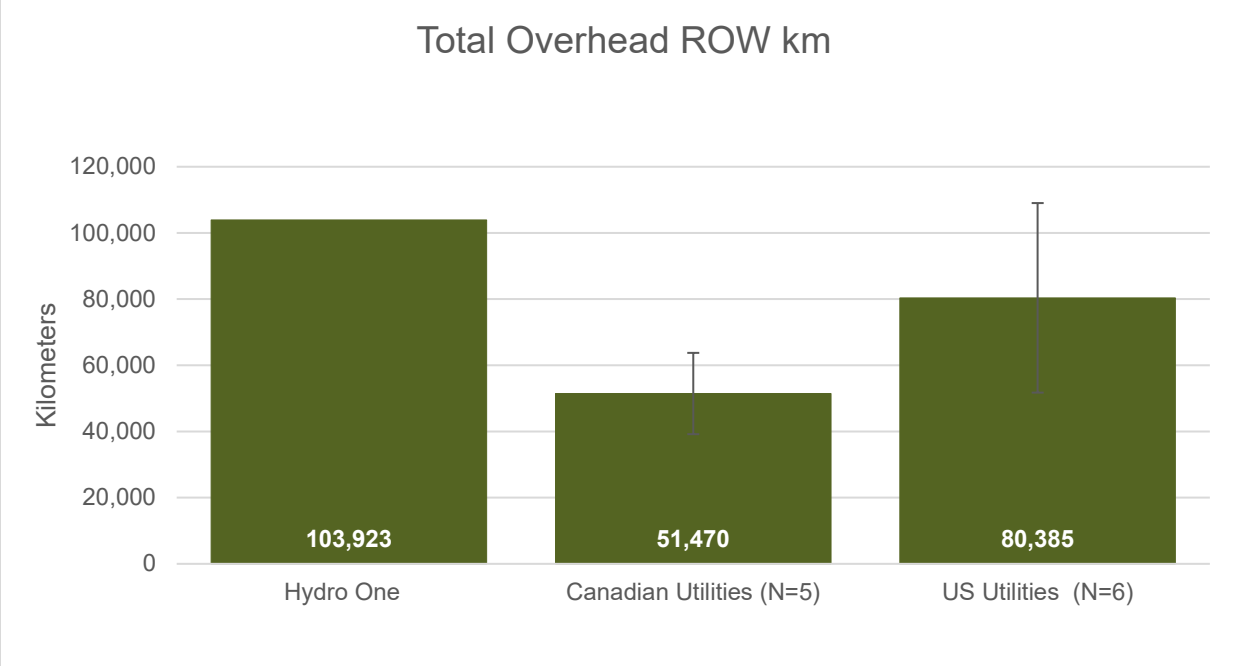


Figure 5. Kilometers of Distribution ROW

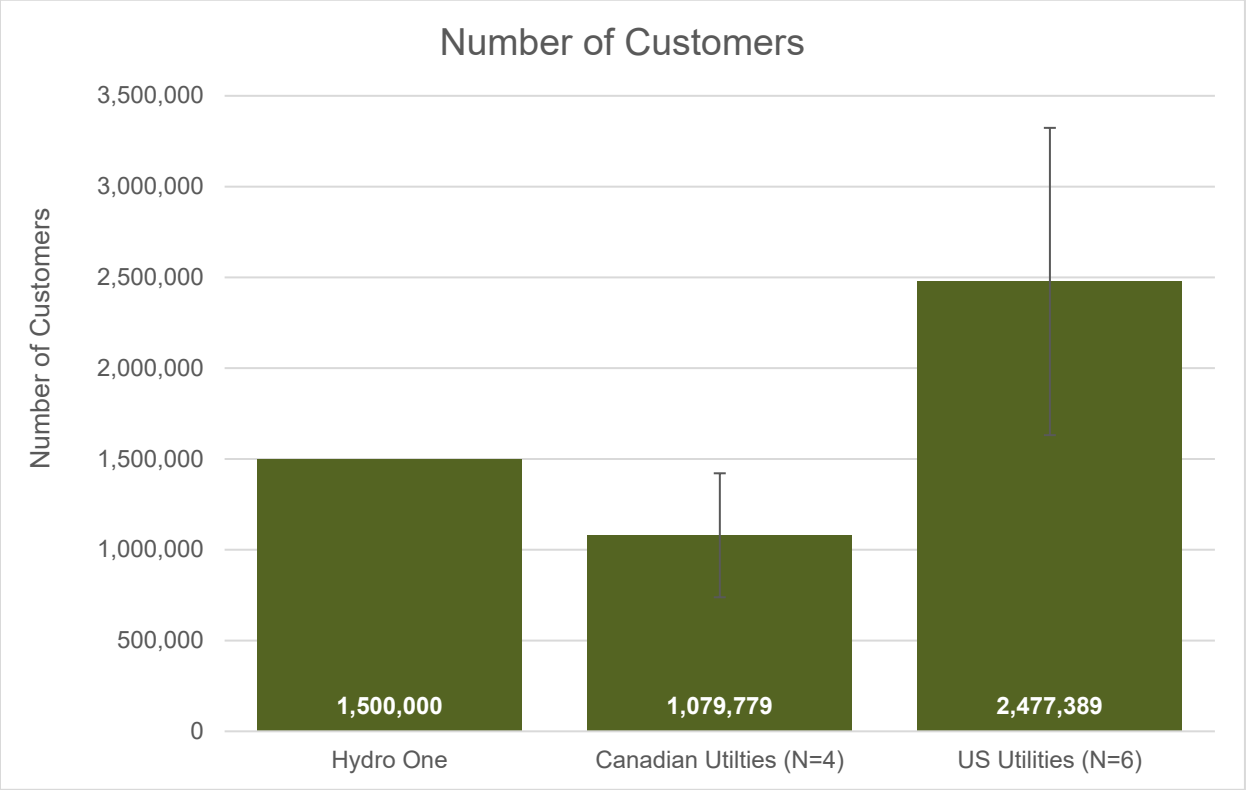


Figure 6. Number of Customers

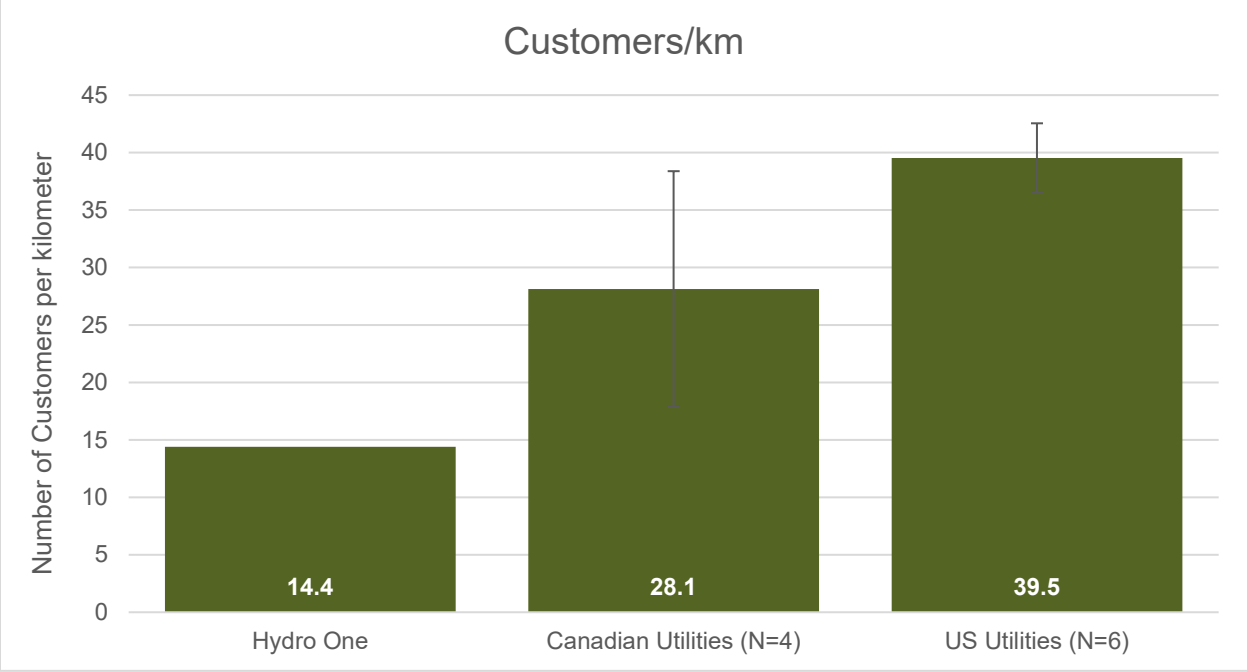


Figure 7. Customers Per Kilometer

3.2 PROGRAM ATTRIBUTES

Following the Clear Path recommendation to increase removal rates particularly in off ROW areas, Hydro One increased their tree removal rate from 20% to 39% in 2020. However, due to reductions in UVM budget, as reported by Hydro One (the vegetation management budget since 2020 decreased 31% in real terms as discussed in Section 3.3.2 below), removal rates fell to 26% in 2024 (Figure 8).

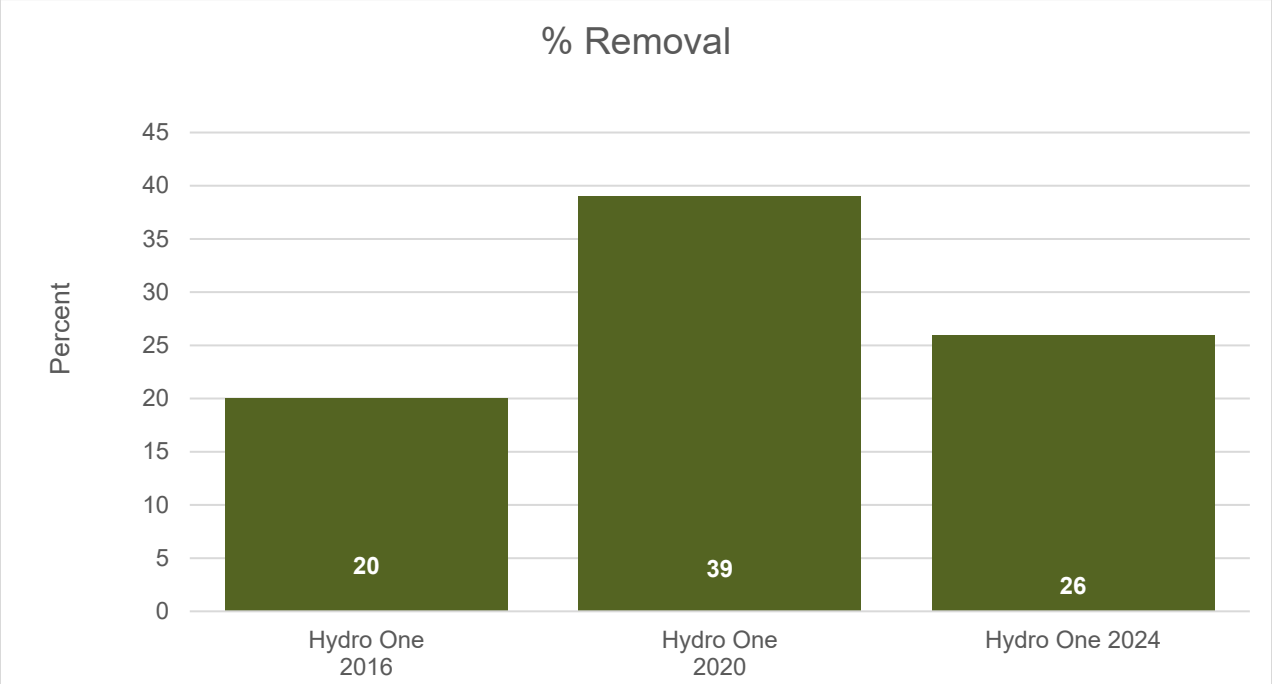


Figure 8. Percent Removal Rate

Removals reduction has the potential to have negative consequences on reliability in coming years. Figure 9 compares post-work clearances for distribution lines as reported for Hydro One and Canadian utilities that participated in this study. At three meters, Hydro One post-work clearances are statistically less than the clearances of the Canadian utilities. Clearances need to be sufficient to keep trees from interfering with conductors for the length of an entire cycle. The reported Hydro One cycle lengths combined with smaller clearances suggests that Hydro One will need to either increase clearances post work, reduce cycle length or both to be successful in continuing to reduce vegetation-caused outages. Hydro One reported treating only 1% of their system with herbicides against the 35 percent of their distribution system where they think chemical control methods could be applied (Figure 10). By contrast, Canadian utilities treated 16% of their system against 23% that could have been treated (Figure 10). That question was not posed to US utilities. CNUC's 2020 report (Chen & Miller, 2020) observed that Hydro One stated 14% of their system was treated with herbicide in 2016, falling to 7% in 2020. The report noted that Hydro One paused most of its roadside brush and spray work to pay for increased high-risk tree work. Currently, without the necessary budget to perform suitable brushing work, the opportunities to apply herbicide post-work, as outlined in the IVM best management practices (Miller 2021), are limited. Consequently, CNUC recommends a restart of the historical brushing program paired with appropriate herbicide application.

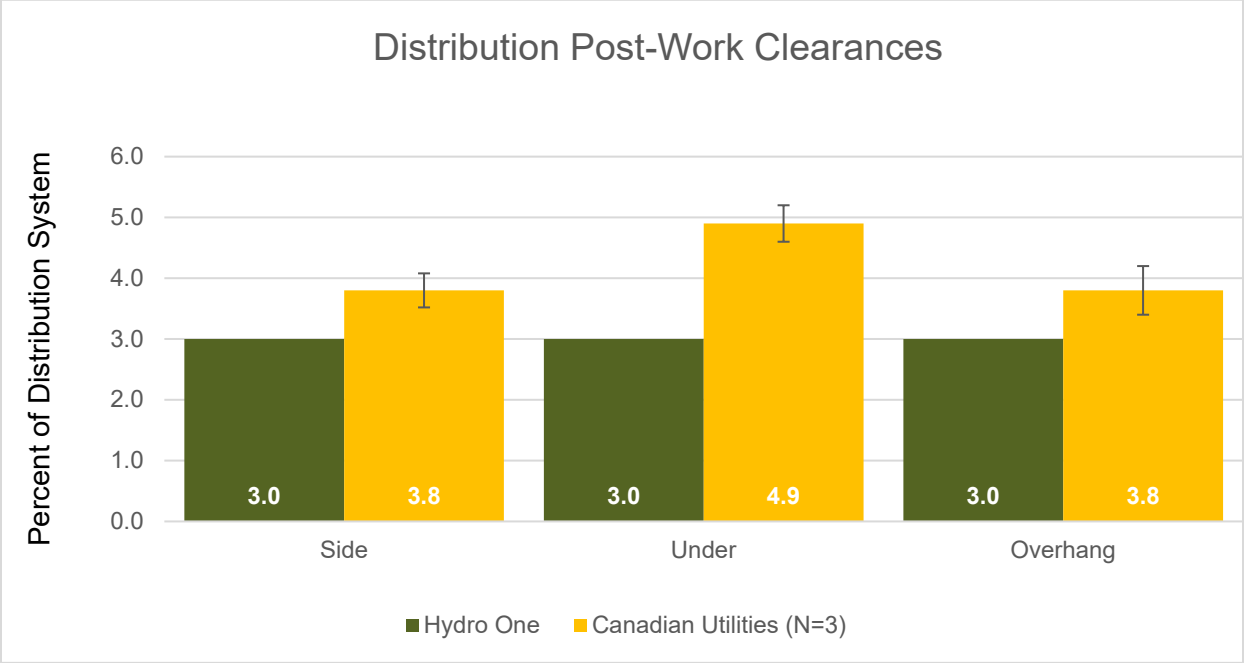


Figure 9. Post Work Clearances (note all overhang is removed for sub-transmission lines)

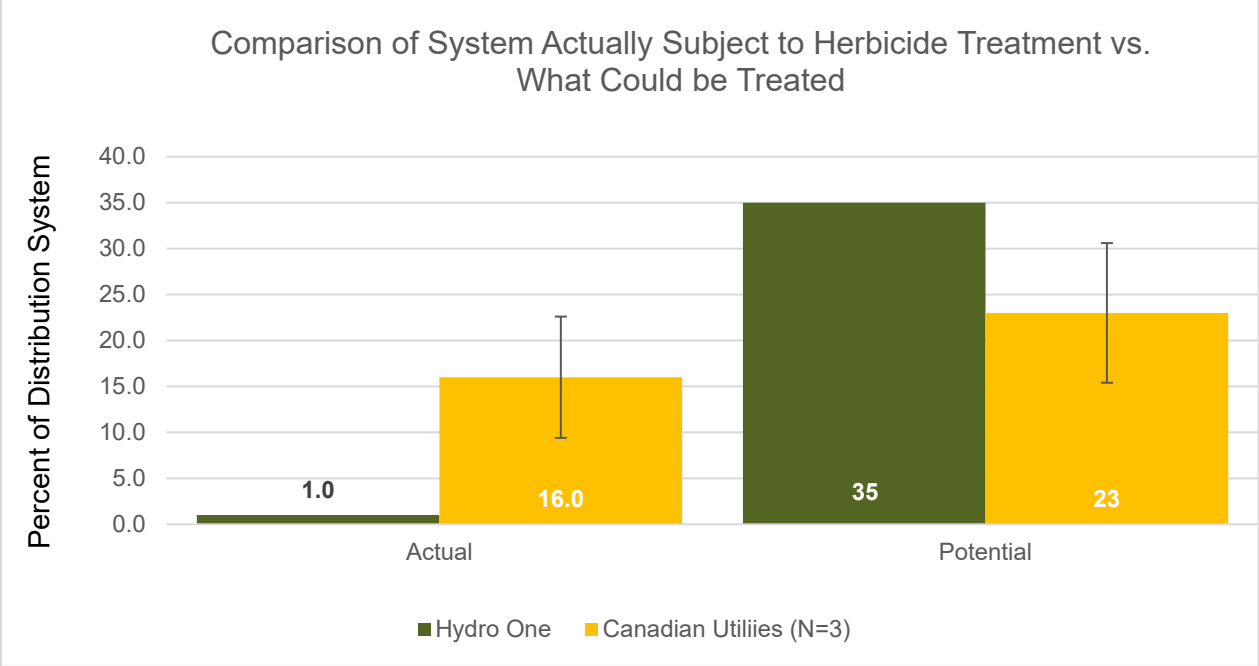


Figure 10. Comparison of the Actual Acreage of Hydro One's System Where Herbicide is Applied Compared to the Percentage Where They Think it Could Possibly be Applied

When trees that re-sprout or root-sucker are removed without herbicide treatment, dense thickets can develop, impeding access, increasing workloads, increasing costs, blocking line of sight, and deteriorating early successional wildlife habitat. This can increase stem counts, workload, and costs over time (Goodfellow, 2019; McLoughlin et al., 2000). For example, a six-year study determined herbicide control could reduce stem counts of trees in the ROW by 70% compared to manual cutting and mastication methods alone (McLoughlin et al., 2000). On the other hand, selectively treating incompatible plants with herbicide creates an opening for early successional or other compatible species to develop and dominate the right-of-way, ultimately reducing workload. For these reasons, Hydro One's Canadian peer utilities have adopted herbicide use, with an average

16% of their systems treated. The long-term consequence of limited herbicide use can lead to increased stem densities throughout a utility system. As noted above, CNUC has reason to believe these consequences may apply to Hydro One's system today.

3.3 OPERATIONAL OUTCOMES

This section reviews and compares key operational outcomes of the current UVM program at Hydro One. The operational outcomes of interest are cycle length, program budget, and reliability metrics. Many of the gains resulting from the UVM strategy change in 2017 have largely been reversed, possibly due to a reduced UVM budget (31% inflation adjusted reduction from 2020 to 2024) and the changes to scope of work, for the sake of mitigating short-term reliability impact, in response to that reduction.

3.3.1 Cycle Length

In 2016, Hydro One reported a 9.5-year cycle. In 2020, Hydro One reduced their cycle to 4.1 years. However, by 2024 Hydro One's cycle had lengthened to 8.3 years. By comparison, Canadian utilities reported a 4.8-year cycle, and the US utilities 4.5 years, both of which were significantly shorter than Hydro One's 2024 cycle (Figure 11).

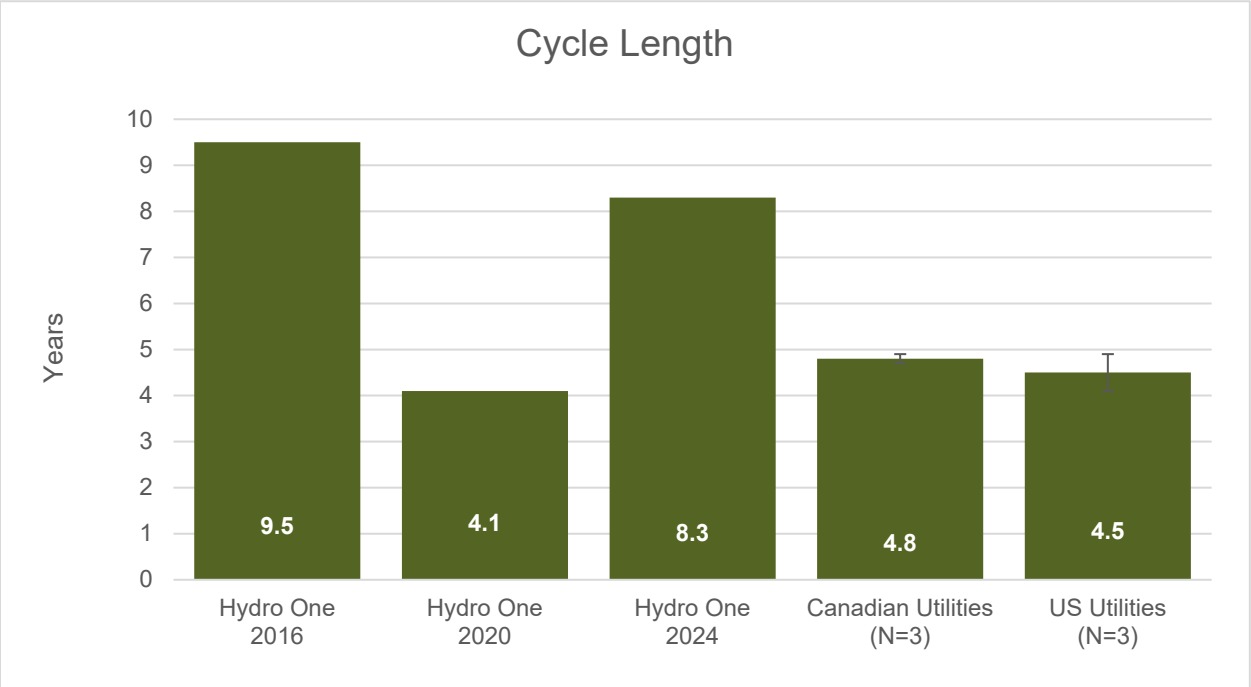


Figure 11. Cycle Lengths

The foundation of a 2017 UVM strategy change was a shift from a corridor to a defect-driven program. That meant a transition from a cycle-based focus of controlling vegetation in a designated ROW to one concentrating on areas of greatest need, driven by response to trees that have encroached into lines as well as high risk off ROW tree removal. This is consistent with integrated vegetation management best management practices, where scheduling is based on vegetative conditions and site parameters (Miller, 2021).

While condition-based scheduling is a best practice, it makes projecting a system-wide cycle problematic insofar as it is founded on dynamic environmental factors rather than static time periods. A dedicated, high-level vegetation assessment could be performed between maintenance intervals to identify areas with higher than anticipated growth or increased tree mortality and reliability risk. That change would be consistent with Clear Path's observation that "contact defects" significantly increase 3-5 years after work (Clear Path Utility Solutions, LLC, 2017). Therefore, Hydro One should consider vegetation assessment between maintenance intervals to enable scheduling and budgeting based on data.

IVM best management practices recommend development of action thresholds and tolerance levels (Miller, 2021). Action thresholds are a level of incompatible plant pressure (like inappropriate species, plant density, height, location or condition) where vegetation management control methods should occur to prevent conditions from each tolerance level. Action thresholds can include specified clearance from conductors, a level of risk of a tree failing and falling into the conductors, or a combination of height and stem density. Tolerance levels are maximum allowable, incompatible plant pressure without unacceptable consequences. Investment levels must be sufficient to control "defects", such as trees in contact at the time of work to a level that delivers safety and reliability to an acceptable degree.

The percentage of trees in contact with lines at time of work is an indicator of the efficacy of time intervals and clearances. This metric is a type of tolerance level. Hydro One reported 31% of trees in contact with conductors at the time of work in 2024, which is nearly unchanged from 30% in 2020. CNUC did not receive enough tree contact data from Canadian and US utilities associated with this study to benchmark Hydro One against. Consequently, CNUC resorted to data from its recent industry surveys. Hydro One's response was not statistically different from the 27.8% reported by the 2020 peer group but was significantly higher than the 17.1% of respondents to CNUC's AR 2024 industry survey (Figure 12). The high number of trees in contact at the time of work compared to the 2024 industry results suggest that cycles could be too long.

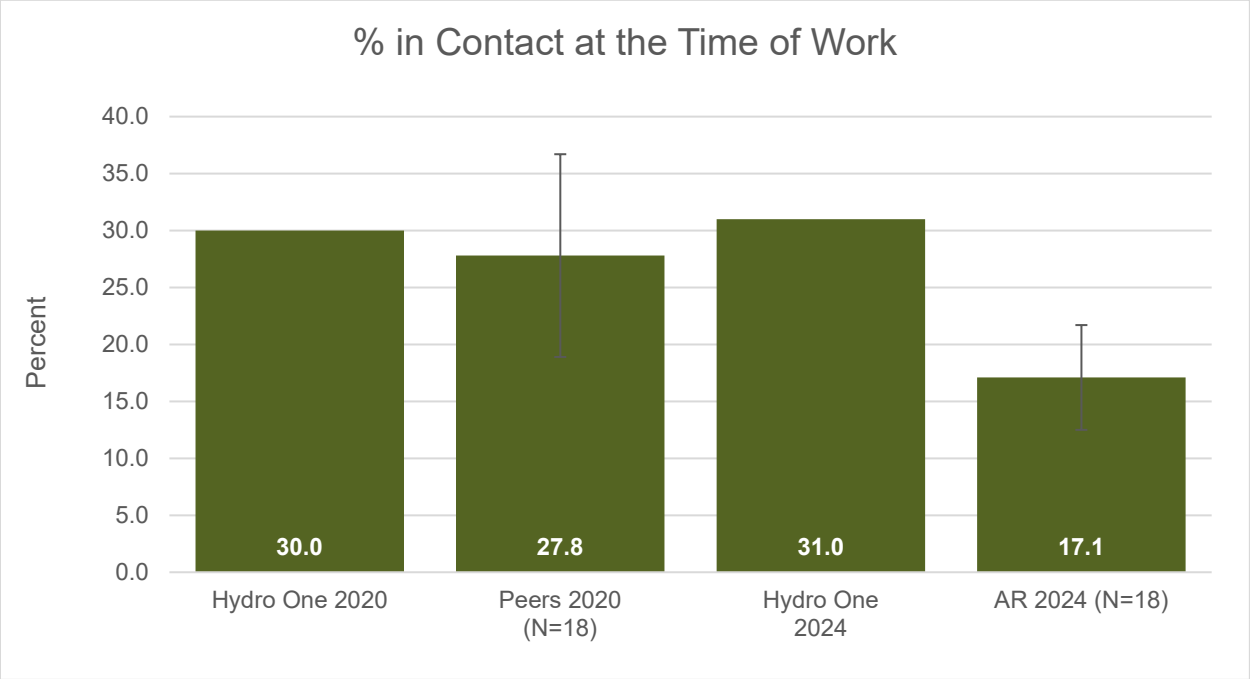


Figure 12. Percentage of Trees in Contact at the Time of Work

Another potential consequence of inadequate clearance or insufficient cycle interval is a high percentage of reactive work (i.e., trees requiring work outside of planned maintenance cycles). Some reactive work is unavoidable ue to storms tree mortality, and other unforeseen circumstances. Hydro One is holding reactive work at 11% in 2024, which is nearly identical to their 10% rate in 2020, and within a standard error of the 16.2% of respondents in the AR survey (Blair et al., 2026). Further, it is significantly lower than the 20.2% reported by Canadian utilities, but significantly higher than the 4.2% of *responding* US utilities (Figure 13).

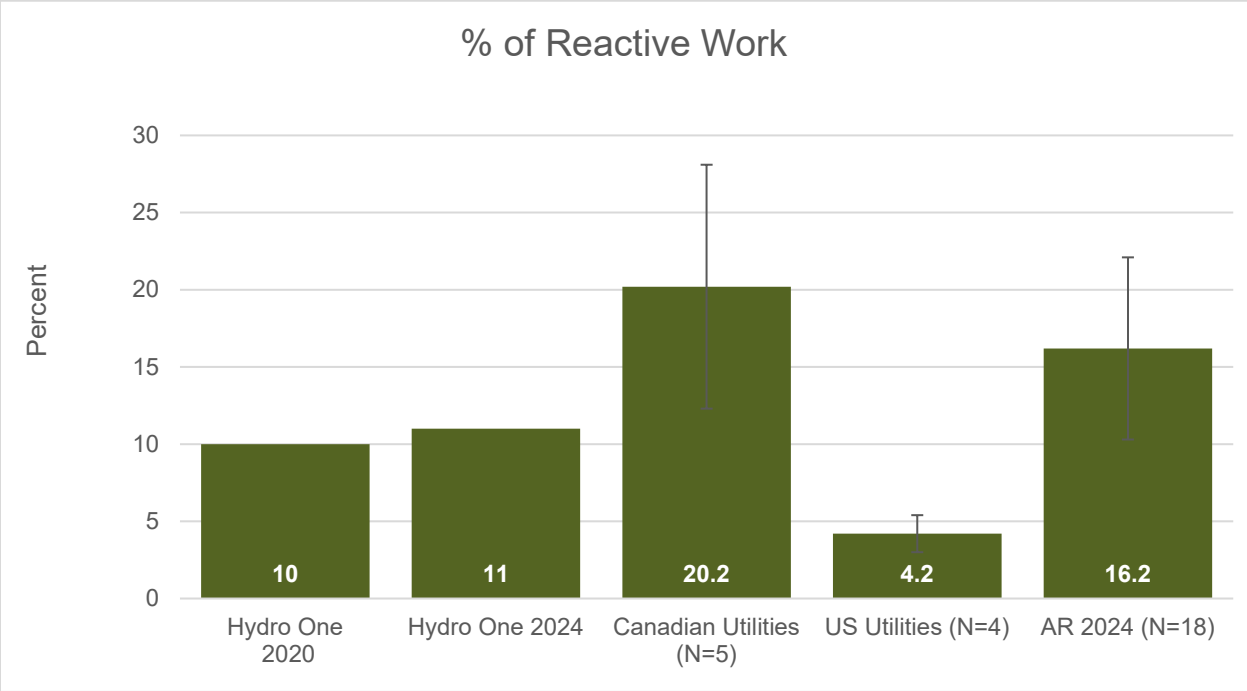


Figure 13. Percentage of Reactive Work

The combination of a relatively high proportion of trees in contact at the time of work and low percentage of reactive work appears to be contradictory. Presumably, many trees growing into conductors would draw a reactive response. There are at least two possible reasons for this apparent inconsistency. The first is a legacy of aggressive tree removals in 2020 (Figure 8). That work possibly reduced the number of trees that posed an imminent threat to Hydro One's facilities, helping to keep reactive work in check over the following years. If that is the case, Hydro One can expect to see their reactive work increase in coming years as their removal rate has decreased over time. Second is discipline on the part of Hydro One staff in limiting reactive work to the most critical short-term conditions and remaining diligent in correcting imminent reliability threats during routine maintenance work. The reality is likely a combination of these two factors.

3.3.2 Budget

Hydro One's reported 2024 UVM budget was $129 million, which is down 7.3% from the reported 2020 UVM budget. However, the Canadian economy saw inflation of 24.8% between 2020 and 2024 (Bank of Canada, n.d.), meaning the 2024 budget was reduced over 31% in real terms over the period. On the other hand, Hydro One's 2024 vegetation management budget is 3.8 times the average $33.8 million 2024 UVM budget of responding Canadian utilities. Hydro One's vegetation management budget is not significantly different than the $114.6 million (CAD converted) average of US peer utilities identified in CNUC's 2024 industry survey (Figure

14). Hydro One reported their UVM budget to be significantly lower than needed for sustainable UVM. That isn't surprising, given the inflation adjusted 31% decrease from 2020 to 2024.

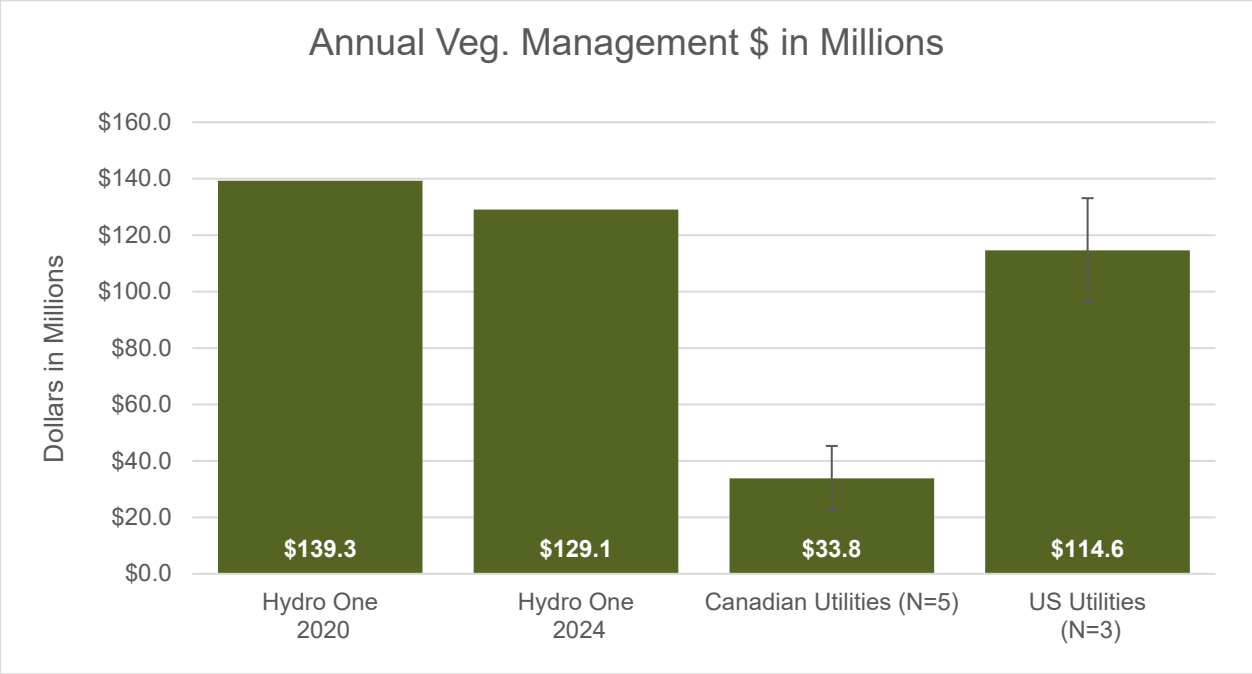


Figure 14. Vegetation Management Budget in Millions

Hydro One's dispersed customer base is another factor impacting budgetary need. It means there are more line kilometers to manage per customer than other contributing utilities. Hydro One has 14.4 customers per kilometer, which is only about 50% that of responding Canadian utilities and 36% of the 39.5 customers per kilometer of US utilities (Figure 7). That explains Hydro One's relatively high cost per customer. At $86.07, 2024 UVM cost per customer is 2.75 times higher than the $31.28 cost of Canadian utilities (Figure 17). However, when compared to earlier production, we find the 2024 cost per customer is 21% lower than its $109.59 value in 2020 (Figure 17). That figure comes to over 36% if adjusted for inflation (Bank of Canada, n.d.).

Hydro One's 2024 cost to remove a tree is $805, which is nearly double their unit cost of pruning at $409. That is understandable, as removals focus on trees with "defects", or conditions that present an unacceptable risk. Hydro One's removal cost is higher, but not significantly, than the $644 removal cost reported by Canadian utilities (Figure 18).

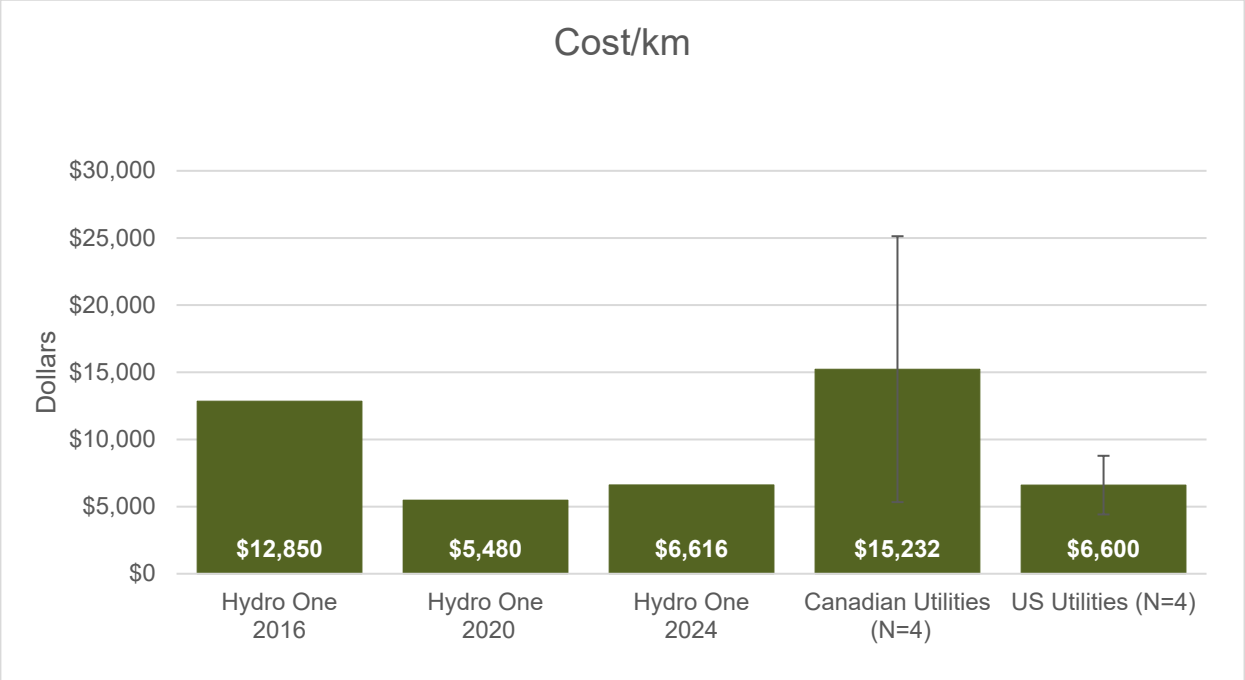


Figure 15. Cost per Kilometer

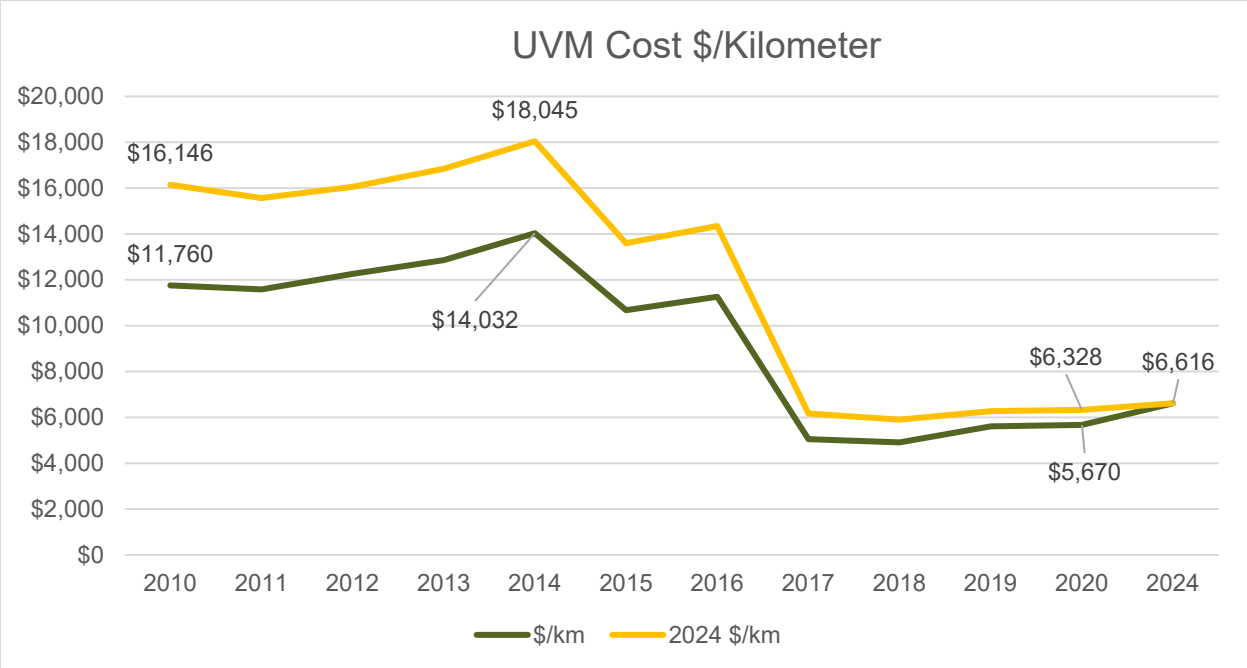


Figure 16. Hydro One UVM Cost per Kilometer 2010-2024 (green line actuals vs. gold line normalized to 2024 dollars)

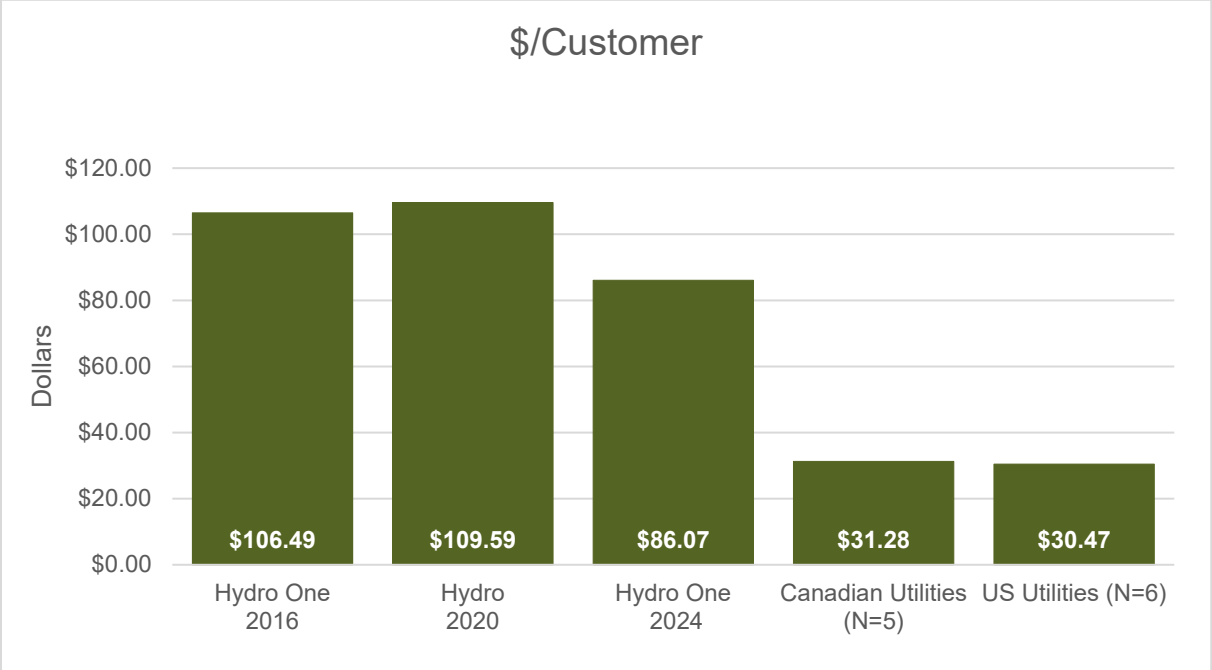


Figure 17. Cost per Customer



Figure 18. Cost to Remove a Tree

3.3.3 Reliability

Hydro One's vegetation-caused SAIDI grew gradually from 2010 to 2017 when it peaked at an average of 3.6 hours per customer per year. Since then, it has gradually declined to an average between 2021 and 2024 of 2.5 hours per year . It stood at 2.9 in 2024, which is a 19.4% improvement from the 2020 peak (Figure 19). In spite of that improvement, Hydro One's average vegetation-caused SAIDI for the period 2021-2024 was 2.5 times the 1.0 hours of responding Canadian utilities (Figure 20). The 1.0 hours of Canadian utilities is slightly low compared to results of CNUC'S 2024 survey, where 30 North American utilities averaged 1.4 hours of vegetation SAIDI a year (Blair et al., 2026). However, Hydro One's vegetation-related SAIDI for 2021-2024 is still 1.8 times that number. On the other hand, Hydro One had an average of 7.5 non-major event day[2] (MED) vegetation related outages per 100 kms of line for the period 2021-2024, which was not significantly different that the 7.2 average reported by Canadian utilities (Figure 21).

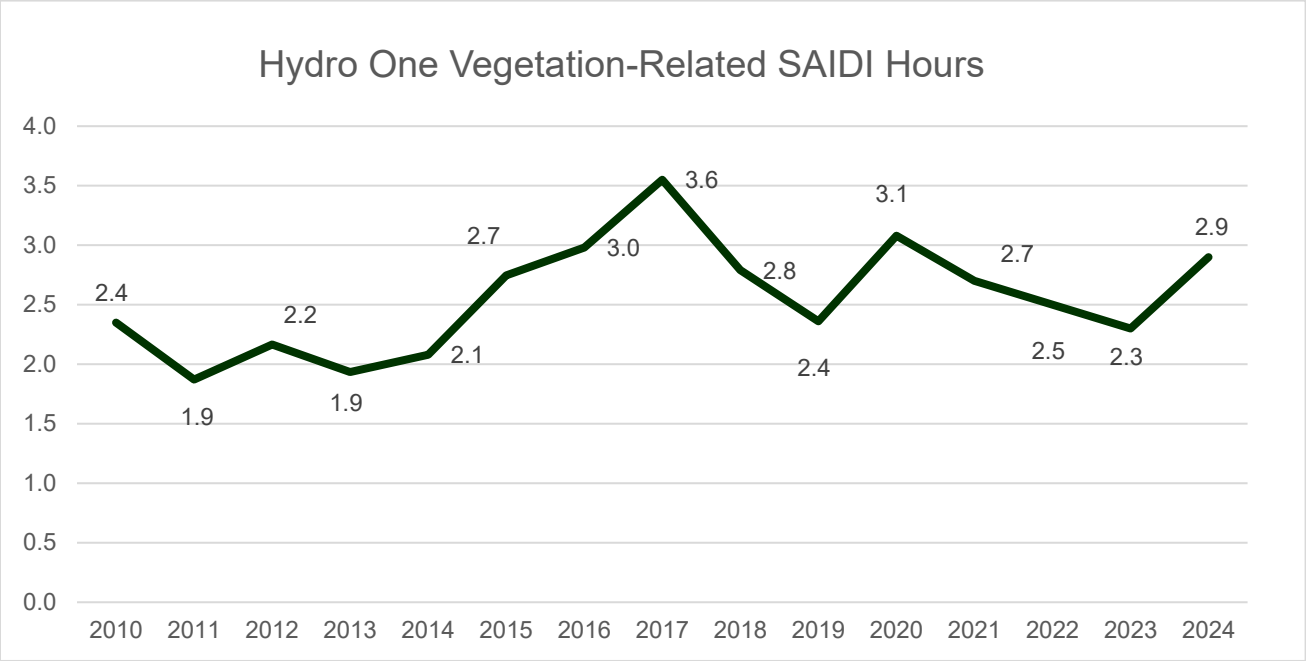


Figure 19. Hydro One Vegetation-related SAIDI 2010-2024

Vegetation-caused outage reduction and positive results in moderating non-MED event days can be attributed to the implementation of the 2017 UVM strategy changes (Clear Path Utility Solutions, LLC, 2017). The assessment leading to the strategy change determined approximately 90% of all Hydro One vegetation-caused outages resulted from off-ROW tree or branch failures. Hydro One has responded by devoting 27% of their 2024 UVM Budget to addressing off ROW trees, which is significantly more than responding Canadian utilities (Figure 22). A secondary benefit of the relatively high removal rate is Hydro One holding their reactive work in check (Figure 13). Hydro One should renew focus on high-risk tree removal to continue focusing on improving SAIDI and moderating inefficient reactive work.

[2] A non-major event day outage is an outage that occurred outside of an event (storm, fire or other emergency) declared by the utility.

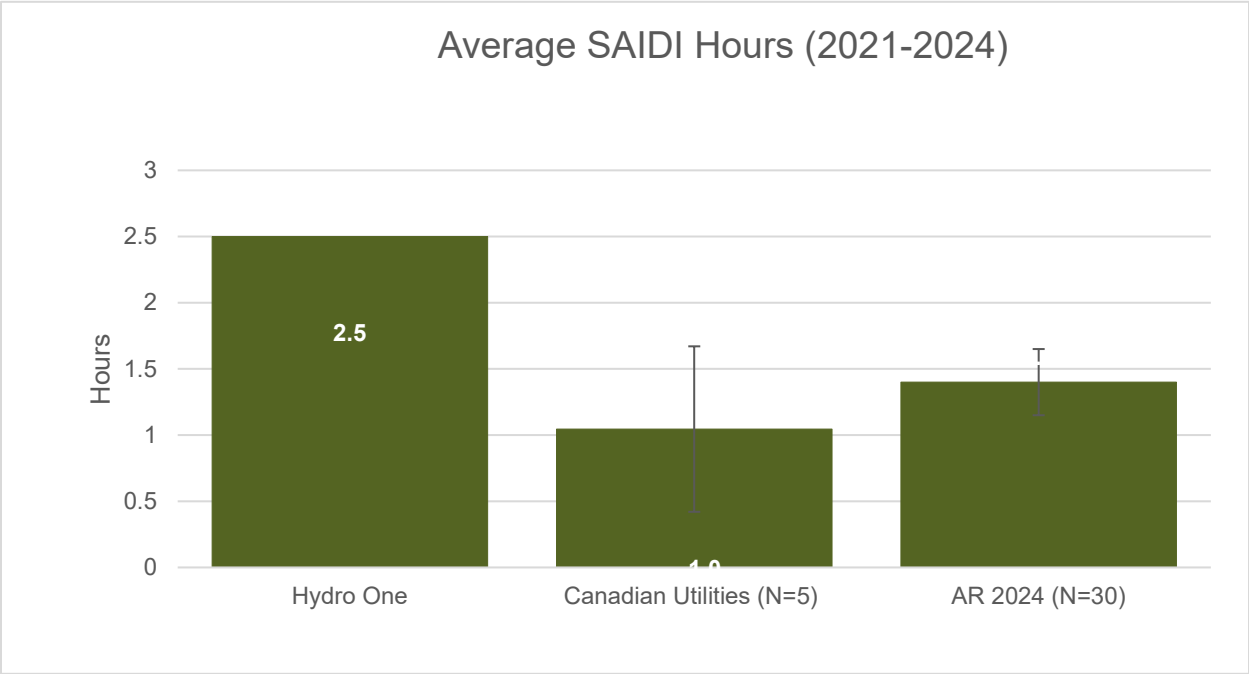


Figure 20. Average Annual Vegetation-Related SAIDI 2021-2024

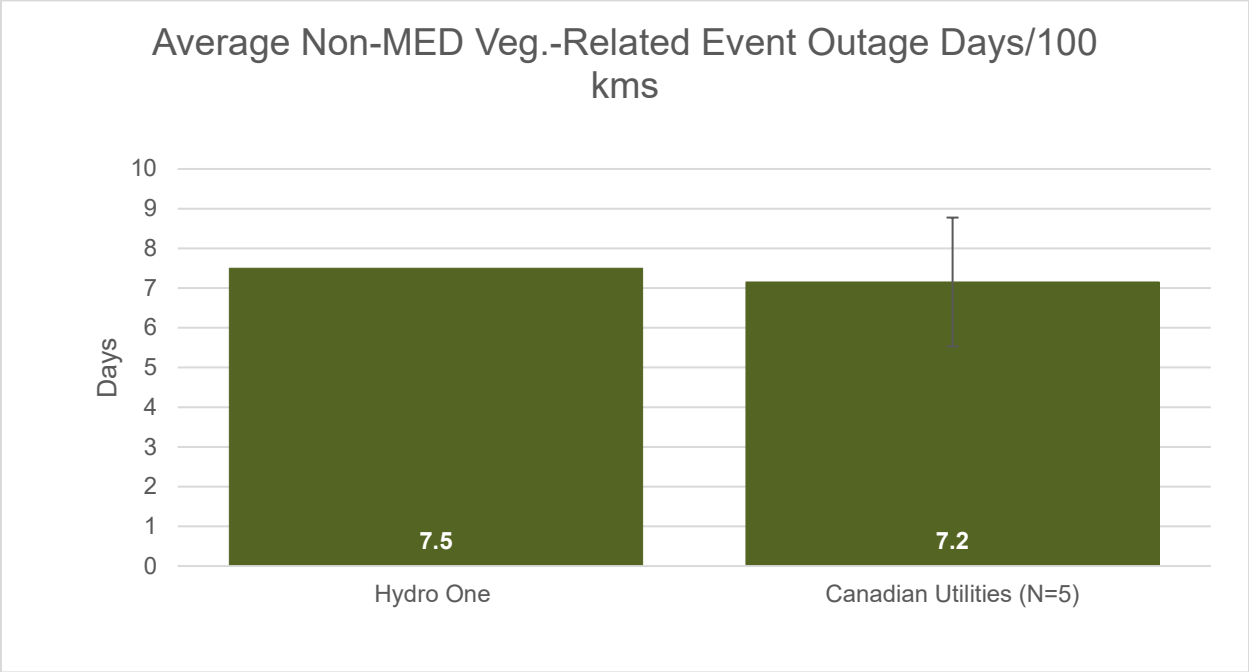


Figure 21. Average Non-MED Event Days Veg.-Related Outages 2021-2024

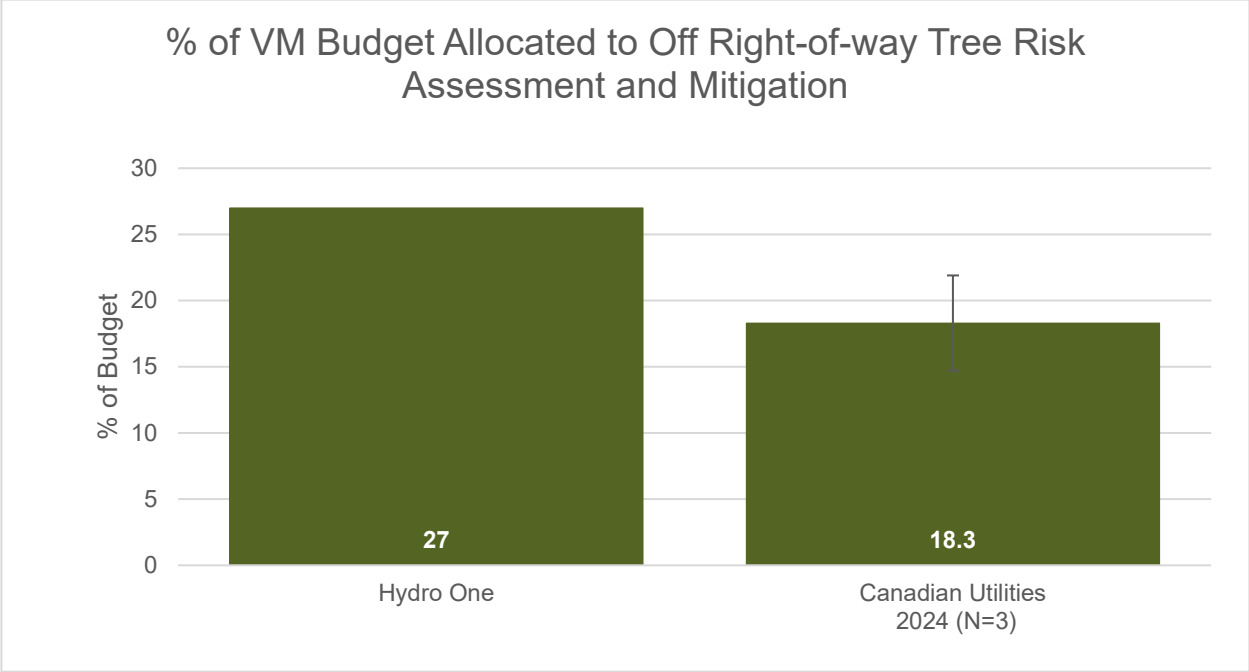


Figure 22. Percent of VM Budget Allocated to Off Right-of-Way Trees

4.0 Key Findings & Recommendations

CNUC offers the following key findings in system attributes, program attributes and operational outcomes.

- Hydro One's customer density is significantly lower than comparators. Only about half of the 28.1/km average of responding Canadian utilities and 36% of US utilities (Figure 7).
- Largely due to low customer density, Hydro One's cost per customer is roughly 2¾ times greater than the Canadian and US utilities in this study (Figure 17).
- Hydro One's vegetation management budget fell an effective 31% in 2024 from 2020, after inflation adjustment. That has resulted in an 8.3-year cycle, which is unsustainably long (Figure 11). Hydro One should re-establish their budget to adequately maintain a sustainable cycle in line with the 4-5 year industry average but adjusted to vegetative conditions in a particular area.
- Further, inadequate investment has not allowed tree crews to reduce the percentage of trees in contact at the time of work (Figure 12). This has forced the deferral of brush removal and herbicide application as a means of limiting short-term reliability impacts. These factors threaten to allow the workload to build and costs to rise in the long term.
- Cycle length has influence over two other factors: post work clearances and trees in contact at the time of work. Hydro One's post-work clearances are less than those of other reporting utilities (Figure 9), the comparatively high percentage of trees in contact at the time of work are a consequence of extended cycle length being too long and insufficient clearances. Modifying either or both based on vegetative conditions addresses this issue. Increasing removal rates will also help Hydro One optimize its cycle length and budget.
- Hydro One should also implement a brush (sapling) control program. That means a combination of physical removal (mechanically or by hand), and herbicide application wherever it can be applied. Over the past decade, IVM encourages conversion of the ROW to appropriate low growing plant communities.

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6.0 Team Bios

Randall Miller, Subject Matter Expert



Randall H. Miller is a recognized authority in Utility Vegetation Management. He joined CNUC in 2017 after more than 23 years as Director of Vegetation Management for PacifiCorp, a utility serving six states in the northwest quarter of the continental United States. PacifiCorp has 45,000 miles of overhead distribution lines and 16,000 of transmission, half of which are subject to FAC-003. Miller also served six years on ACRT's Board of Directors.

He has been Chair of the TREE Fund Board of Trustees, President of the Utility Arborist Association, twice Chair of the Edison Electric Institute Vegetation Management Task Force and a Director on the International Society of Arboriculture (ISA) Board where he Served on the Executive Committee and Chaired the Governance Committee. He has also served on the ISA Certification Test and Appeals Committee, as and many other industry committees. He has roughly 100 publication credits, including the ISA Integrated Vegetation Management Best Management Practices (Miller 2021) and, with Geoff Kempter, the Utility Specialist Study Guide (Miller & Kempter 2018). He served on the drafting team of the first two versions of the North American Reliability Corporation's Vegetation Management Standard (FAC-003). He was vice chair the Electric Hazard Subgroup of the American National Standard for Safety in Arboricultural Operations (ANSI 2024) and was an alternate in the Review Committee of ANSI A300 (American National Standards Institute, 2023). He speaks widely on arboricultural topics and performs formal UVM surveys of North American utilities. He also is an adjunct faculty member at the University of Wisconsin-Stevens Point where he is a facilitator for the Professional Utility Vegetation Management Credential program. At Eocene, Miller conducts UVM program reviews, leads on industry surveys and provides expert witness testimony.

Bachelor of Science, Horticulture. University of Wisconsin - Madison | Master of Science, Urban Forestry. University of Wisconsin – Stevens Point | ISA Board Certified Master Arborist | ISA Certified Arborist Utility Specialist | ISA Tree Risk Assessment Qualified

Industry Awards & Noteworthy Publications

2005 ISA RW Harris Author's Citation recipient | UAA President's Award (twice) | UAA Education Award | Utility Arboriculture: The Utility Specialist Certification Study Guide (Miller and Kempter 2018) | Best Management Practices – Integrated Vegetation Management, Third Edition (Miller 2021)

RYON BIRTSCH, RESEARCH AND DEVELOPMENT



Ryon joined CNUC in 2018 as a field arborist collecting over 8 years' experience in the planning and execution of project awards. He has since supervised UVM work in over a dozen states, primarily in the southeastern United States. In 2024 he moved to Alberta and managed CNUC of Canada. This included providing training, oversight, and consultation services in the western provinces of Alberta, British Colombia, and Saskatchewan. He has experience in all aspects of utility forestry including field work, UVM program management, management plan writing, benchmarking, and workload assessment. His formal education includes Biology and Forest Resources Management.

B.S. Biology | M.S. Forest Resources Management Course work | ISA Certified Arborist SO-11075A | UAA Canadian Taskforce member

Distribution Pole and Substation Transformer Benchmarking Study

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Reference No.: 228649
August 26, 2026

guidehouse.com

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Executive Summary

Guidehouse Canada Ltd. (Guidehouse) and First Quartile Consulting (1QC or First Quartile) conducted a benchmarking study for Hydro One Networks Inc.'s (Hydro One or HONI) distribution poles and substation transformers.

This report provides an overview of the study approach and results. It offers insights into Hydro One's distribution pole and substation transformer replacement and refurbishment rates, inspection and maintenance practices relative to a comparison group of utilities. Primary findings from the study are highlighted below.

Distribution Poles

- Hydro One pole replacement and refurbishment practices are primarily driven by condition rather than age, in line with the comparison group; while many pre-1960 poles exceed their nominal service life, they are not automatically replaced unless inspections indicate their condition no longer meets acceptable remaining life criteria.

- The expected service life of 62 years for Hydro One's wood poles is above the 51-year average for wood poles for the comparison group. Hydro One's wood pole fleet has an average age of 43 years—slightly above the 42-year comparison group average—assuming comparison utilities' poles with unknown installation dates are among the oldest assets in their populations.

- Hydro One's annual pole replacement rate for exclusively planned replacement activities in 2024 was 0.3 percent, which was marginally below the median of the comparison group. The annual rate for planned and expected replacements over the next 5 years (2025-2029) for Hydro One is projected to be 0.2 percent, which is lower than the comparison group median of 0.78 percent.

- Hydro One's service territory covers more surface area than the average comparator and includes a significant proportion of rural and remote locations.

- The average number of customers served by Hydro One distribution circuits per kilometer is among the lowest in the comparison group.

- The largest share of Hydro One poles were installed pre-1960, with additional concentrations from the 1960s–1970s.

- Hydro One's six-year visual inspection interval is more frequent than the comparison group's 10-year average but is consistent with Ontario Energy Board (OEB) inspection requirements; its pole testing interval of 15 years is longer than the 10-year average for the comparison group.

Distribution Substations

- Hydro One's distribution substations typically serve rural areas with low load density versus the comparison group. The number of transformers per distribution circuit kilometer is among the lowest in the comparison group.

- Most Hydro One substations are equipped with one transformer with low side voltages predominantly rated 9 kV and below. Other utilities in the comparison group include up to two or four transformers per station with higher low side voltages, mostly 15kV (e.g., 12.47kV)

- Hydro One's substation transformers operate at an average peak loading of about 75 percent (as a percentage of nameplate capacity) and is the highest among the reporting utilities—whereas others in the comparison group typically have an average loading of below 75 percent, which enables contingency support and tie transfer schemes.

- Hydro One employs a range of approaches for planned substation equipment inspections, with time-based methods as the primary focus for most components, and condition-based approaches following closely behind. Overall, Hydro One's practices are broadly aligned with those observed across the comparison group.

- The average age of Hydro One's distribution transformers is 42 years, which is above the comparison group average of 35 years. Hydro One's distribution transformers show a relatively even age distribution across the past six decades, with installations peaking in the 1970s.

- Hydro One's 2023-2024 distribution transformer annual replacement rate was 0.04% (reflecting a single project), increasing to a projected 0.32% for 2025–2029—below the comparison group median of 0.88%. For the purposes of this study, replacement activity is limited to condition-based needs and excludes load growth expansion.

1. Introduction

1.1 Study Objectives

This study provides a comparative analysis of Hydro One's asset management practices with respect to replacements, refurbishments, and inspection practices for distribution poles and substation transformers to those of comparable North American electric utilities. In brief, the study was designed to:

- Determine Hydro One's inspection and testing practices, replacement and refurbishment rates for distribution poles and substation transformers; and
- Benchmark those practices and replacement rates relative to a comparison group of utilities.

1.2 Overview of Approach

Guidehouse and First Quartile identified a group of utilities representative of the utility industry and identified relevant business and operational characteristics that would be useful for comparisons. The comparison group includes electric utilities that own and operate distribution assets.

Specifically, the benchmarking study was structured to:

- Include a representative group of utilities to reflect industry characteristics and asset demographics relevant to the benchmarking objectives; and
- Ensure a common understanding of the comparison criteria using clear definitions and engagement processes that allow transparency for all participants.

This study leveraged data collected from the annual benchmarking survey conducted by First Quartile for its current participant group and its underlying database of demographic information for poles and transformers. It also involved additional activities that included preparing a supplemental questionnaire designed to request data that are not part of First Quartile's annual program, and by adding publicly available data from Canadian utilities. The study included gathering the required demographic and operating data from Hydro One and the comparison of similar utility data to enable fair comparisons. The study included the development of a series of graphs of relevant metrics, and conclusions drawn from an analysis of the various graphs and benchmarking results.

Guidehouse and First Quartile made efforts to collect unit cost data for both distribution poles and substation transformers including breakdowns by cost components such as materials, labour, and transportation etc. However, the level of detail provided in responses was insufficient at this granularity and responses were limited to support a meaningful comparison. As a result, transformer and distribution unit costs were excluded from this report. This reflects a broader, industry-wide challenge, as utilities often have reservations about sharing cost

information and there is significant variation in how costs are defined and tracked across organizations. For example, differences in transformers ratings, voltages, number of transformers installed per substation and support structures create potential cost variances among reporting utilities that preclude accurate comparison of unit costs. Given these limitations, no conclusions could be drawn regarding Hydro One's transformer and distribution pole unit costs.

1.3 Content of Report

The report is organized with results presented as outlined in the following two sections:

Section 2 – Benchmarking Process: Presents insights about the benchmarking process and methodology used for comparison group selection, data gathering, and analyses.

Section 3 - Benchmarking Observations: Summarizes findings related to the age, replacement rates, inspection practices of distribution poles and transformers.

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 operating practices. Benchmarking is an output-based assessment and understanding of operating practices of comparable organizations. It is important to normalize findings in such a way that data, trends and findings can be understood and lead to supportable insights and conclusions.

For this study, benchmarking was conducted to obtain information from utilities owning and operating distribution assets, with responses in sufficient detail to understand the practices of those companies (from an industry perspective). The objective is to identify similarities to or differences in benchmark metrics to those of Hydro One. There are three sub-sections within this section.

1) **Overview** – a brief overview of the primary steps and methodology applied in the benchmarking process

2) **Information collected** – the data gathered for the comparisons, both from Hydro One and the comparison group

3) **Comparison group selection** – details for the Canadian and U.S. utility study participants

2.1 Overview & Methodology

The study was designed to provide comparisons of Hydro One's distribution wood pole structure and substation transformer replacement rates and asset management practices to other distribution providers.

Key steps Guidehouse and First Quartile followed to conduct the study included,

- **Project Initialization** – Determining the appropriate comparison group, relevant demographic data, and benchmark metrics

- **Quantitative Analysis** – Methods applied to conduct the benchmarking analysis

    - Data Requirements and Survey Questionnaire – Identify data available from the First Quartile annual survey together with topics from a supplemental questionnaire needed to conduct the benchmarking analysis.

    - Data Collection, Verification and Normalization – Gathering and verifying data through a detailed questionnaire directly completed by participating utilities, followed by normalization and data validation.

- Supplemental Data Collection – Expanding data set to include publicly available information for Canadian utilities.
- Statistical Findings – creating statistical summary graphs comparing results.

- **Post Analysis** – Review results, findings and conclusions for Hydro One distribution pole and substation transformer demographics, configuration and replacement practices.

2.2 Information Collected

The project team gathered two types of information from each of the participating companies needed to compare replacement rates and asset management practices for wood poles and substation transformers. Table 1 and Table 2 summarize primary information collected from the comparison group for wood poles and substation transformers. Distribution system demographics were used to compare assets statistics within the comparison group. Operational practice information was used to compare replacement rates and approaches for replacing poles and installing transformers.

Table 1. Information Collected from Hydro One and the Comparison Group for Distribution Poles

Demographic Information	Practice Information
✓ Service territory customers per square km	✓ Wood pole inspection and treatment intervals
✓ Number of customers per circuit kilometer	✓ Expected service life of wood poles
✓ Age of wood poles	✓ Priority ranking for wood pole replacement
✓ Distribution poles by material type	✓ Number of poles replaced in 2024
	✓ Plans for wood pole replacements over the next 5 years (2025 to 2029)

Table 2. Information Collected from Hydro One and the Comparison Group for Substation Transformers

Demographic Information	Practice Information
✓ Number of distribution substation transformers per distribution circuit ✓ Number of distribution substation transformers by voltage class ✓ In-service age of distribution transformers	✓ Expected service life of substation transformers ✓ Average transformer loading % at coincident peak ✓ Transformer inspection and maintenance intervals ✓ Number of transformers replaced in 2023-2024[1] ✓ Planned transformer replacements over the next 5 years (2025 to 2029)

2.3 Comparison Group Selection

The comparison group began with the participants in First Quartile's annual benchmarking study, which makes up a reasonable representation of the North American utility industry. This population of utilities were invited to complete a supplemental survey covering topics outside the specific questions in the annual survey, and nine of them provided responses to that supplemental questionnaire. Some responded to the distribution poles part of the questionnaire, some only to the substations portion, and some to both. A couple of the participants were removed from the comparison group because they do not have distribution assets that are appropriate for comparison to Hydro One. The resulting comparison group was then expanded by including Canadian utilities with information obtained via publicly available sources.

Figure 1 lists the utilities represented in the comparison group, which includes a mix of mostly larger U.S. and Canadian utilities. Figure 2 illustrates the location of each utility. They represent the industry from the standpoint of those experiencing various weather patterns, having both low-density and higher-density portions of service territory, and having similar and different regulatory circumstances from Hydro One.

[1] Two years of transformer replacement data were collected, compared to one year of pole replacement data, to account for the longer planning and execution timelines typically associated with transformer replacement projects. Unlike pole replacement activities, transformer projects may span multiple calendar years from initiation to completion, making a two-year data collection period more representative of actual replacement activity.

Figure 1. Comparison Group

1. Alectra*
2. Arizona Public Service*
3. Austin Energy
4. CenterPoint Energy – TX*
5. CPS Energy
6. Entergy – Arkansas*
7. Entergy – Louisiana*
8. Entergy – Mississippi*
9. Entergy – New Orleans*
10. Entergy – Texas*
11. Exelon – BGE
12. Exelon – PECO
13. Exelon – Atlantic City Electric
14. Exelon – Delmarva
15. Exelon – Pepco
16. Hydro One*
17. Hydro-Québec*
18. Manitoba Hydro*
19. Northern Virginia Electric Coop*
20. Omaha Public Power District
21. Oncor Electric Delivery*
22. Pacific Gas & Electric
23. Public Service Electric & Gas
24. PSEG Long Island*
25. Tucson Electric Power*

Utilities responding to specific survey questionnaire or included publicly available data indicated with an asterisk (*)

Figure 2. Survey Participants Locations



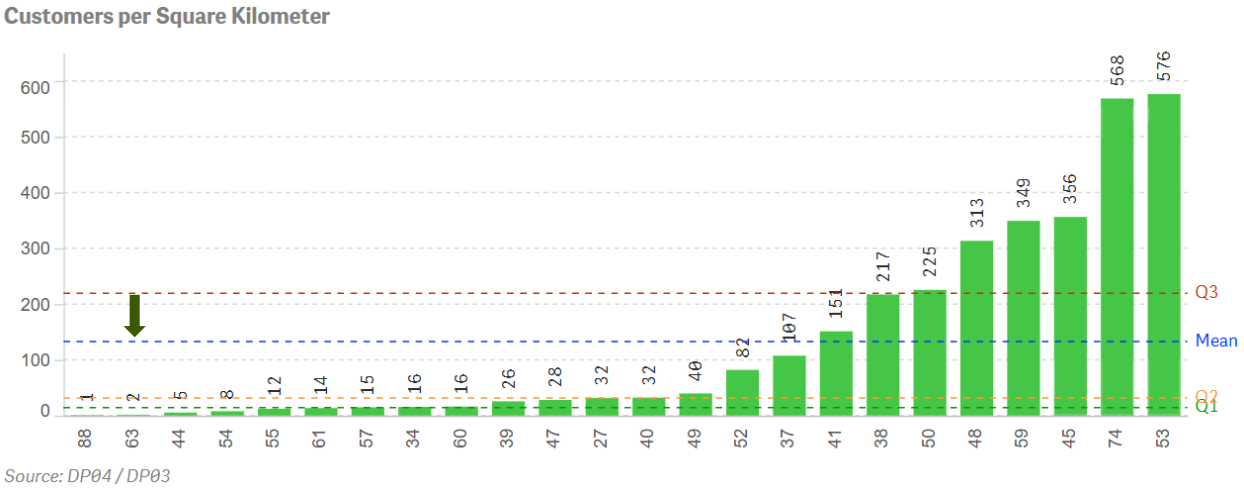
3. Benchmarking Observations

This section summarizes the primary findings of the study via a series of observations of benchmark survey results. Findings are informed by benchmark comparisons of asset age, expected service life, and replacement rates, among other factors. In the graphs that follow, Hydro One is identified with an arrow for ease of identification. The values for the range of quartile results (i.e., Q1, Q2, and Q3), where applicable, are the values for the minimum or maximum for entry into first quartile, second quartile, and third quartile respectively, depending on whether the first quartile represents lower or higher values.

3.1 Demographics & Statistics

The comparison group covers a wide range of customer densities. Figure 3 presents service territory density for customers receiving direct service from Hydro One 's distribution lines and substations to those of the comparison group. Over half of the comparison group have relatively low customer densities. Even with the low customer density utilities, Hydro One remains an outlier with only 2 customers per square kilometer.

Figure 3. Service Territory Density



The following two sections present separately Hydro One's distribution pole and substation transformer statistics.

3.1.1 Distribution Poles

Figure 4 presents Hydro One's distribution customer density per kilometer of circuit versus the comparison group. The low customer density highlights the rural nature of Hydro One's distribution system.

Figure 4. Customers per Distribution Circuit Km

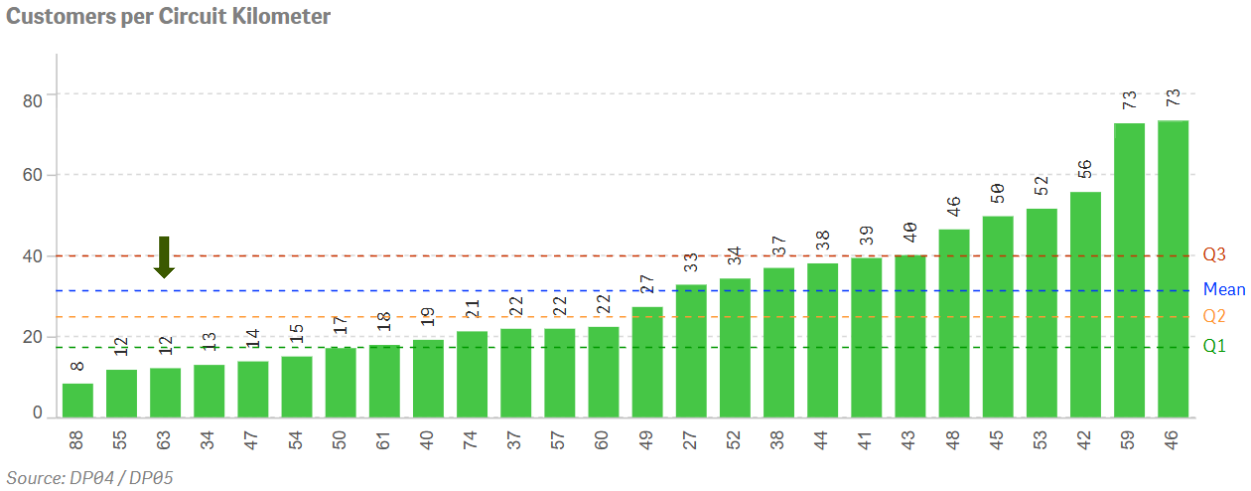
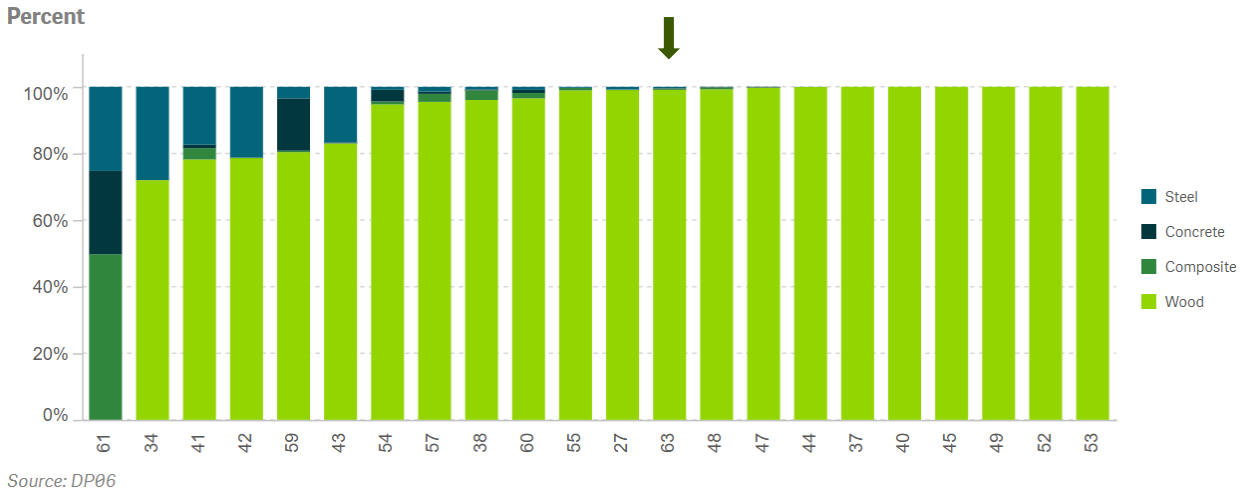


Figure 5 presents distribution poles by material type. Similar to most utilities in the comparison group, Hydro One's distribution poles are mainly wood, thus ensuring comparability with respect to pole type.

Figure 5. Distribution Primary and Secondary Poles by Material Type



3.1.2 Distribution Substations

Similar to the number of customers per distribution circuit kilometer, Figure 6 indicates the number of Hydro One transformers installed per 100 kilometers is among the lowest in the comparison group. The low number of transformers per 100 kilometers is consistent with the observation that Hydro One distribution substations are equipped with fewer transformers than the comparison group – most Hydro One distribution substations contain one power transformer (or one set of 3 single-phase devices) , whereas, based on Guidehouse's experience working

with utilities in the comparison group, some utilities operate substations with up to four transformers.

Figure 6. Substation Transformers per 100 Kilometers of Distribution Circuits

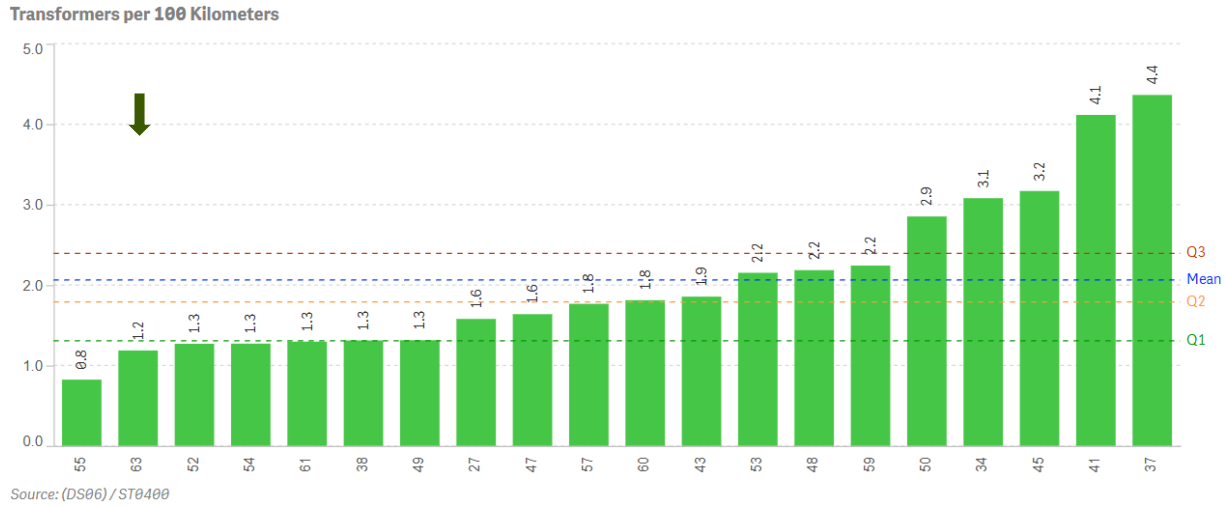
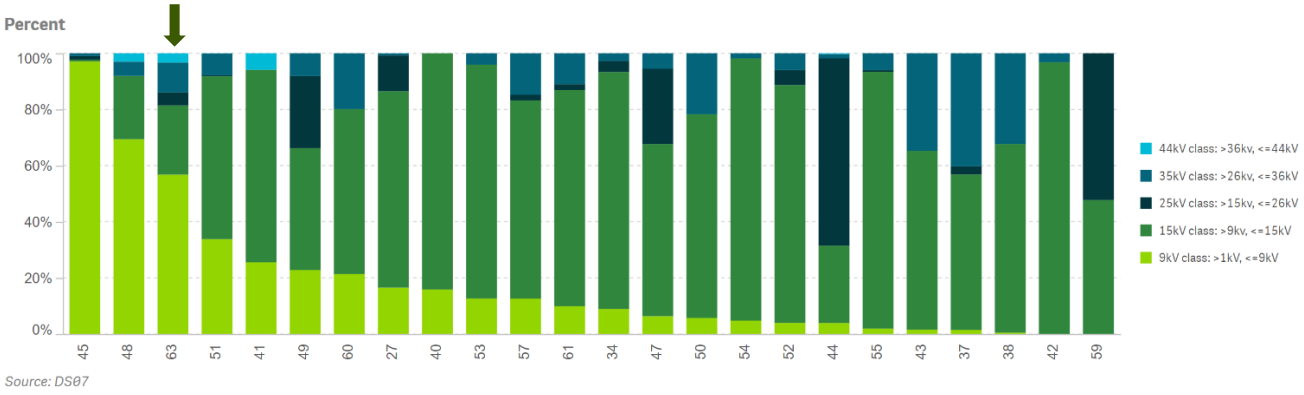


Figure 7 presents secondary voltages of Hydro One's transformers to those of the comparison group. Most transformers in the comparison group are 15kV class (e.g., 12,47kV). In contrast, the majority of Hydro One transformers are rated 9 kV and below, which typically are lower rated devices in terms of MVA capacity.

Figure 7. Substation Transformer Banks by Voltage (Secondary)



3.2 Asset Management Practices

3.2.1 Distribution Poles

The study investigated asset management practices utilized by the comparison group for wood poles. These include inspections and testing intervals for wood poles and crews utilized for pole installations.

Hydro One conducts visual patrols of distribution poles every six years for rural feeders and every 3 years for urban feeders (as required by provincial regulations[2]), which is more frequent than the comparison group average of 10 years. Figure 8 summarizes the range of inspection and testing practices for the comparison group, which indicates that several utilities reported 10-year cycles for all inspection activities, including pole boring and excavation; whereas Hydro One conducts these tests every 15 years.

Figure 8. Distribution Pole Inspection Cycle Intervals (Years)[3]

	27	34	37	38	40	41	42	43	44	45	48	49	50	52	54	55	57	59	60	61	63	74	88
Visual	5	2	10	8	10	3	10	18	10	10	10	10	10	10	10	10	10	10	10	10	6	-	-
Patrol	1	1	10	*	-	3	10	18	-	-	10	-	10	-	-	-	-	-	-	-	6	3	2.3
Ultrasonic	10	-	-	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excavation	10	65	10	8	10	-	10	18	10	10	10	10	-	10	10	10	10	10	10	10	15	-	-
Sound	10	2	10	8	10	-	10	18	10	10	10	10	-	10	10	10	10	10	10	10	15	-	-
Bore	10	65	10	8	10	-	10	18	10	10	10	10	-	10	10	10	10	10	10	10	15	-	-
Other	-	-	-	-	-	-	-	18	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-

Source: DP08

3.2.2 Distribution Substations

The study investigated asset management practices utilized by the comparison group for substation equipment. These include inspections and testing practices for substation equipment and average transformer loadings.

Figure 9 indicates Hydro One applies a range of approaches for planned inspections of substation equipment, with time-based serving as the primary approach, closely followed by a condition-based approach. Hydro One's practice is broadly comparable to the practices observed at other utilities.

[2] In addition to poles, the 6-year inspections include a visual assessment of all equipment and devices located on or attached to distribution poles.

[3] Utility 34 conducts excavation and bore testing at the end of their poles' expected service life of 65 years. The asterisk (*) for Utility 38 denotes that they conduct patrols on an as needed basis.

Figure 9. Distribution Substation Inspection and Testing Intervals

What approach do you use for planned inspection programs for the following substation components?

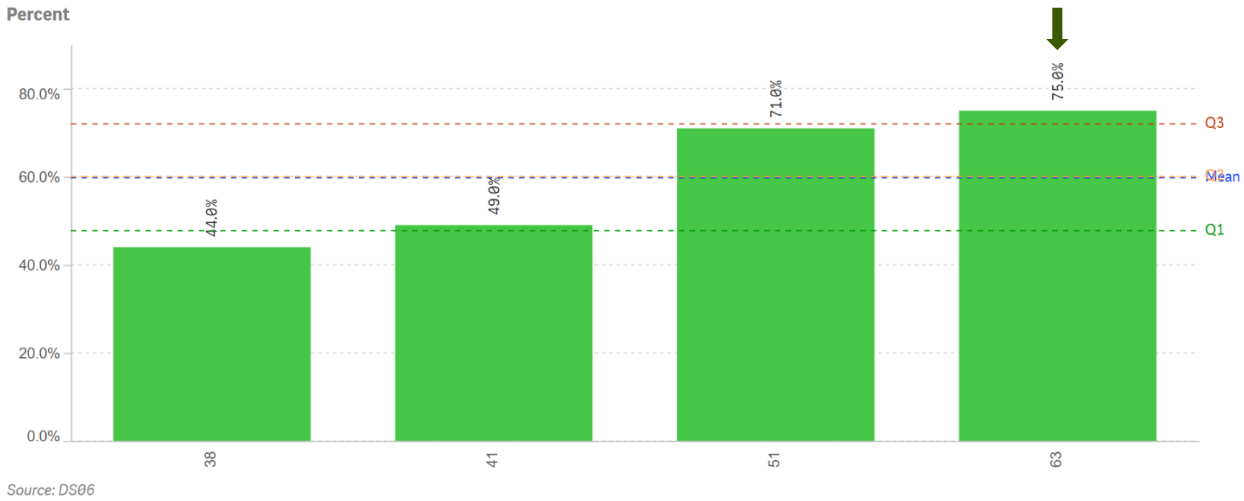
1 = Reliability-Centered
2 = Time-Based
3 = Condition-Based
4 = Ops Count-Based
5 = Manufacture Rec
6 = Data Analytics
7 = Risk Models
99 = Other Approach

	34	37	38	39	40	41	44	45	48	49	50	52	53	63
Power Transformers	3,6	3	2	2	2	1, 2, 3, 5, 6	1,2,3,5	-	2	2	2	2	-	2,3,4
Switchgear	2	3	2	2	2	3	1,2,3,5	-	2	99	2	99	99	2
Circuit Breakers	3	3	2,4	2	2	1, 2, 3, 5, 6	1,2,3,5	-	2	99	2	99	99	2,3
Relays	2	3	2	2	2	1,2,3,5	-	2	2	-	2	-	-	2
Reclosers	2,3	3	-	2	2	1, 2, 5	-	2	-	99	-	99	99	2,3,4,5

Source: DS09

Hydro One substation transformer loading data indicates its transformers, on average, are heavily utilized based on nameplate capacity. Figure 10 shows average loadings of 75 percent at peak, which is above the comparison group mean of 59.7 percent, and above each of the other utilities that provided loading data.

Figure 10. Hydro One Substation Transformer Loading at Peak

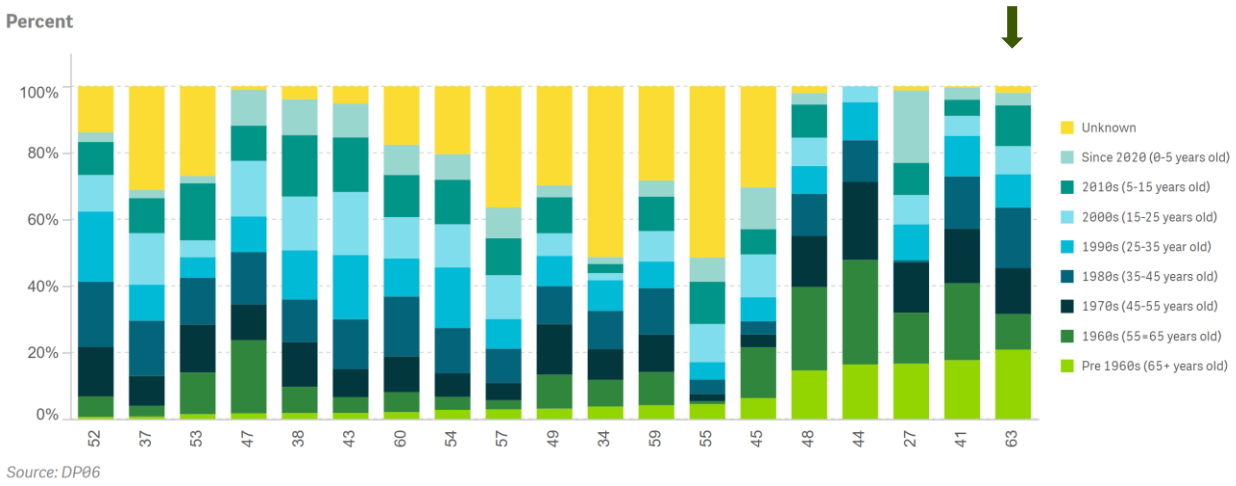


3.3 Replacement Practices

3.3.1 Distribution Poles

Figure 11 presents the distribution of poles installed by decade for Hydro One and the comparison group. Results indicate that Hydro One has the largest percentage of poles installed pre-1960's as well as smaller but significant percentages installed in the 1960's and 1970's.

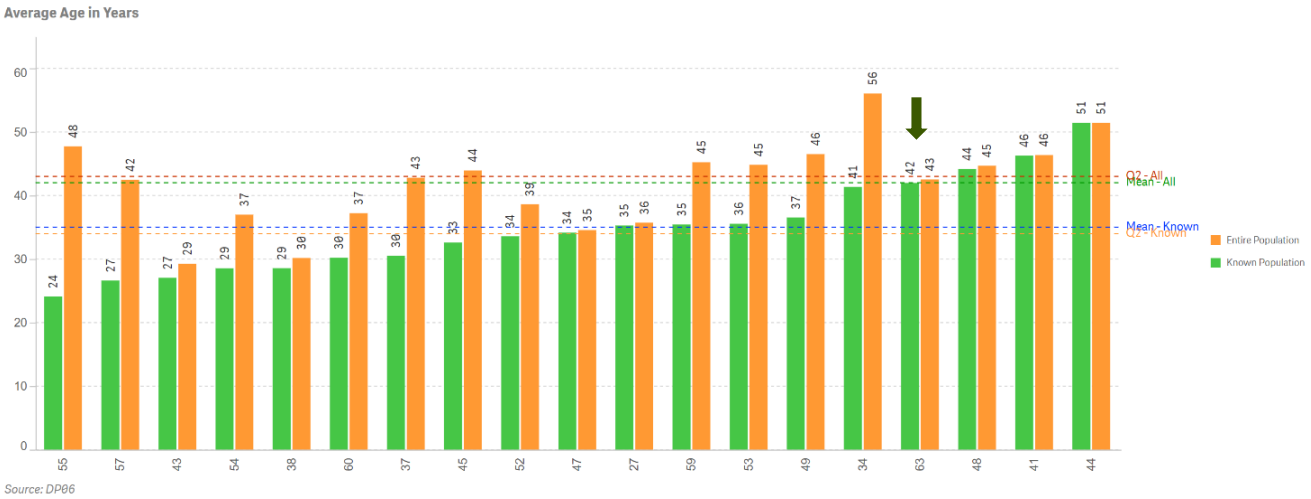
Figure 11. Percent of Distribution of Wood Poles Installed per Decade



The yellow portion of the chart above represents the percentage of the pole population for which the installation date is unknown. These poles are often, though not exclusively, among the oldest assets on the system, as historical records may not have been consistently maintained. Additional factors contributing to unknown pole ages may include utility mergers or acquisitions, incomplete asset transfers between predecessor companies, loss or deterioration of historical paper records, replacement or removal of pole tags or stamps, legacy recordkeeping practices that predated modern asset management systems, undocumented field replacements performed during emergency restoration activities, and discrepancies arising from system mapping or GIS conversions. As a result, portions of the pole population may lack verifiable installation date information despite ongoing asset management and inspection efforts.

Figure 12 presents two views of the average age of distribution poles for Hydro One relative to the comparison group. The "Entire Population" view (orange bars) assumes poles with unknown installation dates are among the oldest, resulting in a higher average age—approximately 42 years for the comparison group and 43 years for Hydro One. The "Known Population" view (green bars) excludes poles with unknown ages, yielding lower averages of approximately 33 years for the comparison group and 42 years for Hydro One.

Figure 12. Average Age of Distribution Wood Poles



Source: DP06

Figure 13 indicates the priority (ranked 1 to 5, with 5 being highest priority) used for determining pole replacements by the comparison group. Hydro One pole replacement practices are primarily driven by condition rather than age, in line with the comparison group. While many pre-1960 poles exceed their expected service life, they are not automatically replaced unless inspections indicate their condition no longer meets acceptable remaining life criteria.

Figure 13. Priority Ranking for Pole Replacements

	27	34	37	38	40	41	42	43	45	46	47	48	63
Other	5	-	-	3	-	-	-	-	-	2	5	-	-
Number of Customers Impacted	-	5	4	-	-	2	-	2	3	3	-	-	4
Age of Pole	-	1	1	-	-	4	-	5	4	4	-	5	1
Pole Condition	-	5	5	5	5	5	5	5	5	5	-	-	5
Impact on Critical Customers	-	5	3	-	-	3	-	3	4	1	-	-	3
Execution Efficiency (Proximity to Other Poles)	-	5	2	4	-	1	-	2	3	2	-	-	2

Source: DP25

Figure 14 indicates the expected service life of Hydro One's wood pole structures at 62 years, which is above the 51-year average of the comparison group by 11 years.

Figure 14. Expected Service Life of Distribution Wood Poles

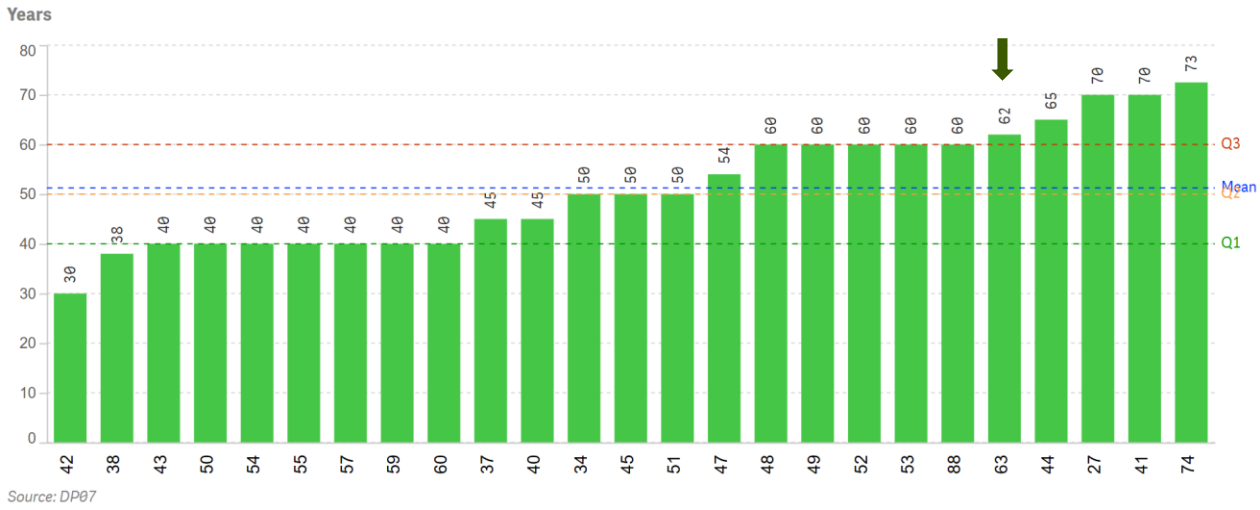


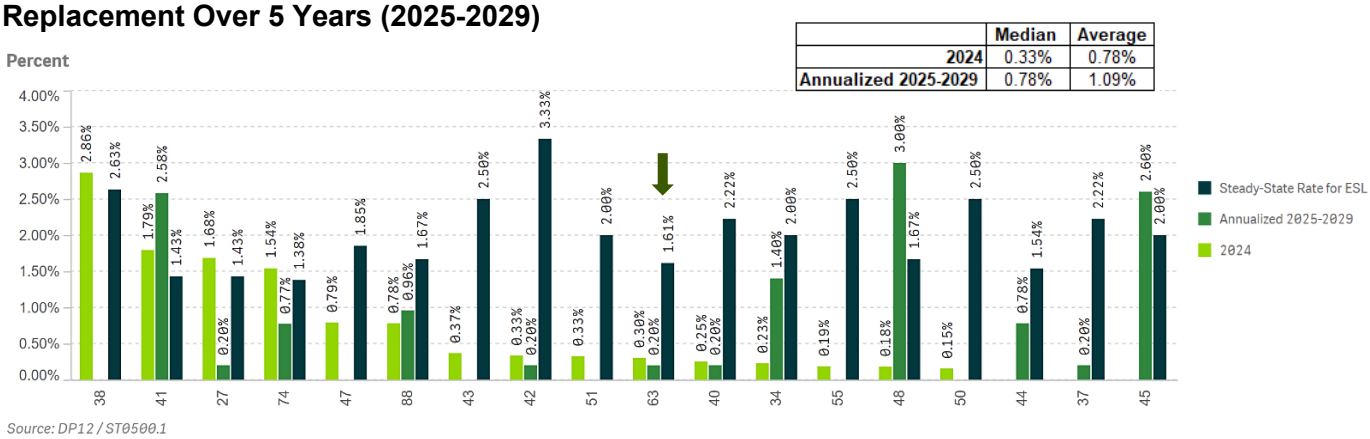
Figure 15 compares the annualized percentage of distribution poles Hydro One replaced in 2024 and planned over the next five years from 2025 to 2029. Hydro One's annual pole replacement rate for exclusively planned activities in 2024 was 0.3 percent, which was marginally below the median of the comparison group. Planned replacement activities for the entire comparison group include asset replacements scheduled in advance through the utilities maintenance or capital planning process to address asset condition, life expectancy, or system improvement needs and are performed before failure occurs.

The annual rate for planned or expected replacements over the next 5 years (2025-2029) for Hydro One is projected to be 0.2 percent, which is lower than the comparison group median of 0.78 percent. Expected replacement activities include every instance where an asset is replaced, regardless of whether the work was planned or unplanned, with unplanned activities including emergent replacements (equipment failure, storm damage, vehicle pole strikes, emergency reliability issues, safety hazards, emergent field conditions, and more)

Figure 15 also compares each utility's actual pole replacement rates to steady-state rates required to align the pole fleet with its expected service life. The steady-state rate (shown as dark blue bars) is calculated as the inverse of the expected service life (i.e., 1 divided by the service life in years). The chart indicates that Hydro One's current replacement rates—similar to many utilities in the comparison group—fall below the steady-state rate or the level required to maintain the pole fleet within its expected service life.

It is important to note that replacement pacing across utilities is not uniform or linear over time. Annual replacement rates may fluctuate due to differences in asset management strategies, system demographics, and capital planning priorities.

Figure 15. Distribution Wood Pole Replaced Annually in 2024, Planned or Expected Replacement Over 5 Years (2025-2029)

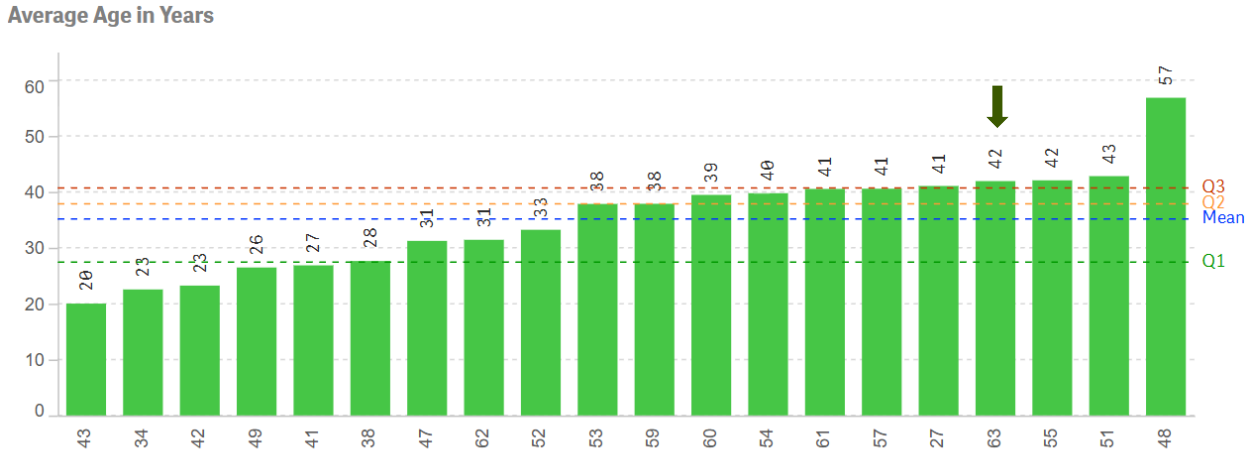


Source: DP12 / ST0500.1

3.3.2 Substation Transformers

Figure 16 presents the average age of Hydro One distribution substation transformers versus those of the comparison group. The average age of Hydro One 's transformers is 42 years, which is above the average age of 35 years for the comparison group.

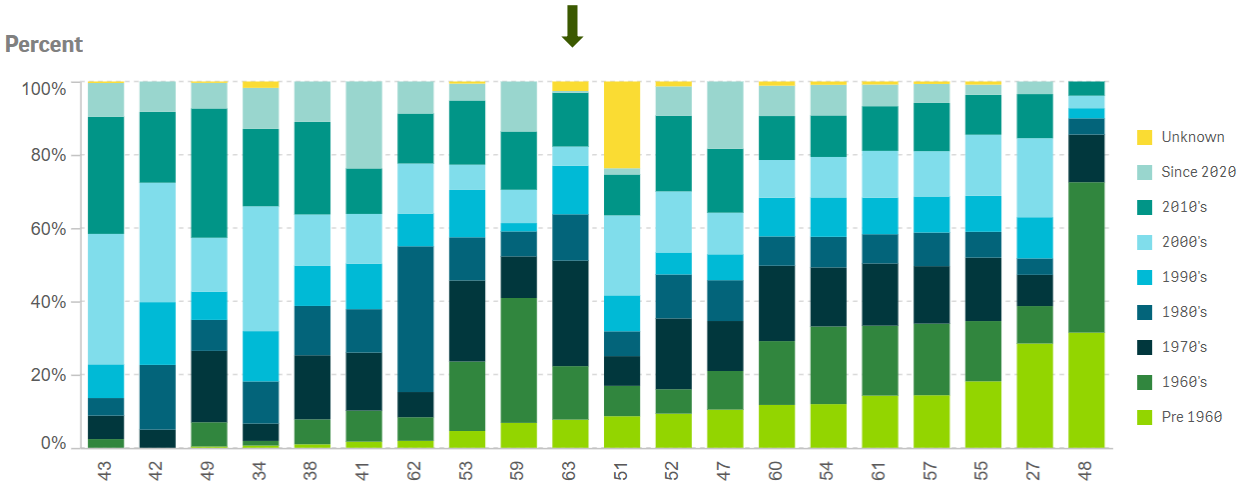
Figure 16. Average Age of Substation Transformers



Source: DS08

Figure 17 presents the range of substation transformer ages by decade for Hydro One to the comparison group. Hydro One transformer age is distributed somewhat equally across each decade, with the largest percentage in the 1970's.

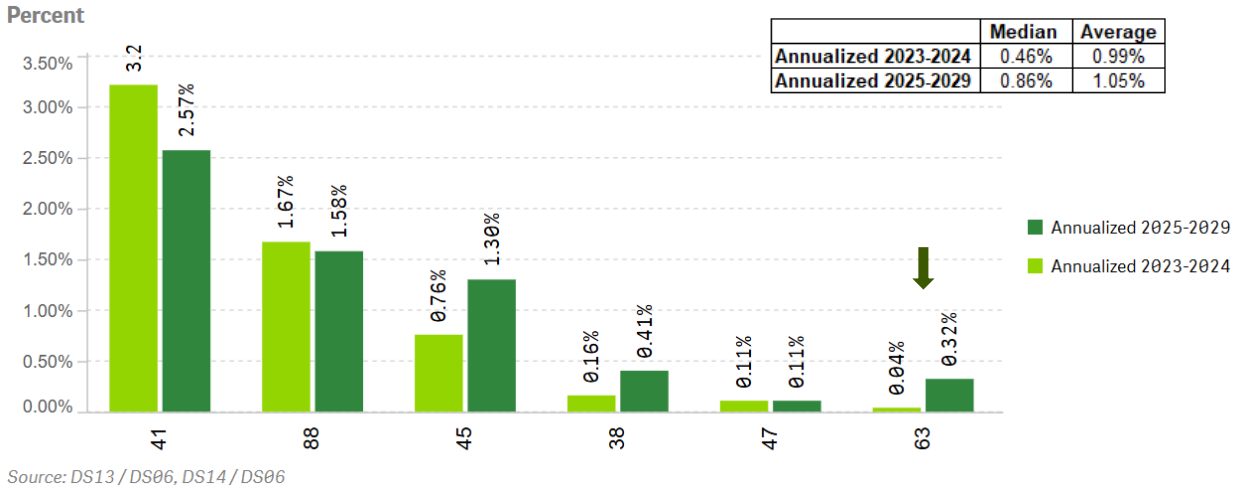
Figure 17. Age of Substation Transformers by Decade



Source: DS08

Figure 18 compares Hydro One's substation transformer annualized replacement rates for 2023-2024, as well as planned rates for 2025–2029, against those of the comparison group. Hydro One completed a single replacement project in the 2023-2024 period, and overall replacement rates remain below the comparison group median among utilities reporting data. Figure 18 only represents transformer replacements based on asset condition and does not reflect investments related to load growth or system expansion.

Figure 18. Transformers Replaced Annually in 2023-2024 and Planned Over Five Years (2025- 2029)



	Median	Average
Annualized 2023-2024	0.46%	0.99%
Annualized 2025-2029	0.86%	1.05%

Source: DS13 / DS06, DS14 / DS06

Hydro One Networks Inc.

AMI 2.0 Project Execution Process Review

Submitted by

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September 2026

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List of Abbreviations	
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
BRD	Business Requirements Document
CAD	Canadian Dollar
CDM	Capital Delivery Model (H1 term)
CMEP	California Metering Exchange Protocol
DI	Distributed Intelligence
DIDA	Distributed Intelligence Distributed Automation
E Source	E Source Companies LLC
ETC	Estimate to Complete
HES	Head End System
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IR	Interrogatory Responses
ISD	Investment summary document
IT	Information Technology
JRAP	Joint Rate Application Plan
MDM/R	Meter Data Management / Repository
MDMS	Meter Data Management System
O&M	Operations and Maintenance
PDM	Project Delivery Model (H1 term)
PM	Project Management
PMO	Project Management Office
RAID	Risk, Assumptions, Issues, and Dependencies
RTM	Requirements Traceability Matrix
SAP	SAP SE Company
SME	Subject Matter Expert
SOW	Statement of Work

EXECUTIVE SUMMARY

Hydro One Networks Inc. (HONI) is replacing its original Advanced Metering Infrastructure (AMI) system with a next-generation AMI 2.0 solution that includes deployment of meters, communications infrastructure, and supporting enterprise systems.

Large-scale AMI replacement programs are complex, multi-year initiatives involving the coordinated deployment and integration of field devices, communications networks, enterprise software systems, operational processes, and customer-facing capabilities across the utility enterprise. These programs commonly encounter evolving requirements, systems integration challenges, resource constraints, deployment adjustments, and increased testing and defect remediation efforts as implementation progresses. As a result, evaluation of AMI program execution requires consideration of utility-specific operating conditions, regulatory requirements, technology maturity, and overall program scope in addition to traditional cost and schedule metrics.

HONI engaged E Source Companies LLC (E Source) to conduct an independent review of the AMI 2.0 project execution process to evaluate whether execution to date is reasonable and justifiable relative to the established Project Baseline, similar industry programs, and the organization's evolving operational and technical requirements.

The review included the evaluation of:

- Program governance and project management approach
- Project scope and scope evolution
- Budget performance and Estimate to Complete (ETC)
- Schedule performance and execution management
- Systems integration and deployment execution

E Source's review was conducted through a structured approach that included document review, stakeholder interviews, and a market scan of other North American utility AMI deployments. The review included assessment of project governance, execution management, budget and schedule performance, deployment strategy, systems integration activities, vendor oversight, and key execution challenges encountered throughout the program lifecycle.

The review also evaluated whether the increased costs reflected in the current ETC are supported by identified changes in scope, execution realities, solution maturity considerations, operational requirements, and implementation complexities commonly associated with large-scale next-generation AMI programs.

Based on the information reviewed, E Source found that HONI's governance and project management framework for the AMI 2.0 program is reasonable and appropriately structured for a program of this scale and complexity. The project is supported by formal governance structures, project controls, vendor oversight mechanisms, risk and issue management processes, and performance tracking practices aligned with the original Joint Rate Application (JRAP) plan filings and Project Baseline.

The review found that many of the challenges encountered during execution are consistent with industry experience for large-scale AMI replacement programs, particularly those involving significant systems integration, evolving solution maturity, operational transformation, and utility-specific regulatory requirements. Key challenges with respect to the project's execution to date included:

- Greater-than-anticipated systems integration complexity
- Ontario-specific California Metering Exchange Protocol (CMEP) and data synchronization requirements
- Vendor solution readiness and scaling limitations
- Increased field deployment and labor costs
- Expanded testing and defect remediation efforts
- Resource constraints associated with concurrent initiatives and specialized expertise requirements
- Additional infrastructure and operational realities identified during deployment activities

E Source found that HONI identified, escalated, and responded to these challenges through a structured project governance and various mitigation strategies, including phased contracting, parallel execution of workstreams, deployment planning adjustments, automation, defect prioritization, and targeted resource management activities.

The review also found that the evolution of project scope remains substantially aligned with the program's original strategic objectives, including replacement of end-of-life AMI infrastructure and enablement of broader grid modernization capabilities. Incremental scope growth observed during execution was primarily associated with integration requirements, operational readiness considerations, execution realities, and intentional investments in Distributed Intelligence (DI).

From a budget perspective, E Source found that the increases reflected in the current ETC are supported by identified and explainable cost drivers consistent with industry experience for AMI programs of similar scale and complexity. However, a degree of meter deployment execution risk remains as annual meter deployment volumes have yet to be demonstrated in practice. While HONI's forecasted capital cost per meter is modestly above the market scan group average, the review determined that the variance is directionally reasonable when considering differences in meter density, regulatory requirements, operating environment, labor conditions, solution architecture, and overall program scope.

Similarly, although the program experienced contract execution delays during early implementation phases, E Source found that HONI maintained overall schedule control through mitigation planning, phased execution strategies, and concurrent execution activities. While the forecasted completion date is approximately one year later than the original Project Baseline, the updated program timeline remains reasonable given the challenges associated with contracting, systems integration, testing, deployment readiness, and external factors.

The market scan further demonstrated that many utilities in the market scan group experienced similar challenges related to systems integration, meter deployment logistics, regulatory requirements, workforce constraints, evolving AMI functionality expectations, and maturity of

solution. As such, the execution challenges encountered by HONI are not unique within the context of next-generation AMI modernization programs.

Overall, E Source concludes that HONI's AMI 2.0 project execution, including its governance structure, management approach, scope evolution, budget adjustments, and schedule management, remains reasonable when evaluated against similar industry programs and the complexity inherent in large-scale AMI modernization initiatives.

SECTION I – INTRODUCTION

Hydro One Networks Inc. (HONI) initiated this process review to evaluate the execution and performance of its Advanced Metering Infrastructure (AMI) 2.0 program, which replaces the original AMI system with a next-generation solution that includes advanced use cases, meters, communications infrastructure, and supporting enterprise systems. The review assesses whether HONI's AMI 2.0 execution to date is reasonable relative to the established Project Baseline, similar industry programs, and the evolving operational and technical requirements identified throughout implementation. This review was not intended to be a financial audit.

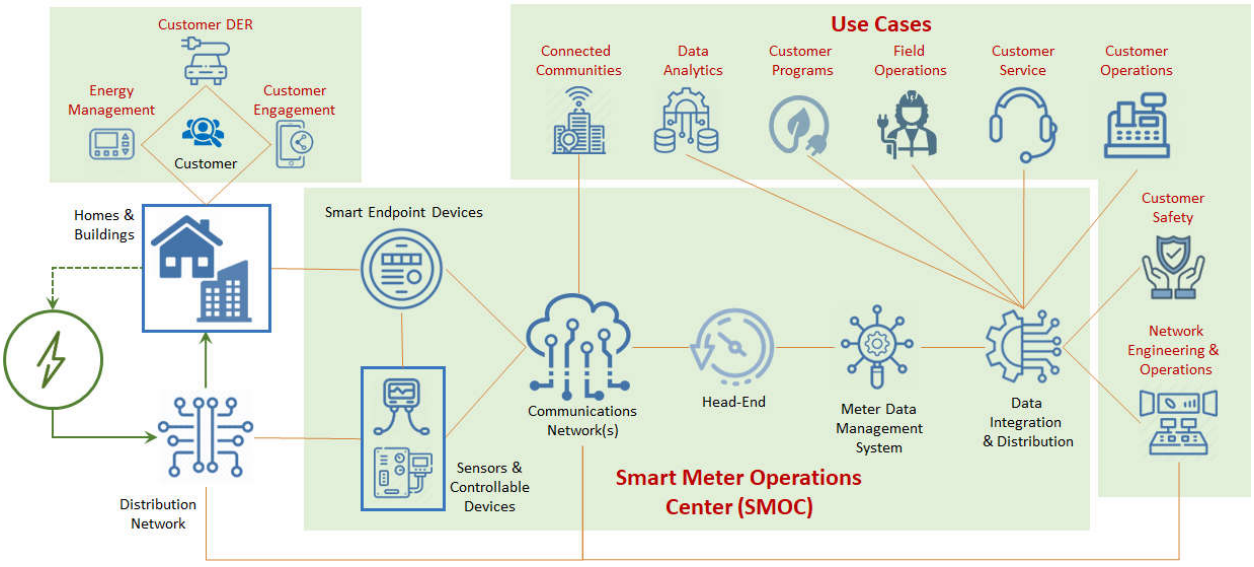
AMI Overview

AMI 2.0 programs inherently have a broader reach across the business and are not only required to integrate next generation meters, communications networks, enterprise applications, and supporting analytics and data platforms, but also are required to implement new and updated operational people and process capabilities. AMI 2.0 targets enhanced or expanded areas of opportunity to further improve operational efficiency, customer service, reliability, and future grid modernization capabilities. Key components of a modern AMI ecosystem include:

- Broader AMI-enabled functionality: AMI 2.0 supports an expanded set of customer, operational, asset management, and grid modernization use cases beyond traditional meter-to-cash capabilities.
- Greater organizational impact: expanded functionality requires updated business processes, operating models, and skill sets across customer, field, information technology (IT), operations, and analytics teams.
- Advanced meters and communications: new meters and communications networks provide enhanced data, alarms, outage capabilities, remote operations, grid edge computing, and support for broader distribution automation capabilities.
- Modern system architecture: AMI 2.0 requires more integrated enterprise systems including upgraded head end systems, meter data management system (MDMS) capabilities, analytics platforms, data warehouses, and more dynamic integration with upstream and downstream systems.

Together, these components form the interconnected next generation AMI ecosystem illustrated in Figure 1.

Figure 1: Next Generation AMI Strategic Architecture



Complexity of Large-Scale AMI Programs

Large-scale AMI programs are complex, multi-year initiatives involving the coordinated deployment of field devices, communications networks, enterprise software systems, systems integration, operational processes, and customer-facing capabilities across the utility enterprise.

AMI replacement programs are particularly complex because utilities must maintain ongoing meter operations, billing accuracy, customer service, and regulatory compliance while simultaneously implementing and integrating next-generation technologies and processes. Utilities transitioning from AMI 1.0 to AMI 2.0 often require coexistence between legacy and new platforms, migration of operational processes and data, expanded systems integration and testing activities, and phased deployment strategies designed to minimize operational and customer impacts. By comparison, utilities deploying AMI for the first time may face significant implementation challenges but are generally not required to manage the same level of legacy system transition and operational continuity complexity. Given AMI 2.0 programs broaden the reach of these programs with improved AMI data and functionality being used more widely across the business, it follows that complexity increases also via the introduction of a new set of stakeholders to engage.

Project complexity is further influenced by utility-specific operating conditions, including service territory characteristics, meter density, labor environment, regulatory obligations, communications architecture, and solution maturity. In Ontario, additional considerations such as California Metering Exchange Protocol (CMEP) requirements and synchronization with provincial market processes introduce further implementation and testing complexity.

Industry experience indicates that AMI programs frequently require adjustments to deployment strategies, systems integration approaches, testing activities, and operational processes as implementation progresses. As a result, a market scan of AMI programs must consider

differences in scope, operating environment, and strategic objectives in addition to cost and schedule outcomes.

Objective

This review evaluates HONI's AMI 2.0 program execution relative to the Project Baseline and a group of other North American AMI programs. The review assesses whether HONI's governance structure, project management approach, budget performance, schedule management, and scope evolution remain reasonable relative to the complexity and execution realities associated with large-scale AMI deployments.

The review was conducted in four phases:

- Project kickoff, and initial data request
- Establishment of the Project Baseline
- Targeted stakeholder interviews and development of findings
- Market Scan

The review evaluates HONI's implementation of a next-generation AMI solution, including deployment of advanced metering infrastructure, communications systems, supporting enterprise integrations, and associated operational transformation activities. The assessment includes the review of the following:

- Project objectives and governance
- Scope management and scope evolution
- Budget performance and Estimate to Complete (ETC)[1]
- Schedule performance and mitigation activities
- Systems integration and deployment execution
- Vendor oversight and operational readiness activities
- Performance relative to a group of other North American AMI programs

The market scan assesses deployment timelines and capital cost metrics across a group of other North American utilities relative to HONI, while acknowledging differences in operating environments, project elements, and execution challenges.

[1] The ETC assessed as part of this review is the September 2025 estimate.

SECTION II – APPROACH

E Source Companies LLC (E Source) conducted a structured review of HONI's AMI 2.0 program to evaluate project execution relative to the Project Baseline, similar industry programs, and the execution realities associated with large-scale AMI deployments. The review combined document review, stakeholder interviews, and a market scan to assess governance, scope management, budget performance, schedule management, systems integration activities, and overall program execution.

To support the review, E Source first established a Project Baseline aligned with the original regulatory forecasts, estimates, approved program objectives, and supporting project documentation. Establishing this Project Baseline provided the reference point necessary to evaluate how the AMI 2.0 program has evolved throughout execution relative to the original program assumptions and expectations.

E Source then evaluated the current state of program execution through documentation review, targeted stakeholder interviews, and assessment of current project performance, governance, scope, budget, schedule, and operational execution activities. This current execution "snapshot" was subsequently considered against a group of utility AMI programs from the market scan to provide industry context regarding implementation complexity, deployment timelines, cost performance, and common execution challenges associated with large-scale AMI modernization initiatives.

The review was conducted in four phases:

- Project kick-off and data collection
- Documentation review and establishment of the Project Baseline
- Targeted stakeholder interviews and development of findings
- Market Scan

The following sections describe the key elements of the review methodology.

Project Kick-Off and Data Collection

E Source initiated the review and developed an initial data request to assess the project's governance structure and to support the establishment of the Project Baseline.

The initial data request included:

1. Project charter, project execution plan, and business case
2. Summary of scopes and statements of work (SOWs), including amendments and change requests
3. Organization charts and staffing information for project personnel, sponsors, and stakeholders
4. Project management office (PMO) schedule, methodology, standards, stage gates, and review procedures

5. Project deliverables including requirements documentation, design documents, test plans, test results, risk, assumptions, issues, and dependencies (RAID) logs, and status reports
6. Pilot deployment results and lessons learned, including cost data supporting the current ETC
7. Relevant regulatory materials including pre-filed evidence, interrogatories, and associated responses
8. Service area and deployment demographic information
9. Systems integration requirements and solutions architecture documentation

Documentation Review and Establishment of the Project Baseline

E Source reviewed thirty-seven documents to support the assessment of the program's governance and to develop a comprehensive Project Baseline for the AMI 2.0 program. E Source reviewed these materials against a Project Management (PM) checklist to determine whether the project's governance and management framework are reasonable and appropriate for an AMI program of this scale (see Table 1).

Table 1: Project Management Checklist and Document Review

Project Management Checklist Components	Description	HONI Document(s) that satisfy PM Checklist Component
Project Initiation, Governance, & Organization	a. Define project objectives and scope. b. Identify stakeholders and establish roles. c. Develop a project charter outlining responsibilities.	✓ Project execution plan
Project Management Framework	a. Create a comprehensive project management plan. b. Detail roles, responsibilities, and communication strategies. c. Establish a change management process.	✓ Project charter ✓ PMO process and procedures ✓ CDM mapping to the PDM
Planning & Scheduling	a. Provide initial project timeline and milestones. b. Outline resource allocation and responsibility assignments. c. Develop a schedule management plan.	✓ Integrated project plan framework (basis of schedule) ✓ Integrated project plan
Scope & Change Management	a. Summarize vendor roles and contract obligations. b. Establish processes for scope changes. c. Include governance structures for managing changes.	✓ PMO process and procedures
Vendor & Contract Management	a. Identify contracting processes and requirements. b. Manage relationships with vendors and stakeholders. c. Monitor performance and compliance with project standards.	✓ PMO process and procedures
Resource & Staffing Model	a. Define staffing levels and skill sets by phase. b. Establish roles and commitments with internal vs. external resources. c. Outline assumptions and training/ onboarding requirements.	✓ Organizational Structure

Project Management Checklist Components	Description	HONI Document(s) that satisfy PM Checklist Component
Execution / Implementation	a. Identify business needs and objectives. b. Develop requirements traceability matrix (RTM). c. Monitor progress and ensure alignment with initial goals.	✓ BRDs/RTM ✓ Field deployment strategy
Monitoring and controlling	a. Track performance using KPIs and benchmarks. b. Manage change requests and impacts on project scope. c. Report on performance and corrective actions.	✓ Architecture book of record ✓ Architecture releases
Risk, Issue, and Decision Management	a. Identify potential risks and mitigation strategies. b. Document and prioritize risks and issues. c. Regularly review and adjust risk management plans.	✓ PMO process and procedures
Regulatory Requirements	a. Adhere to relevant laws and regulations. b. Manage business case updates and reporting. c. Ensure compliance documentation is complete and accessible.	✓ JRAP ISD and IR Responses ✓ JRAP settlement proposal ✓ Business Cases (Partial Approvals)
Community Engagement	a. Foster relationship building with community stakeholders. b. Regularly communicate project developments. c. Engage in discussions to address concerns and feedback.	✓ PMO process and procedures

The document review also informed the AMI 2.0 Project Baseline, using HONI's Joint Rate Application (JRAP) plan filings as the reference point to compare to the actual project execution. Documentation reviewed included the project execution plan, project charter, integrated project plans, integration requirements, solution architecture materials, project deliverables, and regulatory filings.

The Project Baseline established the framework used to evaluate current program execution and included assessment of:

- Project plans and schedules
- Governance structures and stakeholder engagement models
- Risk, issue, and change management processes
- Status reporting and performance tracking practices
- Vendor and contract management strategies
- Staffing models and resource management plans
- Systems integration and deployment planning approaches

Target Interviews and Findings

E Source conducted subject matter expert (SME) interviews with HONI personnel to assess how the AMI 2.0 program has been managed and executed in practice relative to the Project Baseline.

Interview discussions focused on:

- Project leadership and functional responsibilities
- Program governance and decision-making processes
- Scope management and deployment planning
- Project workflow and operational coordination
- Systems integration and testing activities
- Performance tracking and reporting practices
- Resource planning and staffing strategies
- Contractor and vendor management
- Risk, issue, and mitigation management
- Program execution cadence and operational readiness

Market Scan

E Source considered HONI's AMI 2.0 program relative to other utility AMI initiatives to provide context regarding project scope, execution approach, budget performance, deployment timelines, and common implementation challenges observed across the industry.

Because relatively few utilities have implemented AMI 2.0 programs at HONI's scale and complexity, the market scan emphasized qualitative findings supplemented by quantitative reference points where sufficient public information was available. The scan considered:

- Capital cost performance
- Deployment schedule and pace
- Governance and project management approaches
- Systems integration and operational complexity
- Deployment strategy and execution considerations
- Program scope and functionality

Given the variability across AMI programs, including differences in operating environment, regulatory requirements, technology architecture, deployment strategy, labor structure, and cost accounting methodologies, the scan intended to provide directional comparison rather than direct one-to-one benchmarking. As a result, the scan focused on understanding and explaining key drivers that influence observed differences between utilities, including operating context, implementation approach, tradeoffs, and constraints.

The market scan focused on:

- HONI's capital cost per meter relative to the market scan group of utilities
- HONI's deployment timeline relative to the market scan group of utilities
- Common execution challenges and mitigation approaches observed across the group of market scan utilities' programs

To select utilities for the market scan group, E Source applied the following criteria:

- AMI deployments completed in 2015 or later
- AMI initiatives with relevant program characteristics in common with HONI
- Publicly available information related to capital spending and deployment timelines

Market scan data sources included:

- Regulatory filings and orders
- Testimony and supporting proposals
- Business cases and annual reports
- Utility websites and public communications
- Publicly available industry materials
- Certain utility interviews and discussions

SECTION III – RESULTS

The following sections present the results of E Source's review of HONI's AMI 2.0 program execution relative to the established Project Baseline and the market scan group of industry programs. The results summarize key observations, supporting evidence, and findings identified through documentation review, stakeholder interviews, and a market scan.

Because large-scale AMI programs involve highly interconnected systems, operational processes, field deployment activities, and enterprise integrations, execution challenges frequently have impacts across multiple project dimensions simultaneously. For example, systems integration complexity may influence project scope, increase implementation costs, and affect deployment schedules concurrently. As a result, several findings discussed throughout this section are relevant across scope, budget, and schedule performance categories.

The results are organized according to:

- The established Project Baseline
- The findings identified through documentation review and stakeholder interviews
- A market scan group of utility AMI programs across North America

Project Baseline

E Source established a Project Baseline for the AMI 2.0 program using HONI's JRAP filings, project documentation, regulatory materials, and supporting program information. The Project Baseline provided the reference point used to evaluate current program execution, including scope, budget, schedule, governance, and overall project performance.

The following sections summarize the Project Baseline scope, budget, and schedule established through E Source's review.

Scope

E Source determined that the AMI 2.0 Project Baseline scope aligns with HONI's JRAP filings, which predate the project initiation and includes both core AMI system replacement activities and enabling infrastructure intended to support broader strategic objectives, including customer centricity, grid modernization, electrification, customer choice, and improved reliability.

Key Project Baseline scope elements include:

- Replacement of approximately 1.4 million meters, including residential, commercial, and complex meter installations
- Support for nine meter-types, including self-contained meters
- Deployment of approximately 13,000 network equipment devices
- Procurement of software licenses and supporting environments for core AMI and head-end system functionality

- Professional services supporting project management, training, testing, optimization, and systems integration activities

The Project Baseline scope reflects both end-of-life AMI system replacement requirements and foundational investments intended to support future operational and grid modernization capabilities.

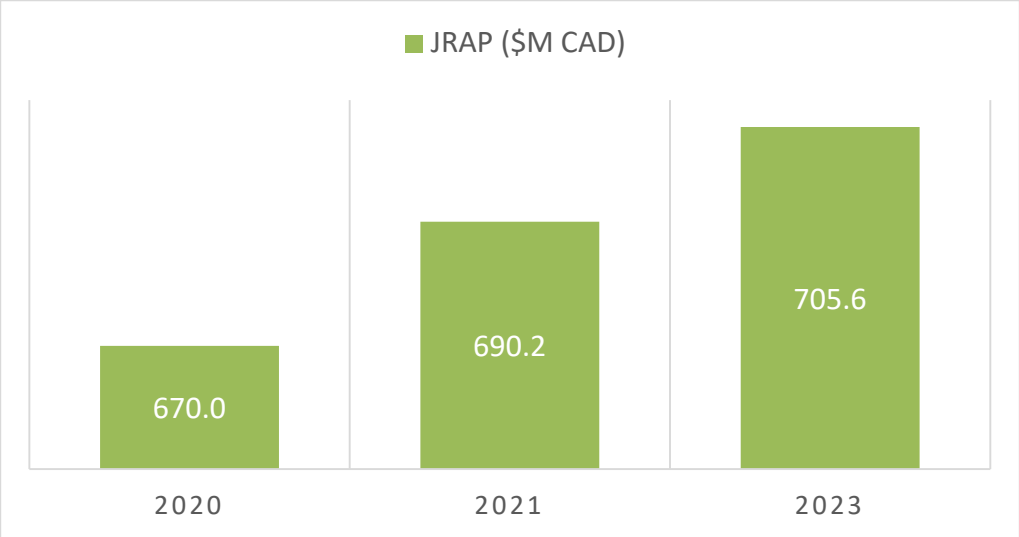
Budget

E Source determined that the AMI 2.0 Project Baseline budget aligns with HONI's JRAP filings and associated regulatory updates, including inflation adjustments incorporated throughout the program lifecycle (see Figure 2).

Key Project Baseline budget assumptions include:

- Initial project estimate of approximately $670.0 million CAD in 2020
- Inflation-adjusted estimate of approximately $690.2 million CAD in 2021
- Subsequent updated estimate of approximately $705.6 million CAD as published in the 2023 Joint Rate Application Settlement Commitment Reporting, P. 49. filed on Hydro One's external website (https://www.hydroone.com/abouthydroone/RegulatoryInformation/dxrates/Documents/HONI_JRAP_Settlement%20Commitments_20241220.pdf)
- A net project capital cost estimate range of approximately $600.0 million CAD to $847.0 million CAD, representing approximately 85% to 120% of the most recent estimate of $705.6 million

Figure 2: HONI AMI 2.0 Project Baseline Budget ($M CAD)



Schedule

E Source determined that the AMI 2.0 Project Baseline schedule aligns with HONI's JRAP filings and supporting program documentation, with program initiation beginning in 2020 and forecasted completion in 2028.

The Project Baseline schedule includes the following major phases and activities:

Phase 1: Pre-Deployment (2020-2021)

- The Pre-Development RFP Phase 1 initiated the Pre-Filing Period and focused on the competitive procurement of a new AMI 2.0 system and the establishment of a Program Management Organization.

Phase 2: Head End System (HES) Implementation and Customer Pilot (2022-2024)

- The Planning, HES, and Pilot Phase 2 of the program involved a limited amount of program planning; testing and certification of AMI 2.0 meters and network devices; the design, installation, and integrations of the HES; and the procurement of a small number of meters and network equipment to conduct and end-to-end pilot of the solution.

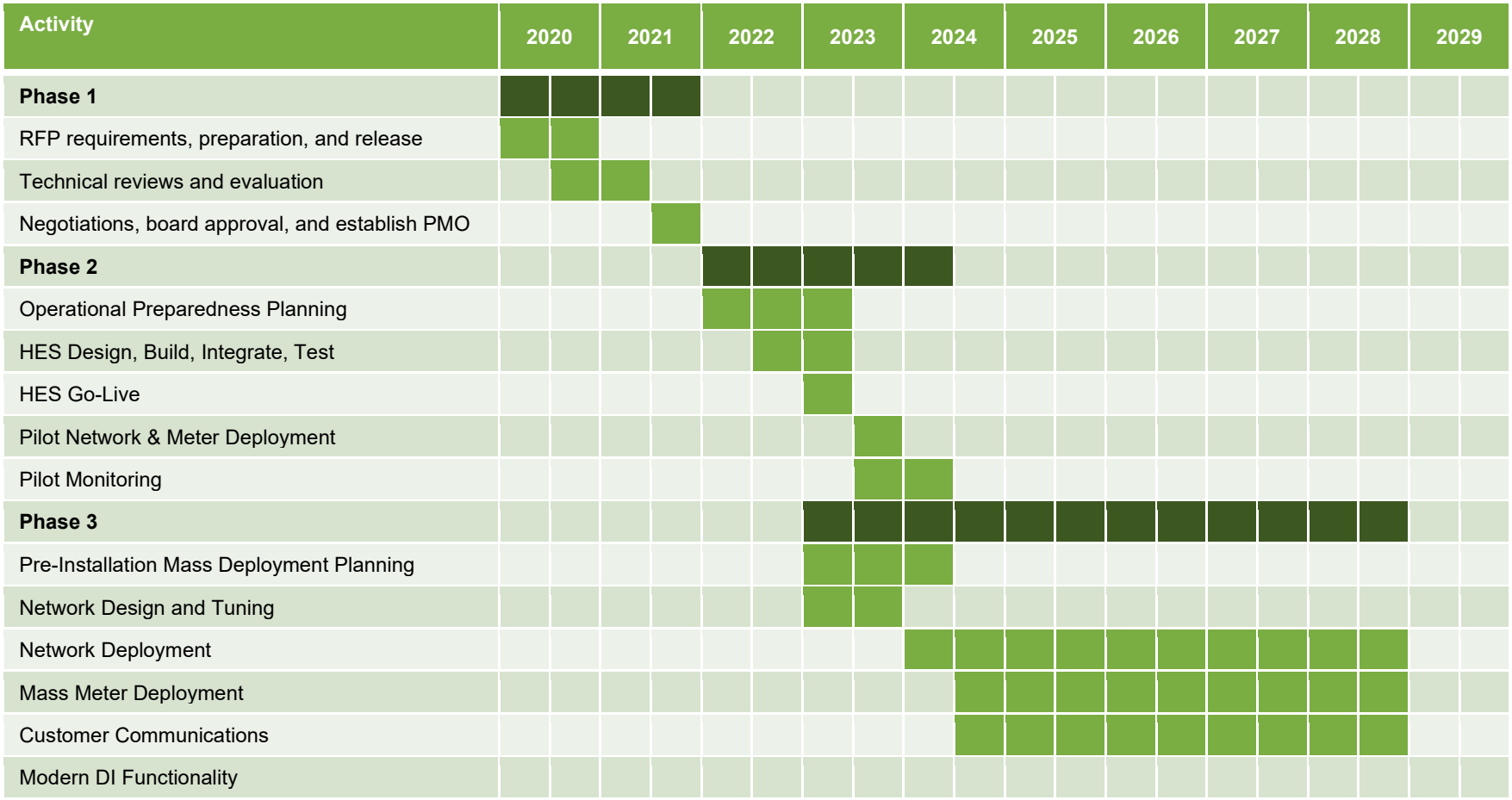
Phase 3: Mass Deployment (2023-2028)

- The Phase 3 Mass Deployment of network equipment and meters is a multipart activity involving pre-installation planning, network design activities, field deployment, and customer communications.

Expected completion (2028)

The Project Baseline schedule established a forecasted overall program completion date of 2028, as illustrated in Figure 3.

Figure 3: HONI AMI 2.0 Project Baseline Schedule



Findings Based on Documentation Review and Targeted Interviews

E Source found that HONI's governance and project management framework is appropriately structured for a program of this scale and complexity based on the review of documents compared to the PM Checklist (see Table 1). The program is supported by formal governance structures, project controls, vendor oversight mechanisms, risk and change management processes, and ongoing performance tracking practices aligned with the original JRAP filings.

Additionally, based on stakeholder interviews, supporting documentation, and review of program materials, E Source identified several principal findings that influenced project scope, budget performance, and schedule execution, when compared to the Project Baseline, as summarized in Table 2.

The review found that several execution challenges had impacts across multiple project dimensions simultaneously. For example, systems integration complexity and solution readiness considerations influenced scope evolution, increased implementation effort, and affected deployment sequencing and schedule execution. As a result, several findings discussed throughout this section are relevant across scope, budget, and schedule performance categories.

Table 2 summarizes the principal finding categories identified through the review.

Table 2: Principal Findings Categories

Finding Category	Scope	Budget	Schedule
Initial Estimate Accuracy		✓	
Contracting Delays			✓
Technology / Solution Readiness	✓		✓
Integration Complexities	✓	✓	✓
Solution Defects		✓	✓
Distributed Intelligence / Distributed Automation (DIDA)	✓	✓	
Requirement Changes	✓		
Resource Management & Transition	✓		✓
Other		✓	
Outside Factors			✓

Scope

The following findings represent the primary factors influencing scope evolution and execution complexity identified through documentation review and stakeholder interviews. The impact of these findings was typically not scope addition but increased effort to deliver the same scope due to unexpected challenges and complexities. As summarized in Table 3, the most significant scope impacts were associated with solution readiness, systems integration complexity, evolving requirements, and operational transition activities.

Table 3: HONI Project Challenges Impacting Scope

#	Finding Category	Description	Impact to Scope
1	Technology / Solution Readiness	✓ Integration of the vendor work management tool with HONI systems and processes took longer than planned. ✓ Solution shortcomings including readiness of the interface between HONI and the Independent Electricity System Operator (IESO) Meter Data Management / Repository (MDM/R) for the new AMI 2.0 solution impacted HONI's ability to scale. ✓ Some meters will not be available until 2027 and there is currently no viable drive-by meter reading solution thus forcing a less efficient work-around solution. ✓ Hardware and software data processing constraints identified when scaling led to added trouble shooting scope.	No change in scope
2	Integration Complexities	✓ Complexities stem from shortcomings in vendor systems functionality and systems integration (particularly meter-to-cash), with some functionalities not available until 2026. ✓ The vendor underestimated the Ontario specific requirements for data compilation and synchronization resulting in unanticipated integration issues which increased scope and testing and hindered HONI's deployment speed (i.e., multiple head-end systems and IESO processes). ✓ Temporary workarounds and some automations addressed immediate gaps but introduced operational inefficiencies and additional overhead. ✓ Defect prioritization is not consistent, giving rise to work on low-benefit corner cases. ✓ Overall, integrating the vendors' systems and tools into HONI's systems architecture has proven to be more challenging than anticipated.	No change in scope
3	Distributed Intelligence / Distributed Automation (DIDA)	✓ Given the exploration of DIDA functionalities as included in the scope proved positive, HONI elected to bring this scope and investment forward.	Addition to scope
4	Requirement Changes	✓ The number of requirements grew because of normal project requirements collaboration between HONI and vendors. These were predominantly an elaboration of the original RFP requirements which also impacted scope. ✓ Added complexity from the solution shortcomings have resulted in additional requirements and testing.	No change in scope
5	Resource Mgmt. & Transition	✓ Execution complexities identified during Release 2 impacted testing efforts and HONI resource requirements, which required leveraging necessary HONI SME institutional knowledge. ✓ HONI staff were stretched on multiple concurrent projects which resulted in resource constraints and impacts.	No change in scope

Overall, E Source found that scope evolution during execution was primarily driven by implementation realities, systems integration requirements, operational readiness considerations, and refinement of functionality required to support deployment at scale. The review also found that intentional investments in modern DI functionality[2] were aligned with the program's broader strategic objectives and long-term grid modernization goals.

[2] The term "modern functionality" in JRAP is equivalent to "modern DI functionality." Accordingly, this report uses "modern DI functionality" throughout.

Budget

The following findings represent the primary factors influencing budget performance and increases to the current ETC, as summarized in Table 4.

Table 4: HONI Budget Findings

#	Finding Category	Description	Cost Group
1	Initial Estimate Accuracy	✓ The AMI 2.0 solutions integration and deployment estimate was not market tested resulting in higher than original estimates upon vendor contract finalization.	✓ Technology ✓ Solution Integration
2	Solution Defects	✓ Solution and integration complexities resulted in a greater volume of defects identified during QA and required additional test cycles to resolve. ✓ Initial quality assumptions around the vendor solution were inadequate, resulting in a high defect rate. ✓ The complexity of integrating the new solution with existing systems impacted defect resolution and deployment. ✓ The varied methods for data compilation and synchronization have further extended defect resolution times, ultimately hindering HONI's deployment speed and capacity.	✓ Technology ✓ Solution Integration ✓ Deployment
3	Integration Complexities	✓ The CMEP process and enterprise software integration resulted in higher levels of effort and delays. ✓ The legacy HONI tool, SAP work manager, was inadequate for AMI 2.0, and the integration of the vendor's work management tool with HONI's process introduced workflow inefficiencies that increased cost.	✓ Solution Integration ✓ Deployment
4	Distributed Intelligence / Distributed Automation (DIDA)	✓ Intentional investments were brought forward based on the success of early DIDA trials of future-proofing grid edge strategies.	✓ Modern Functionality
5	Other	✓ Aging Infrastructure – higher than forecasted percent of poles were found to be unsuitable for new installation load and height needs, which led to unplanned costs. ✓ Resource Management – several factors impact the project's resourcing: capacity of HONI institutional knowledge SMEs and concurrent project resourcing.	✓ Deployment

E Source found that increases to the ETC were primarily associated with labor costs, systems integration complexity, deployment execution realities, solution readiness considerations, expanded testing and defect remediation activities, and evolving operational requirements identified throughout implementation. Several cost drivers were interconnected, particularly where integration complexity, deployment coordination, and solution maturity resulted in additional implementation effort, schedule impacts, and operational workarounds.

The review also found that HONI implemented mitigation measures intended to manage cost uncertainty and evolving program requirements and fixed-price contracting strategies as additional information became available during execution.

The September 2025 ETC for the AMI 2.0 program is approximately $799.4 million CAD, reflecting an increase of approximately $93.8 million CAD, or 13.3%, between 2023 and 2025. The updated estimate remains within the initial estimate range of $600.0 million CAD to $847.0

million CAD, representing approximately 85% to 120% of the most recent estimate, as illustrated in Figure 4 and Table 5.

Figure 4: HONI Budget Estimate History ($M CAD)

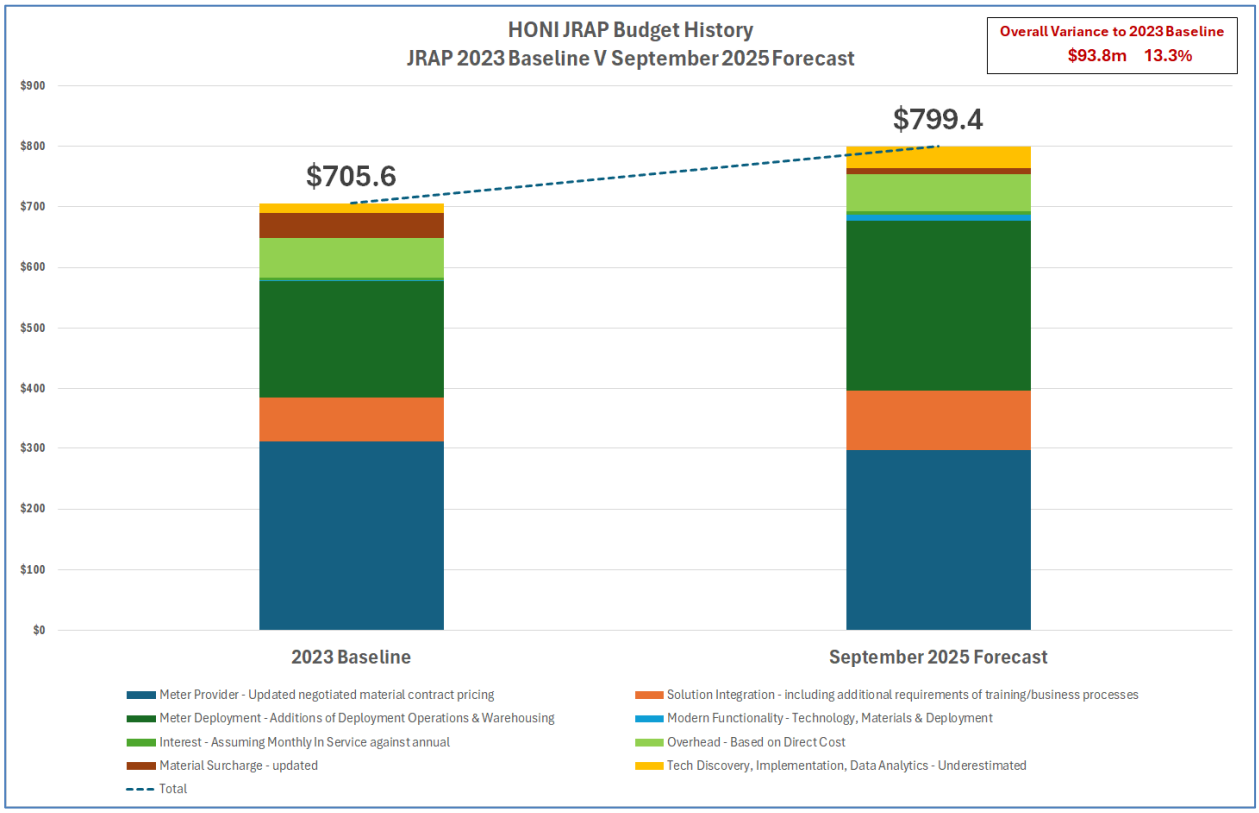
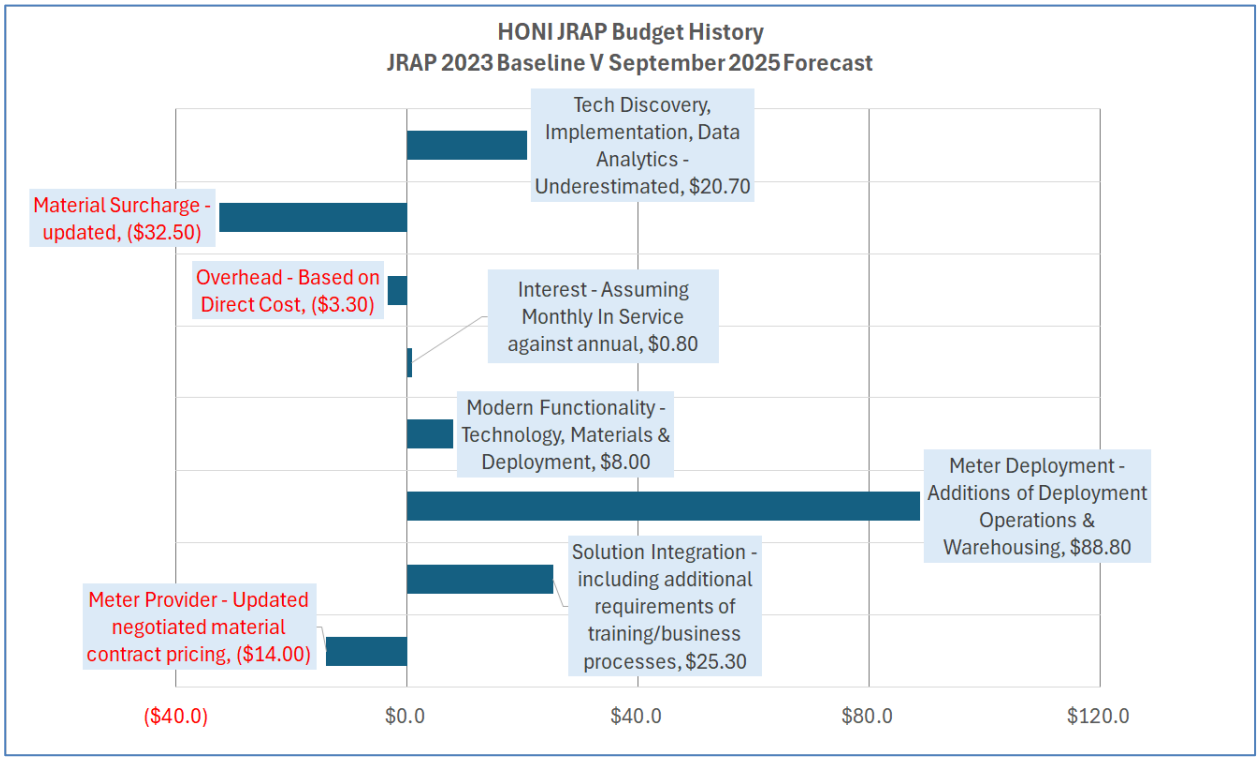


Table 5: HONI Budget Variance ($M CAD)

JRAP Categories	2023 Baseline	September 2025 Forecast	% Delta	$ Delta
Meter Provider - Updated negotiated material contract pricing	$311.7	$297.7	-4.5%	($14.00)
Solution Integration - including additional requirements of training/business processes	$73.7	$99.0	34.3%	$25.30
Meter Deployment - Additions of Deployment Operations & Warehousing	$191.9	$280.7	46.3%	$88.80
Modern Functionality - Technology, Materials & Deployment	$2.0	$10.0	400.0%	$8.00
Interest - Assuming Monthly In Service against annual	$4.1	$4.9	19.5%	$0.80
Overhead - Based on Direct Cost	$64.8	$61.5	-5.1%	($3.30)
Material Surcharge - updated	$42.1	$9.6	-77.2%	($32.50)
Tech Discovery, Implementation, Data Analytics - Underestimated	$15.3	$36.0	135.3%	$20.70
Total	**$705.6**	**$799.4**	**13.3%**	**$93.80**

The primary drivers influencing budget performance are illustrated in Figure 5.

Figure 5: HONI Budget Variance ($M CAD)



Schedule

The three schedule phases as defined in Project Baseline Section (and seen in Figure 3) are interdependent, starting with contracting and early planning and are sequential all the way through mass deployment. The following findings represent the primary factors influencing schedule performance, deployment sequencing, and execution timing identified through documentation review and stakeholder interviews, as summarized in Table 6.

Table 6: HONI Schedule Findings

Finding Category	Description	Mitigation
Contracting Delays (Phase 1)	✓ Phase 1 contracting negotiations with the integration and deployment contractor as well as labor unions took longer than anticipated.	✓ HONI issued partial SOWs for Phase 2 and Phase 3 to minimize further delay in initiating the field trial.
Technology / Solution Readiness (Phase 2)	✓ The unexpected need to use the vendor work management tool and the integration of the tool with HONI systems and processes took longer than planned. ✓ Solution shortcomings including lack of experience with Ontario version of CMEP.	✓ The close of Phase 2 was extended, and subsequent activities were executed in parallel to prevent further delays.
Integration Complexities (Phase 2)	✓ The CMEP process and enterprise software integration resulted in higher levels of effort and delays.	✓ Workarounds and automation have

Finding Category	Description	Mitigation
	✓ The varied methods for data compilation and synchronization resulted in unanticipated solutions scaling issues which hindered HONI's deployment speed and capacity (i.e., multiple head-end systems and IESO processes).	addressed immediate gaps. ✓ Additional mitigation to address these complexities includes shifting the schedule while not changing the scope.
Solution Defects (Phase 2)	✓ Solution and integration complexities resulted in greater volume of defects identified during QA required additional test cycles to resolve.	✓ Categorize defects and parse them into future releases according to priority.
Resource Mgmt. & Transition (Phase 2)	✓ Vendors experienced scarcity of complex meter installers in the market during the pilot which necessitated reliance on local HONI staff. ✓ HONI staff were stretched on multiple concurrent projects which resulted in Phase 2 Pilot resource constraints.	✓ HONI supplemented the effort with internal HONI experts in complex meter installs. ✓ HONI has implemented automation and strategic resourcing (e.g., testing) where possible to help buffer the schedule.
Outside Factors (Phase 2)	✓ Pilot deployment began later than planned in March 2025 and was also delayed multiple times due to external factors (e.g., the 2025 generational ice storm that required power restoration and constrained resources in the deployment area).	✓ HONI executed phases and activities in parallel to mitigate external factors that may cause delays.

E Source found that schedule impacts were primarily associated with extended contracting activities, systems integration complexity, solution readiness limitations, testing and defect remediation activities, and resource constraints identified during implementation. Several of these factors were interrelated and required adjustments to deployment sequencing, execution planning, and operational coordination activities throughout the program lifecycle.

Despite delays encountered during early implementation phases, the review found that HONI generally maintained overall schedule control through mitigation strategies including phased contracting, concurrent execution of activities, deployment planning adjustments, automation, and targeted resource management efforts. Even though the project is expected to extend a year longer than anticipated, this is not unreasonable for a project of this type and scale.

While execution sequencing and intermediate milestones evolved throughout implementation, the overall forecasted program completion date is only one year delayed compared to the original Project Baseline, as illustrated in Figure 6. Key schedule drivers included:

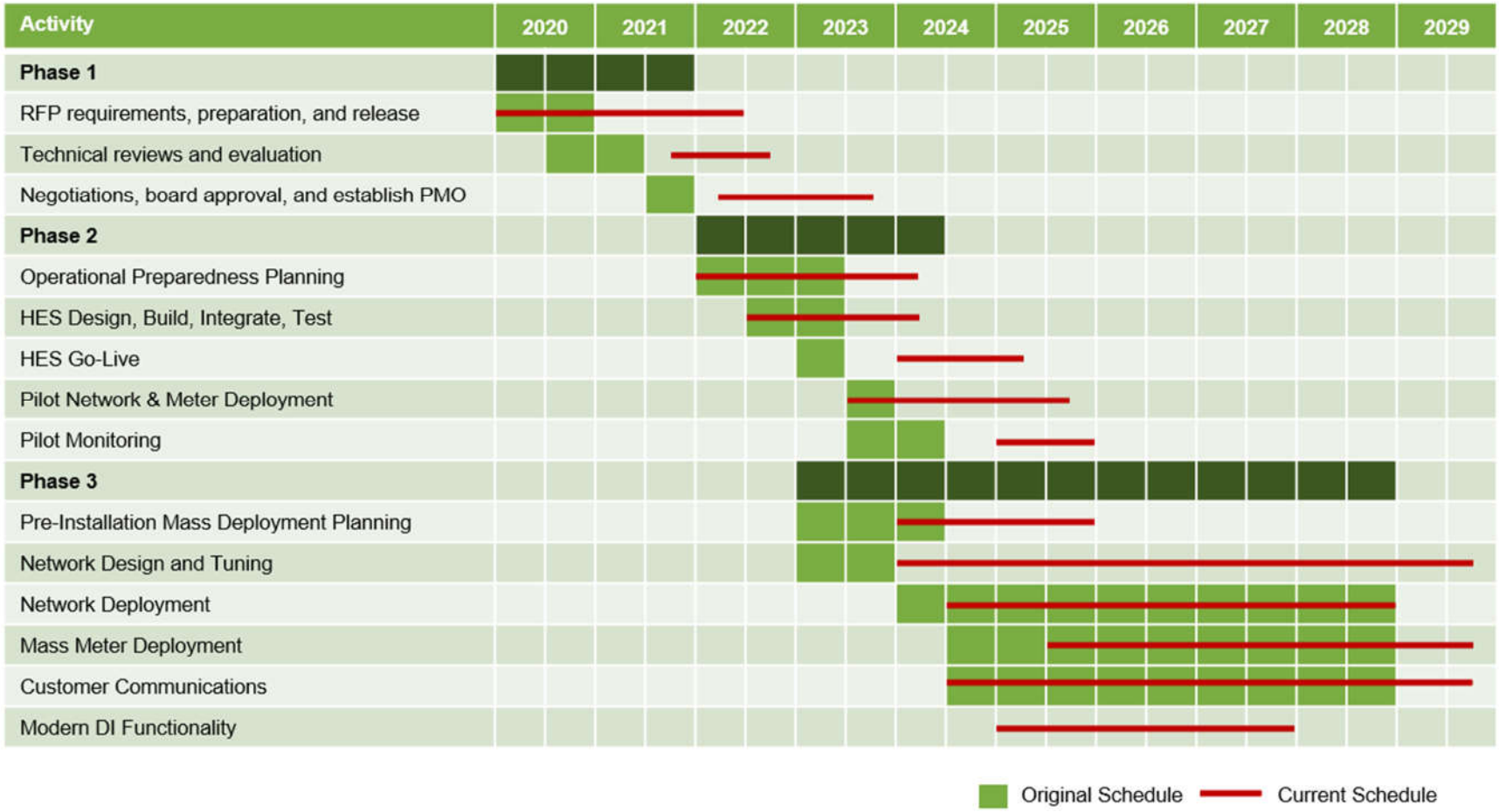
- Extended contract negotiations led to delays in Phase 1: Pre-Deployment.
- Phase 2: Head End System (HES) Implementation and Customer Pilot was originally scheduled to precede the start of Phase 3: Mass Deployment but was extended to overlap with Phase 3 to mitigate schedule delays.
- Despite delays during early program phases and execution challenges encountered during implementation, the overall forecasted project completion date was only delayed

one year because of mitigation strategies including parallel execution of activities and planned acceleration of deployment volumes in later years.

- HONI intentionally advanced DIDA scope to leverage pilot-proven AMI 2.0 functionality and available bundled application pricing opportunities. As meter deployment activities are not dependent on the DIDA implementation timeline, no overall program schedule impacts are expected.

The review also found that HONI adjusted execution sequencing and deployment planning to maintain overall program progress, including parallel execution of selected activities and planned acceleration of deployment volumes in later implementation phases.

Figure 6: HONI Schedule Findings



Market Scan

Scope

Table 7 and Table 8 summarize the AMI projects of the market scan group of utilities, including key program characteristics and operating considerations that may influence differences in deployment cost, execution complexity, and implementation timelines.

As discussed previously, direct comparison of AMI programs is inherently challenging due to differences in deployment scope, technology architecture, regulatory requirements, operating environment, labor structure, and implementation strategy. The market scan was therefore intended to provide directional context regarding HONI's AMI 2.0 execution relative to selected industry programs rather than direct one-to-one benchmarking.

Table 7: Common Scope Elements of the Market Scan Group of Utilities

Scope Item	HONI	Alectra	PSE&G	Ameren (Illinois)	BC Hydro	ComEd	National Grid (NY)	Eversource (MA)	SDG&E
Meters & Network Equipment	✓	✓	✓	✓	✓	✓	✓	✓	✓
Meter and Network Deployment	✓	✓	✓	✓	✓	✓	✓	✓	✓
External Solution/Systems Integration Support	✓		✓	✓	✓	✓		✓	✓
External Meter Installation Contractor	✓	✓	✓	✓	✓	✓	✓	✓	✓
Scope – core meter functionality, Outage Mgmt., RCRD	✓	✓	✓	✓	✓	✓	✓	✓	✓
Scope - distributed intelligence (DIDA), Analytic applications	✓		✓			✓	✓	✓	✓
External Project Management Support	✓	✓		✓	✓	✓	✓	✓	✓

Table 8: Service Territory Density and Key Project Challenges of the Market Scan Group of Utilities

Scope Item	HONI	Alectra	PSE&G	Ameren (Illinois)	BC Hydro	ComEd	National Grid (NY)	Eversource (MA)	SDG&E
# of Electric AMI meters per km of distribution lines[3]	11.9 meters per km	46.6 meters per km	63.2 meters per km	16.8 meters per km	33.8 meters per km	36.9 meters per km	22.0 meters per km	44.9 meters per km	56.6 meters per km
Key Challenges	CMEP, Higher than expected Contractor Costs , Solution Readiness	CMEP, Urgent Meter Replacement, Legacy Network Migration, Resourcing	Heavy Union, Transition from AMR-Manual Processes, AMI Pilot (16k)	Regulatory Complexity	Public Opposition & Opt-Out/ Mesh Network Build from scratch	4M Meters/ Funding & Regulatory Disruption	Network Issues, Supply, Billing Exceptions	Data & Cybersecurity Demands (3rd Party Risk)	Advanced Safety Requirements (Wildfire)

[3] Lower meter density, measured as fewer meters per kilometer of distribution lines, generally indicates a more geographically disperse service territory, which increases the effort and time required to deploy and replace meters across the grid.

All market scan utilities faced distinct challenges during their AMI implementations:

- HONI challenges included meeting the standards and complexity of the CMEP process which resulted in solution readiness issues. Additionally, contractor costs and contracting timelines that were higher and longer than expected, a sparse service territory with the lowest number of electric AMI meters per km of distribution lines, and the complex process of systematically collapsing legacy networks and head-end-systems without disrupting billing or other critical operations.
- Alectra's challenges included the urgent necessity to replace failing meters before securing regulatory funding, managing qualified meter technician resourcing, and the need to meet CMEP requirements. In addition, Alectra must transition from five legacy AMI networks and four head-end systems to a new AMI system while avoiding disruptions to billing operations and minimizing risk of non-communicating meters and degraded network performance during migration.
- PSE&G's AMI deployment was shaped by extensive labor negotiations associated with its heavily unionized workforce, an elongated regulatory rate case process, mandatory customer opt-outs, the transition from a complex mix of AMR and manual meter reading processes, and the progression from an initial AMI 1.0 pilot to a full-scale AMI 2.0 deployment.
- Ameren Illinois had to overcome an initial regulatory rejection and revise its AMI plan to better demonstrate customer value.
- BC Hydro faced significant customer pushback tied to health and privacy concerns about wireless meters, which ultimately led to a manual-read opt-out program. In addition, BC Hydro had to build its mesh network from scratch.
- ComEd faced legal, regulatory, and public challenges related to funding and cost recovery for its smart grid modernization program, which ultimately required legislative action to support continued AMI deployment. The scale of ComEd's deployment also introduced complexity, requiring the coordinated installation of more than 4 million smart meters across its service territory.
- National Grid (NY) experienced billing and deployment challenges, including billing exceptions requiring manual review, pockets of poor network connectivity that delayed meter registration, and constrained gas module availability that affected deployment timing.
- Eversource (MA) included software-enabled sensors in their AMI program that provide near-real-time data for third-party access, increasing overall complexity, cybersecurity risk, and data management costs.

SDG&E's AMI program is deploying advanced wildfire-related safety requirements, such as voltage-based detection capabilities to help identify downed or broken wires, increasing implementation cost and complexity beyond a standard AMI deployment.

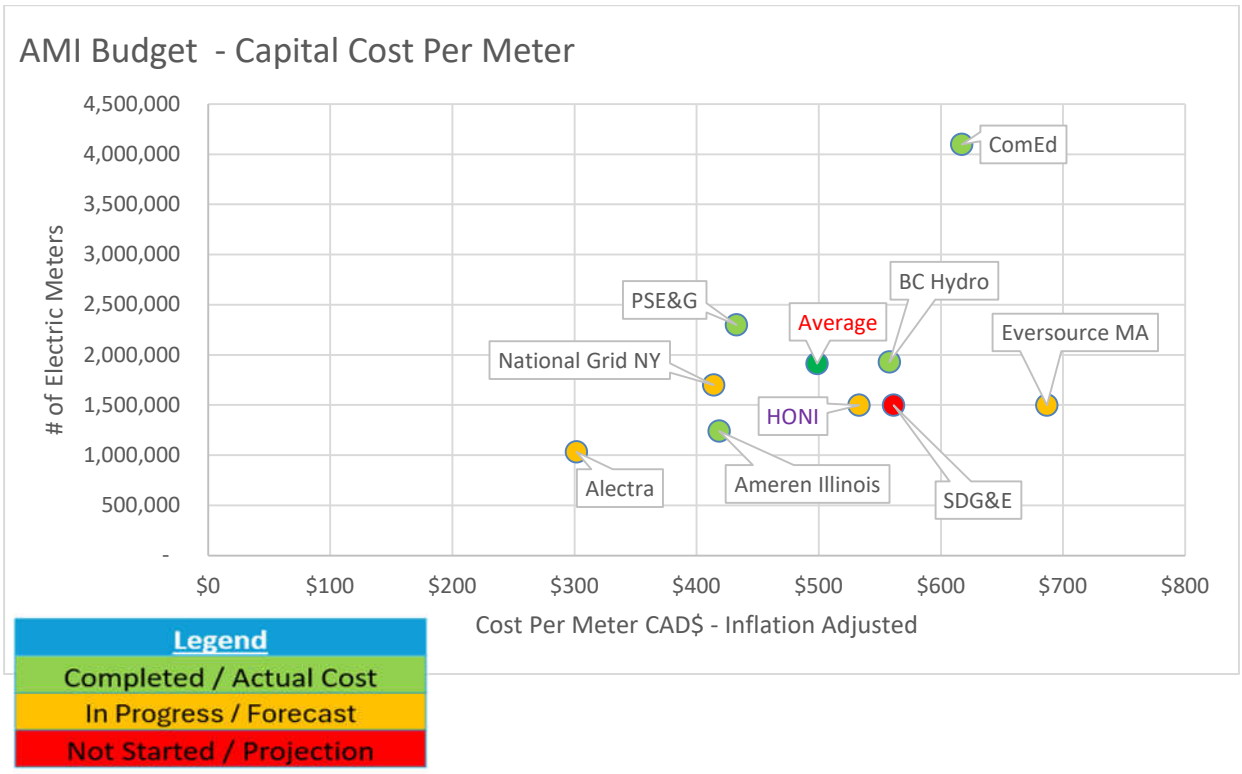
Budget

Based on the market scan of eight utility AMI programs, HONI's forecasted capital cost[4] per meter is approximately $532.93 CAD, while the average of the market scan utilities is approximately $498.70 CAD (adjusted for inflation) as illustrated in Figure 7.

While HONI's forecasted cost per meter is modestly above the group average, the market scan found that several program-specific factors contribute to this variance, including lower meter density, Ontario-specific regulatory and CMEP requirements, systems integration complexity, labor and deployment conditions, and inclusion of (modern) DI functionality investments. The market scan also noted that several utilities in the group experienced similar cost pressures associated with systems integration, deployment logistics, operational transition complexity, and evolving AMI functionality expectations.

Overall, E Source found that HONI's forecasted capital cost performance remains directionally consistent with the market scan group of AMI programs when differences in program scope, operating conditions, and implementation complexity are considered.

Figure 7: Market Scan Group - AMI Program Budget Capital Cost Per Meter



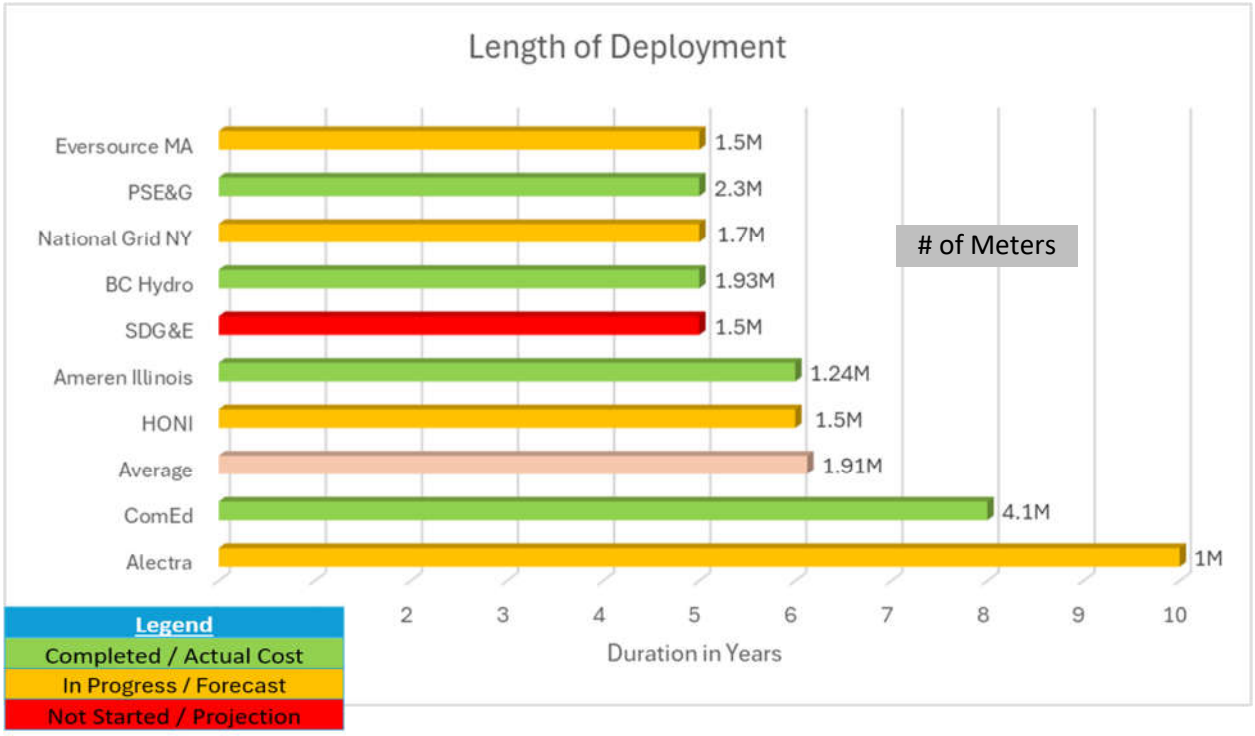
[4] Capital costs reflect investments in long-lived AMI assets and associated meter deployment activities that are typically subject to regulatory approval and recovered over time through utility rates, while other costs (e.g., O&M) reflect the ongoing expenses required to operate and support the AMI system.

Schedule

HONI's forecasted deployment duration is slightly below the market scan group average deployment timeline of approximately 6.125 years, with six of the eight utilities falling within approximately one year of HONI's projected deployment duration, as illustrated in Figure 8.

Despite execution challenges encountered during implementation, HONI's forecasted deployment timeline remains generally aligned with the market scan group of utility programs, particularly when considering the scale of deployment, lower meter density, coexistence of legacy and next-generation AMI environments, and Ontario-specific implementation requirements. However, a degree of meter deployment execution risk remains as annual meter deployment volumes have yet to be demonstrated in practice.

Figure 8: Market Scan Group - AMI Program Length of Deployment



SECTION IV – CONCLUSIONS

E Source conducted an independent review of HONI AMI 2.0 project execution process to evaluate whether the program's governance, scope management, budget performance, schedule management, and overall execution remain reasonable and justifiable relative to the original Project Baseline, the experience of the market scan group, and the inherent complexity associated with large-scale next-generation AMI deployments.

Based on the documentation reviewed, stakeholder interviews conducted, and a market scan performed, E Source concludes that HONI's AMI 2.0 project execution is prudent, appropriately governed, and generally consistent with challenges and execution realities commonly observed across AMI replacement and modernization programs throughout North America.

The review found that HONI established and maintained a structured governance and project management framework that includes formalized oversight, vendor management, risk and issue management, change control, performance tracking, and phased execution planning. These controls have enabled HONI to identify, escalate, and respond to evolving execution challenges while maintaining overall program direction and alignment with the strategic objectives established in the original JRAP filings.

E Source found that many of the challenges experienced during execution are characteristic of large-scale AMI replacement programs, particularly those involving extensive systems integration, evolving solution maturity, operational transformation, and regulatory-specific requirements. Key drivers influencing project execution included:

- Greater-than-anticipated systems integration complexity
- Ontario-specific CMEP and data synchronization requirements
- Vendor solution readiness and scaling limitations
- Increased field deployment and labor costs
- Expanded testing and defect remediation efforts
- Resource constraints associated with concurrent initiatives and specialized AMI expertise
- Additional infrastructure and operational realities identified during deployment activities

Importantly, despite these challenges, based on the evidence reviewed as part of this assessment, E Source determined that HONI implemented appropriate governance, project controls, and prudent project management practices. The reviews found that HONI generally responded to emerging risks and executional realities through mitigation strategies such as phased contracting, parallel workstream execution, defect prioritization, automation, revised deployment planning, and targeted resource adjustments.

The review also found that the evolution of project scope remained substantially aligned with the program's original strategic objectives, including replacement of end-of-life AMI infrastructure and enablement of broader grid modernization capabilities. Impacts to scope were justified and generally associated with integration requirements, operational readiness considerations, and intentional investments in (modern) DI functionality.

From a budget perspective, E Source found that the increases reflected in the current ETC are supported by identified and explainable cost drivers that are generally consistent with industry experience for AMI programs of similar scale and complexity. While HONI's forecasted capital cost per meter is modestly above the market scan group average, the review determined that the variance is directionally reasonable when considering differences in meter density, regulatory billing requirements, operating environment, program scope, labor conditions, and solution architecture.

Similarly, although the program experienced execution delays during early phases of implementation, E Source found that HONI maintained overall schedule control through mitigation planning and concurrent execution activities. The forecasted completion date extends one year beyond the original program timeline due to challenges associated with longer than estimated contract negotiations, solution integration, testing, deployment readiness, and external factors. The duration of mass meter deployment remains comparable to those of the market scan utility projects.

The market scan further demonstrated that many of the utilities in the group experienced similar challenges related to systems integration, deployment logistics, regulatory billing requirements, solution maturity, customer engagement, and evolving AMI functionality expectations. As such, the execution challenges encountered by HONI are not unique within the context of next-generation AMI programs.

Overall, E Source concludes that HONI's AMI 2.0 project execution, including its governance structure, management approach, scope evolution, budget adjustments, and schedule management, remains reasonable and supportable when considered against other industry programs and the complexity inherent in large-scale AMI 2.0 initiatives.

APPENDIX A – E SOURCE QUALIFICATIONS

E Source Overview

E Source is a utility-focused research, advisory, consulting, and data science firm that has supported utilities across North America for nearly 40 years. E Source works with electric, natural gas, water, and multi-service utilities to help evaluate complex business and technology decisions, strengthen operational performance, improve customer outcomes, and support effective execution of critical infrastructure and technology investments.

E Source combines industry research, market intelligence, technology expertise, and implementation experience to provide practical, evidence-based guidance to utility clients. As a vendor-neutral advisor, E Source does not sell AMI technology or represent AMI vendors. This position enables E Source to provide independent perspectives grounded in utility needs, industry experience, and practical execution realities.

AMI Experience and Expertise

E Source has supported the utility AMI/AMR industry for more than two decades, from early AMR-to-AMI transitions through current AMI 2.0 planning, deployment, and optimization programs. E Source has supported more than 240 utilities and 425+ AMI projects, including AMI strategy, assessments, business cases, regulatory support, vendor procurements, pilot design, meter replacement planning, systems integration, deployment support, operational readiness, and full AMI system implementations.

E Source's AMI consulting team brings experience across customer, operations, grid, data, and technology domains. The team has worked with leading AMI vendors, communications providers, meter installation vendors, MDMS platforms, systems integrators, and utility project teams. This experience informs E Source's ability to evaluate AMI program scope, technology architecture, integration requirements, vendor capabilities, deployment strategies, operational impacts, and the people and process changes required to realize value from AMI investments.

Relevance to the AMI 2.0 Project Execution Process Review

This experience is directly relevant to Hydro One Networks Inc. AMI 2.0 Project Execution Process Review. AMI 2.0 programs are not simply meter replacement initiatives; they involve coordinated execution across field deployment, communications infrastructure, enterprise systems integration, data management, customer and billing processes, operational readiness, vendor performance, and long-term sustainment.

E Source's experience supporting both AMI planning and implementation provides an informed perspective on how program decisions, vendor solution maturity, integration complexity, deployment conditions, and operational requirements can influence scope, budget, schedule, and overall execution performance. This implementation-informed perspective supported E Source's ability to assess HONI's AMI 2.0 execution against the established Project Baseline and a group of North American utility AMI programs.

Relevant Qualifications

- **Specialized AMI expertise:** E Source has extensive experience supporting AMI strategy, business case development, regulatory support, vendor evaluation, procurement, piloting, integration, deployment, and operational readiness.
- **AMI 2.0 and modernization perspective:** E Source helps utilities evaluate next-generation AMI capabilities, including distributed intelligence, outage management, voltage monitoring, advanced analytics, customer programs, and event-driven use cases.
- **Implementation-informed advisory:** E Source's work across both planning and execution provides visibility into how early program decisions affect systems integration, deployment, sustainment, operational readiness, and long-term value realization.
- **Current AMI market intelligence:** E Source's work across North America provides insight into AMI technology trends, vendor capabilities, deployment approaches, implementation challenges, and peer utility practices.
- **Vendor-neutral perspective:** E Source does not sell AMI technology or represent vendors, allowing its assessments and recommendations to be grounded in utility objectives, operating conditions, and execution realities.
- **Utility-focused experience:** E Source works exclusively with utilities and understands the regulatory, operational, customer, and technical considerations that influence large-scale AMI modernization programs.

Practices of Distribution Loss Reduction Approaches in North America

Project 1-119985

September 10, 2026

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

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TERMINOLOGY DEFINITIONS

Conservation Voltage Reduction:
The concept of operating the distribution system at the lower end of the allowable range through active feedback controls every minute of every day, as an effort to reduce energy consumption.

CVR Factor:
The Ratio of Load Changes per Voltage Reduction

Feeder:
A primary distribution circuit in utility lingo

Power Factor:
The ratio of Real Power to Total Power, which ranges from 0 for fully reactive loads, to 1 for fully resistive loads. Can also be calculated as the Cosine of the phase angle difference between voltage and current in an AC circuit.

Reactive Power:
Power which oscillates to and from capacitors and inductors every ½ cycle.
Real Power:
Power which is transmitted to resistive loads performing work.

Technical losses:
Power lost during the transmission and distribution of electricity. It is calculated as the square of the current multiplied by the complex impedance.

VAR (Volt-Ampere Reactive):
The reactive component of the complex total load.

VVO (Volt/VAR Optimization):
Uses near real-time information to reduce losses, improve reliability, and improve power quality using capacitor banks, voltage regulators, transformer load-tap changers, and DER through volt/VAR controls.

Voltage Drop:
The reduction of voltage in an AC circuit which is calculated as the current multiplied by the complex impedance.

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1 INTRODUCTION

This report describes EPRI's comprehensive analysis of distribution loss reduction approaches currently employed by utilities in North America.

Background

The distribution of electricity results in some loss of electrical energy. Typically, energy loss is small compared to the total amount of energy delivered to customers. Nonetheless, the energy loss represents material (and in some cases direct) cost to the distribution utility. These energy losses are commonly referred to as "Technical Losses", in contrast to losses due to theft which are commonly referred to as "Non-Technical Losses". This report will only deal with reductions of Distribution System Technical Losses.

Technical Losses on an electric distribution system refer to the energy lost as heat or electromagnetic radiation, occurring in the conductors, transformers or other equipment due to the resistance of the wire and magnetic losses of windings. The largest proportion of losses on the electric distribution system follows the general formula of:

$$P_{Loss} = I^2 \, x \, Z$$

Where: P_{Loss} = *Power Loss in Watts*
I = Current flowing through the conductor or transformer in Amperes
Z = Impedance of the conductor or transformer in Ohms

This is commonly referred to as "I^2Z losses". What is important to note here is that to reduce losses you have two main options: (1) Reduce the current flowing through the conductors; or (2) Reduce the Resistance of the conductors or transformers. The loss reduction strategies that will be discussed will address one or both of these options.

Location of Losses

While losses can occur in every conductor or piece of equipment on the system, certain areas contribute more significantly to the overall amount of losses and are the key targets for loss reduction efforts. The following table provides general estimates for peak losses broken down by portion of a typical distribution system.

Table 1 – Estimated Losses by Portion of a Typical Distribution System [1]

Portion of the System	Peak Losses as a % of System Demand
Substation Transformers (HV/MV) , LTC, Regulators	1.0 – 2.0%
MV Conductors	4.0 – 6.0%
Distribution Transformers (MV/LV)	1.0 – 3.0%
LV Conductors	1.0 – 3.0%
Total Peak Distribution Technical Losses	**7.0 – 14.0%**
Non-Technical Losses (in North America)	<1.0%

Loss Reduction Methods

There are a variety of methods employed by distribution utilities to mitigate system losses. Each of these, has a set of potential benefits, affects system complexity, and may have some unintended negative consequences. Several of the most prominent methods include:

- Raising MV Voltage Levels (e.g. conversion from 4kV to 13kV, etc.)
- Volt Var Optimization
- Conservation Voltage Reduction
- Reconductoring (increasing conductor sizes)
- Feeder Topology Reconfiguration (seasonal based on planning studies)
- Splitting Ancillary / LV networks
- Maintaining proper load balancing between phases
- Installing More Efficient Distribution (MV/LV) Transformers

[1] Flinn, D.G., Hall, S., Morris, J., Cummings, A.B., and Northcote-Greene, J.E.D., *Improved Methods for Distribution Loss Evaluation*, EPRI EL-3261, October 1983

System Geography Impacts

It should also be recognized that the geography of the service territory itself plays a significant role in the range of losses expected. This is because, as noted in Table 1 (above) the Medium Voltage Conductors themselves are a large contributor to losses. In areas where customers are spread out widely, the distance the medium voltage feeders must travel to serve the load is greater. The necessary and required longer medium voltage conductors are higher in impedance (which is a function of the length) which increases the losses, in a manner that cannot be changed.

Evaluation of Benefits

The technical benefits of the different loss reduction strategies described above vary significantly. To provide a mechanism for comparison of the different strategies, a series of detailed power flow studies were performed by EPRI experts using sample feeders from Hydro One of various voltage classes and initial conditions. This analysis resulted in characterization of the potential benefits of each strategy, which have been categorized by the percentage reduction of the **Total Peak Distribution Technical Losses** (as defined above). The categories that have been utilized are described in the table below:

Table 2 - Benefit Categories for Loss Reduction

Benefit Category	Description
High Benefit	Reduce **Total Peak Distribution Technical Losses** by > 2.00%
Medium Benefit	Reduce **Total Peak Distribution Technical Losses** by 0.5 – 2.00%
Low Benefit	Reduce **Total Peak Distribution Technical Losses** by < 0.5%

The HIGH, MEDIUM, LOW categorization is meant to imply a relative category of the loss mitigations methods, not imply that this results in a HIGH magnitude reduction of losses.

For instance, a 2% reduction in losses, which is 2% of the 7% total load which is only 0.14% of total load.

2 EPRI SURVEY OF LOSS REDUCTION DEPLOYMENTS

EPRI developed and issues a survey focused on implemented practices for reducing losses on the electric distribution system. The survey was completed by 22 North American (US and Canada) utilities of various sizes and organizations. The intent of the survey was to identify utilities who have active loss reduction programs, and to further identify the drivers for those programs, and the benefits of those programs. The results of that survey are presented below.

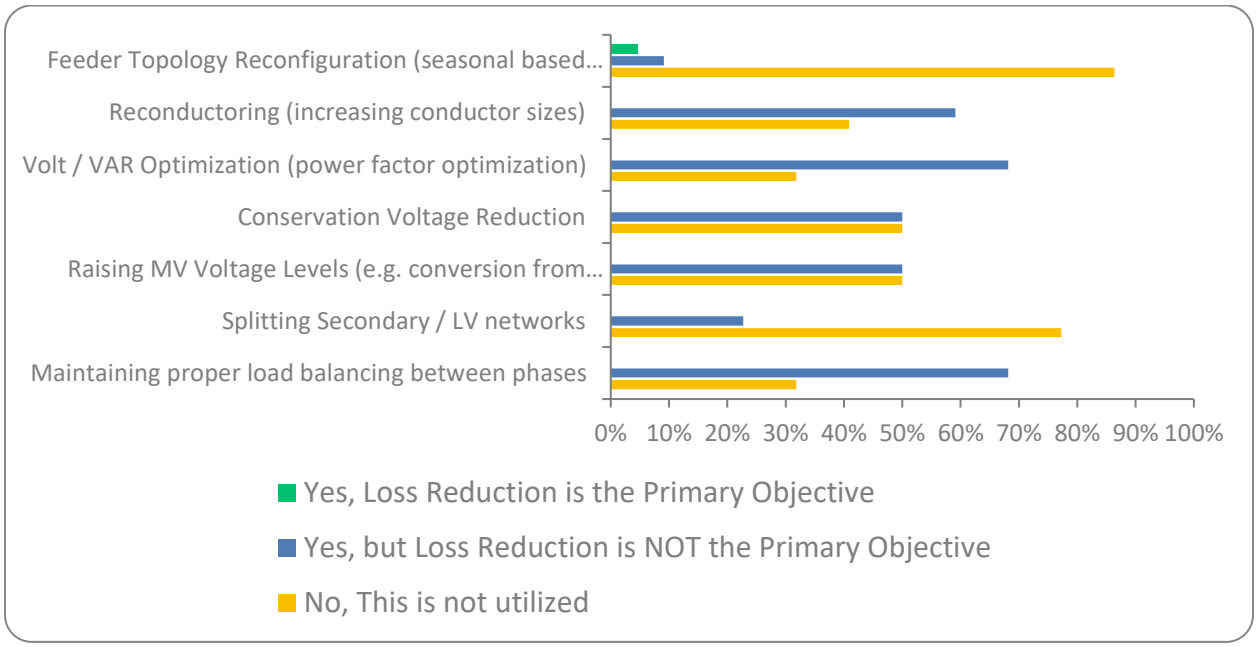


Figure 1 - Results of Survey - Application of Loss Reduction Methodology

The key learnings from this survey include:

1. **Loss Reduction is seldom a primary driver for investment**
2. **Loss Reduction strategies are not always apparent. They are often embedded into planning criteria or distribution feeder design standards.**
3. Loss Reduction is more often a desirable incidental benefit associated with other primary objectives:
    a. Reliability
    b. Load Growth
    c. Voltage Conversion (e.g. 4kV → 13kV)
    d. Volt / Var Optimization Deployment Enabling Conservation Voltage Reduction

3 RAISING MV VOLTAGE LEVELS (E.G. CONVERSION FROM 4KV TO 13KV, ETC.)

Raising the nominal operating voltage of a distribution feeder is a method to increase distribution system capacity and retire aging infrastructure. Along with these primary objectives, raising the nominal operating voltage also has the ancillary benefit of reducing losses. Raising the nominal operating voltage is a very significant investment, typically requiring new poles, new conductors, new insulators, new crossarms, new distribution transformers, and new lighting arrestors.

Loss Mitigation Mechanism

Total power (kVA) in a distribution conductor is proportional to the voltage and the current (kVA = kV x I). Using this formula, it can be calculated that increasing the primary operating voltage to 2x the original value will cause the conductor current to drop by 50% while maintaining the same feeder power flow. Recalling the power loss equation:

$$P_{Loss} = I^2 \, x \, Z$$

Using this formula it can be determined that if the current is reduced by 50%, the resultant P_{Loss} diminishes to 25% of the original P_{Loss}.

Results of Survey

Eleven of the 22 respondents indicated that they were actively performing voltage conversion projects, **but all of them said loss reduction was an ancillary benefit,** with primary benefit identified as addressing overloads by increasing capacity, retiring obsolete equipment, or improving reliability/resilience.

Benefit Analysis

The results of the power flow investigation indicate that voltage conversion projects have a **HIGH BENEFIT** to loss reduction. Current flowing through the medium voltage feeder drops by the inverse ratio as the voltage is raised, proportionately reducing the losses.

4 VOLT / VAR OPTIMIZATION (POWER FACTOR OPTIMIZATION)

Distribution engineers / operators manage the system voltage using several methods, including regulating Var flow at the distribution level. This typically is achieved by installing capacitor banks locally on the distribution feeder, which reduces the need for Var support from the transmission (or upstream) system. ***An ancillary objective of Volt/Var control is the reduction of system technical losses.***

Loss Mitigation Mechanism

The main function of power system capacitors is to help supply the reactive power requirements for lagging power factor loads on the system (e.g. AC motors, air conditioners, heat pumps). Capacitor banks reduce the magnitude of reactive current flow through the system, which in turn reduces the I^2Z losses. In the diagram below the Green Arrow represents the Current providing Real Power, while the Yellow Arrow represents the Current providing Reactive Power. In the top diagram both are supplied by the Transmission System, thus the distribution system experiences I^2Z losses for both. In the bottom diagram, the reactive power is supplied locally by the addition of a capacitor bank, thereby reducing the current on the upstream portion of the feeder, and thereby reducing I^2Z losses.

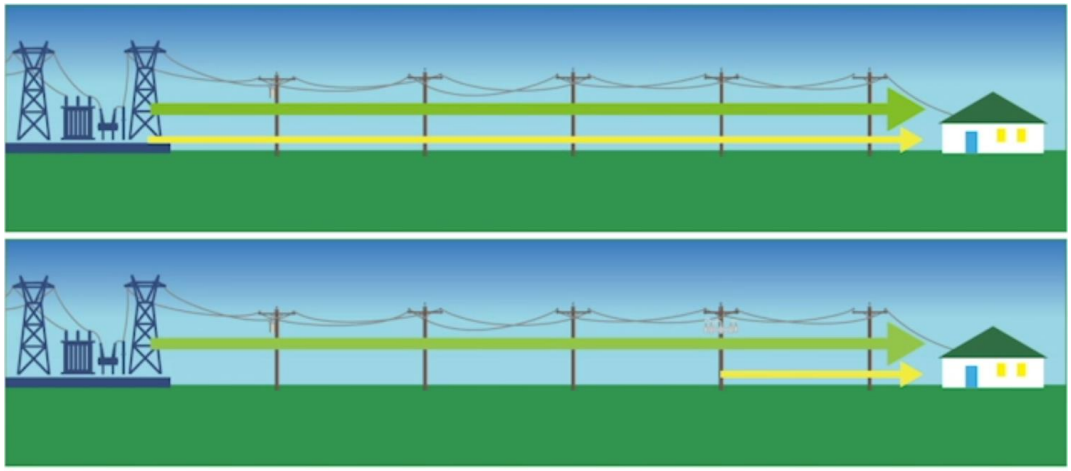


Figure 2 - Capacitors Reduce Current and I^2Z Losses on Distribution System

The location of capacitor banks on a distribution feeder is very important to maximizing the primary system benefits of regulating voltage, as well as the ancillary benefit of reducing losses. Determining the optimal locations can be accomplished through “rules of thumb”, manual analysis, or using algorithms provided by commercially available power flow solutions.

The ideal placement of capacitors on a feeder would be to distribute them exactly as the reactive load is distributed. This is not practical because many small capacitor banks of various sizes would be needed. Practically, a standard-sized capacitor bank(s) can be located at a key

point(s) on a feeder where reactive power support is needed. Effective capacitor bank placement requires analysis of the feeder topology, and system loading and reactive power requirements for different loading seasons.

Results of Survey

Fifteen of the 22 respondents indicated that they operate a Volt Var Optimization solution, **but all of them said loss reduction was an ancillary benefit,** with primary benefit identified as regulating feeder voltage, optimizing power flow, and maximizing feeder capacity.

Benefit Analysis

The results of the power flow investigation indicate that Volt Var Optimization solutions have a **LOW BENEFIT** to loss reduction. As described, capacitor banks minimize the reactive current flowing through the feeder mains to supply reactive power, thus reducing losses.

5 CONSERVATION VOLTAGE REDUCTION

Conservation voltage reduction (CVR) refers to the regulation of delivered service voltage to the lower end of the acceptable range to reduce peak power demand and/or energy consumption. For many years, utilities have used voltage reduction to reduce demand during periods of peak consumption (known as Conservation Voltage Reduction – Demand). More recently, some utilities have deployed this strategy on a 24x7 basis to reduce the overall energy consumption on the electric distribution system (known as Conservation Voltage Reduction – Energy).

This effect is best illustrated with the example of an incandescent light bulb. Since this light bulb is essentially a resistive load, the power consumed by the light bulb is calculated using

$$Power\ (P)=V^2/\mathrm{Z}$$

Where V is the voltage applied to the light bulb and Z is the impedance of the light bulb

Following this formula, if impedance is constant and voltage applied is reduced, then power (electric power consumed by the light bulb) is also reduced. As a numerical example, if voltage is reduced from 124 volts to 122 volts (reduction of approximately 1.6%), with R = 153.76 ohm (resistance of a 100-watt incandescent light bulb), power is reduced from 100 watts to 96.8 watts (reduction of approximately 3.2%). In recent years, this effect has waned, as modern devices are less responsive to this voltage induced demand reduction. EPRI has found that new devices, such as LED lighting, personal computers and newer AC units have a lower benefit from CVR than older devices.

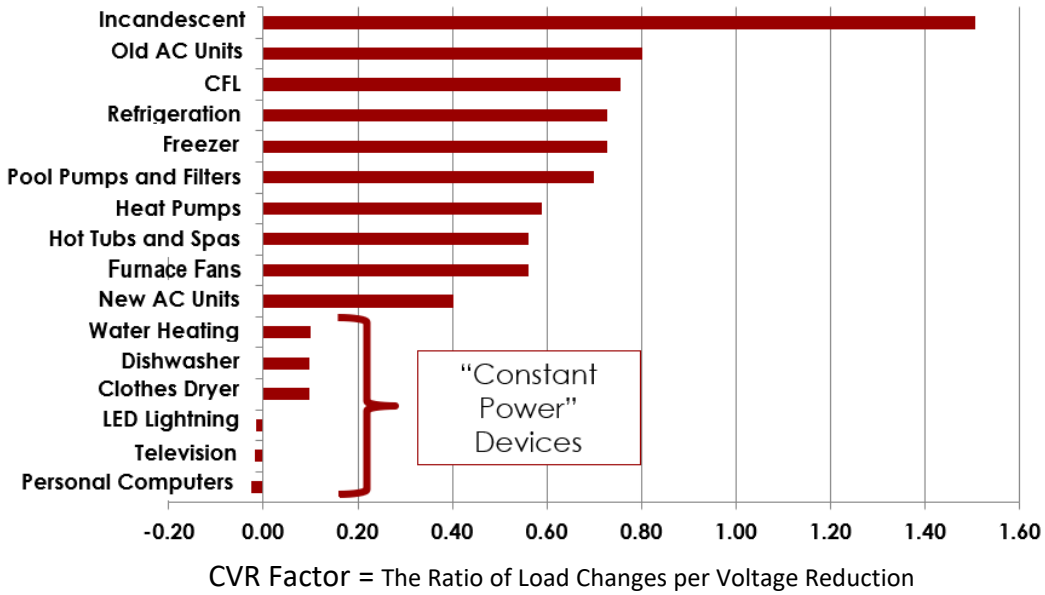


Figure 3 - CVR Factor for Common Devices – Showing Waning Benefits for Newer Devices

Loss Mitigation Mechanism

Reducing the delivered voltage will cause some end use devices to consume less power, reducing the current required to serve those devices. This reduced current, in turn reduces the 1^2Z losses in the conductors and transformers supplying those end-use devices.

Results of Survey

Eleven of the 22 respondents indicated that they utilize some form of Conservation Voltage Reduction, **but all of them said loss reduction was an ancillary benefit,** with primary benefit identified as minimizing peak demand and/or minimizing energy delivered to customers. The typical reasons that Conservation Voltage Reduction programs are deployed are in response to local regulatory mandates. It should be noted that Conservation Voltage Reduction is much more difficult to accomplish on utility systems with long rural feeders, given the significant voltage drop involved, driving much lower benefit potential / investment ratios.

Benefit Analysis

The results of the power flow investigation indicate that Conservation Voltage Reduction projects have a **LOW BENEFIT** to loss reduction. As described, reducing voltage can impact the current required to serve loads, depending on the type of load being supplied. The potential benefits of CVR have waned as modern loads such as LED lighting, EV Chargers, and switched power supplies for electronics are not as responsive to system voltage changes.

6 RECONDUCTORING (INCREASING CONDUCTOR SIZES)

Increasing the size of the conductor on a portion of a distribution feeder (commonly referred to as reconductoring) is a technique used by distribution utilities to increase feeder load capacity, or increase the ability of the feeder to enable the connection of Distributed Energy Resources. An ancillary benefit of reconductoring with a larger conductor is the reduction of losses.

The selection of conductor sizes for reconductoring projects (or for new feeder installations) is made using common industry wide standard calculations that take into account the expected loading, the voltage regulation requirements, loss minimization, system reliability, and the total cost of ownership of the asset.

Loss Mitigation Mechanism

The size of the conductor used on a distribution line has a significant effect on the efficiency of the line. Larger diameter conductors have lower Impedance, resulting in less loss than smaller conductors of the same material for the same current. Recall that losses are determined by I^2Z, so the effect for reconductoring using a larger conductor is to reduce the Impedance.

Results of Survey

Thirteen of the 22 respondents indicated that they perform reconductoring on their system, **but all of them said loss reduction was a incidental benefit,** with primary benefits identified as resolving overload/thermal issues, resolving voltage regulation issues, or facilitating Distribution Automation restoration switching or Distributed Energy Resource installations.

Benefit Analysis

The results of the power flow investigation indicate that Reconductoring projects with larger conductors have a **LOW BENEFIT** to loss reduction. As described, reconductoring with a larger conductor reduces the impedance of the conductors, proportionately reducing the amount of losses. In practice, the impedance differences between existing conductors and the largest standard conductor are not sufficient enough to generate significant loss minimization benefits to justify reconductoring purely for loss reduction.

7 FEEDER TOPOLOGY RECONFIGURATION (SEASONAL BASED ON PLANNING STUDIES)

Seasonal Feeder Topology Reconfiguration is a practice that sometimes occurs on a seasonal basis, responding to systems that are partially Winter Peaking and partially Summer Peaking. Portions of feeders (1-3 MW) are transferred to other feeders prior to the Winter and Summer season to balance forecasted loading. This provides several benefits including deferment of capital expansion investments, balancing of loading, and an ancillary benefit of reducing losses.

Loss Mitigation Mechanism

Losses are reduced by this method because by balancing the loading between two feeders on a seasonal basis the total of the current squared portion of the I^2Z calculation is minimized.

Results of Survey

Two of the 22 respondents indicated that they utilize some form of Seasonal Feeder Topology Reconfiguration **with one of them utilizing this solution primarily for loss reduction.** Typically the primary benefits of this strategy include addressing overloads/thermal issues, and deferring capital expansion investments. It should be noted that this solution only makes technical sense in geographic areas where you have both Hot Summers and Cold Winters, in locations where areas with Natural Gas available for heating are adjacent to areas without Natural Gas. In these areas there will be opportunities to transfer sections of feeders back and forth seasonally to optimize the topology for the upcoming season. Specifically, this is not possible in areas with long radial feeders without large populations of feeder ties.

Benefit Analysis

The results of the power flow investigation indicate that Feeder Topology Reconfiguration projects have a **LOW BENEFIT** to loss reduction. These switching activities are optimizing the topology at a very low level, which is likely why very few utilities are doing this.

8 SPLITTING ANCILLARY / LV NETWORKS

Ancillary (LV) conductors (between the distribution transformer and the customer premise) are a significant source of losses. This is because, at the lower service level voltages (e.g. 120 or 240) the current flowing through the lines is high, therefore the 1^2Z losses are high. In places where the ancillary conductors are overloaded or the voltage drop on the secondary conductors is excessive, it often makes sense to split the ancillary into two segments, and add a distribution transformer to serve the additional segment. While primarily deployed to address loading or voltage issues, this also reduces system losses.

Loss Mitigation Mechanism

Losses are reduced by this method because splitting customer loading between two distribution transformers reduces the current on the LV conductors, thereby minimizing the total current squared portion of the I^2Z calculation.

Results of Survey

Four of the 22 respondents indicated that they actively split ancillary (LV) networks, **but all of them said loss reduction was an ancillary benefit,** with the primary benefit identified as addressing overload/thermal issues, addressing voltage regulation issues, or preparing for increases in feeder demand.

Benefit Analysis

The results of the analytical investigation indicate that Splitting Ancillary Networks projects have a **LOW BENEFIT** to loss reduction.

9 MAINTAINING PROPER LOAD BALANCING BETWEEN PHASES

Distribution feeders are three phase circuits which primarily serve single phase loads. This inherently creates the challenge of loading the individual phases in a balanced manner. Imbalanced loads lead to a number of significant problems including potential false tripping of a protective relay, inability to maximize utilization of system capacity and an increase in the amount of losses generated by the system.

Remedies

The remedy for phase load imbalance typically falls into one of three possible solutions:

1. Entire single-phase primary lateral may be moved at its point of connection to another phase of the three-phase main branch to achieve large scale balancing.
2. Individual Transformers may be moved from one phase to another by manually relocating the primary tap from one phase to another to achieve the desired balance.
3. New transformers and loads may be added in a manner to address future balancing.

Loss Mitigation Mechanism

Imbalance between phases causes one or more phases to carry more current than the other(s). By balancing the load evenly between the phases, the sum of the squares of the current on all three phases are minimized thereby minimizing the total 1^2Z losses for that feeder system.

Results of Survey

Fifteen of the 22 respondents indicated that they actively manage Feeder Load Balancing, **but all of them said loss reduction was an ancillary benefit,** with the primary benefits identified as improving protection coordination, assisting with cold load pickup, improving voltage regulation, improving overload/thermal issues, balancing voltage for 3-phase customers, and reducing outage times.

Benefit Analysis

The results of the power flow investigation indicate that Feeder Load Balancing projects have a **MEDIUM BENEFIT** to loss reduction.

10 INSTALLING MORE EFFICIENT DISTRIBUTION TRANSFORMERS

Types of Transformer Losses

The overall losses in a distribution transformer are composed of two major types: No-Load Losses and Load (or Variable) Losses. Management of these losses is accomplished in very different ways, so it is important to understand the difference, and how they can be mitigated properly.

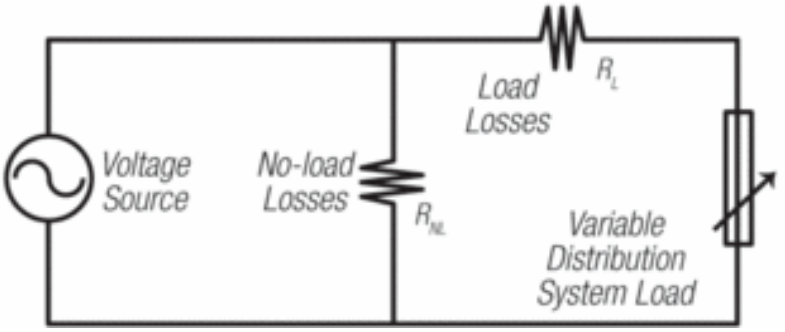


Figure 4 - Types of Losses in a Transformer (outlined in the green dashed box)

No-Load Losses

No-load losses in a transformer are the energy losses that occur when the transformer is energized but not supplying any load to its output terminals. There are two main ways to impact no-load losses: (1) Replace the transformer with a more efficient model or (2) lower the operating voltage.

Load (Variable) Losses

Load losses, are a type of loss that occurs in transformers due to the flow of electrical current through the conductors, resulting in resistive heating. Load losses are directly proportional to the square of the current flowing through the winding coils (I^2) and the resistance (R) of the conductors.

Loss Mitigation Mechanism

In Canada standards govern the design of more efficient new distribution transformers. Utilities and transformer manufacturers abide by these regulations in their specifications and designs, which are factored into their purchase requests for new transformers.

Additionally, the selection of transformer sizes and configuration for specific installations at the utility abide by “Total Cost of Ownership” calculations that factor in expected loading, voltage regulation requirements, and losses .

Results of Survey

This was not part of the survey.

Benefit Analysis

The results of the power flow investigation indicate that Efficient Transformer projects have a **LOW BENEFIT** to loss reduction.

11 SUMMARY

Based on EPRI's experience and research, line losses are almost never the primary driver for investments. Rather, loss reduction is an ancillary benefit. In general, these investments are made for a variety of other purposes, notably managing capacity or thermal limits and/or regulating delivered voltage.

Table 3 - Summary of Loss Reduction Mitigations

Method	Benefit Mechanism	Benefit	Survey Results Summary		
			Yes, Loss Reduction is the Primary Objective	Yes, but Loss Reduction is NOT the Primary Objective	No, This is not utilized
Raising MV Voltage	Reduce Current by increasing supply voltage	High	0%	50%	50%
Volt Var Optimization	Supply Reactive Load with Capacitors, reducing current	Low	0%	68%	32%
Conservation Voltage Reduction	Reduce demand by reducing delivery voltage.	Low	0%	50%	50%
Reconductoring	Reduce Impedance by increasing conductor size	Low	0%	59%	41%
Feeder Topology Reconfiguration	Balancing load between feeders or substations minimizes losses	Low	5%	9%	86%

Splitting LV Networks	By splitting load between overloaded MV/LV transformers or LV segments, overall losses are reduced	Low	0%	23%	77%
Maintaining Proper Load Balancing between Phases	Balancing loading between phases reduces total losses	Medium	0	68%	32%
Efficient Transformers	Improved transformer design leads to improvement in no-load and load losses	Low	n/a	n/a	n/a

Loss Reduction Embedded in Industry Practices

Based on EPRI's experience and research, lines losses are almost never the primary driver for investments. These loss reduction best practices and tools are embedded in industry practices and standards of utilities.

These embedded practices and tools include:

- Criteria for selecting primary conductor sizes – choosing conductor sizes that are appropriate for the loading levels and voltage regulation criteria, which inherently also minimize losses
- Criteria for ancillary conductor selection and ancillary bus length – choosing conductor sizes and lengths appropriate for present and future loading levels which inherently also minimizes losses.
- Criteria for selecting distribution transformers – Procuring transformers that are appropriate for the loading levels and total cost of ownership, which inherently also minimize losses

- Strategic Capacitor Deployment – Deploying capacitor banks in substations and/or distribution feeders to match and offset reactive power demand, and deploying switched capacitor banks, as necessary, all of which inherently reduce losses.
- Incorporating load balancing ancillary goals into feeder expansion project design criteria
- Adding SCADA measurements at the substation and on feeders to collect current and voltage measurements to support planning studies and reports.
- Utilizing a Planning Power Flow computer software solution that imports the Geographic Information System (GIS) feeder model, and enables various load, voltage, and loss minimization analyses

Guidehouse

Hydro One Vulnerability Assessment and System Hardening

Vulnerability Study and Benefit Cost Analysis

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Disclaimers

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Executive Summary

The OEB's Vulnerability Assessment and System Hardening (VASH) Framework[1] requires that all Ontario electricity distributors include a VASH analysis in rebasing applications for 2028 rates. The Framework specifies that distributors are expected to integrate a VASH analysis in their Distribution System Plan (DSP).

Distributors are expected, as part of their VASH analysis, to

- **Complete a vulnerability assessment** (VA) identifying the parts of the distribution system most vulnerable to extreme weather and other climate-related events.
- **Conduct a pre-assessment** to determine whether technically and economically feasible system hardening investments exist.
- **Undertake a benefit-cost analysis** (BCA) if the pre-assessment identifies potentially suitable candidates for system hardening (or other) resilience investments.

Hydro One engaged Guidehouse Canada, Ltd. (Guidehouse) in February 2026 to prepare a VASH analysis as an input to the DSP to be included in Hydro One's Joint Rate Application (JRAP). In addition to identifying the assets and feeders in its service territory most vulnerable to the evolving severity of key climate perils, Hydro One tasked Guidehouse with undertaking a pre-assessment and BCA for five resilience measures (RMs). Guidehouse completed its analysis at the end of March 2026. This report summarizes the methods and results of this work.

The OEB allows distributors to choose between "custom" and "generic" VASH options. The generic option requires the distributor use an Excel workbook Toolkit published by the OEB to support its analysis.

Guidehouse elected to undertake a VASH analysis using a customized version of the generic Toolkit. Most of the adjustments Guidehouse applied to this Toolkit provide greater flexibility in modeling – for example to perform BCAs for multiple iterations of the RM within a single workbook, or to allow for the replacement of some (but not all) baseline[2] assets with RM assets.

In performing the BCAs for the five candidate RMs, Guidehouse evaluated resilience benefits – the benefits associated with reducing the frequency or criticality of *force majeure* outages.[3] Guidehouse's approach to calibrating projected outage frequency and quantifying the value of outages to customers deliberately excludes consideration of "normal" reliability outages. Any such reliability benefits that might be realized from the RMs modeled in this work would be incremental to the benefits included in this analysis.

This VASH analysis is intended to act as an input to Hydro One's planning process. The VASH's Vulnerability Assessment provides a system-wide assessment of fragility which the Pre-Assessment and BCA leverage to develop a review of the resiliency improvement potential across the distribution network. This provides Hydro One planners with alternatives to consider as they prioritize investment and develop resilience improvement programs targeted to maximize the value

[1] Ontario Energy Board, *Vulnerability Assessment and System Hardening Report*; *EB-2024-0199 – Vulnerability Assessment and System Hardening (VASH) Project*, October 2025

Available at: https://engagewithus.oeb.ca/vulnerability-assessment-system-hardening

[2] "Baseline assets" are those assets modeled that would be expected to be in place absent any resilience measure implementation.

[3] Guidehouse understands that Hydro One uses the term *force majeure* to describe outages that the OEB refers to as the Major Events that are excluded from the calculation of Hydro One's reporting and record-keeping requirements (RRR) reliability metrics. Guidehouse's reporting has adopted this term (*force majeure)* to be consistent with the naming conventions of its client.

to Hydro One customers in a manner consistent with Hydro One's standard investment planning and implementation process.

Hydro One staff have noted that the RMs included in this VASH analysis were developed alongside its other planned investments in the context of Hydro One's DSP development process, which had begun prior to the release of the VASH Framework. Hydro One considers the customer benefits of resiliency throughout its planning process, as it does other important value streams, such as customer safety and reliability.

These RMs were selected by Hydro One for inclusion in the VASH analysis either because of their focus on hardening, or because of their anticipated reduction of *force majeure* outage criticality. Hydro One has noted that these RMS are a selection of planned programs and investments anticipated to provide Hydro One customers with resilience value.

Vulnerability Assessment

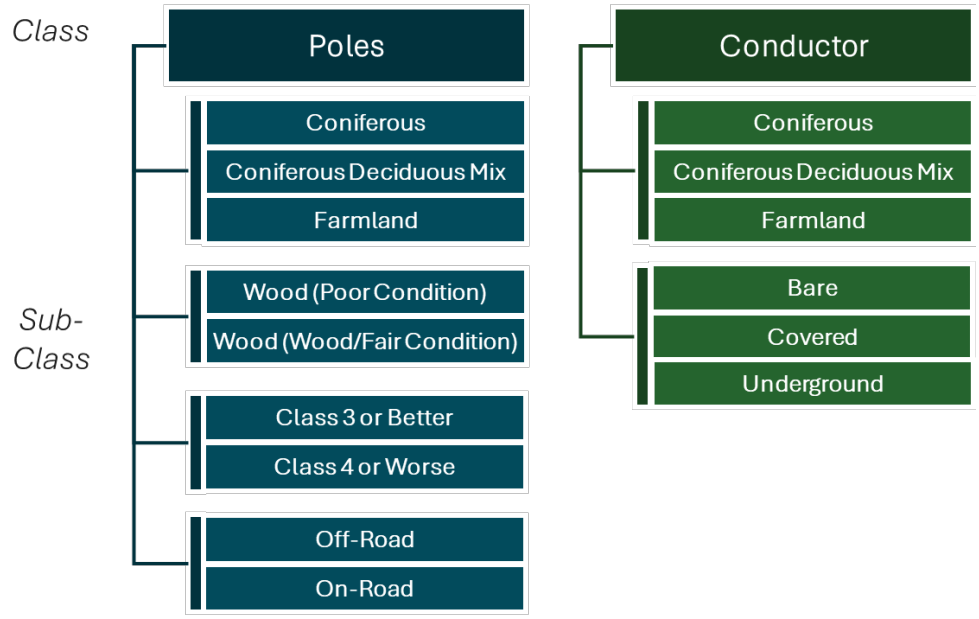
Guidehouse's analysis considered the two climate perils for which severity return intervals (e.g., 1-in-100 severity events) have been provided by the OEB in its Toolkit[4]: ice accretion from freezing rain and wind speed. Consultation with Hydro One staff (including Forestry staff) confirmed that these two perils were the primary weather-based drivers of *force majeure* (resiliency) outages.

The analysis focuses on two asset classes: poles and conductor. These classes were selected in consultation with Hydro One on the basis that these were assets most susceptible to the climate perils included in this analysis. As described in Section 3.0 and Appendix C the "pole" asset class implicitly includes pole-top transformers, and the "conductor" asset class implicitly includes cross-arms. A review of the repair codes assigned to *force majeure* outages (once non-relevant cause coded outages – e.g., "Scheduled", "Human Element", etc. had been removed) showed that all such codes could be mapped to one of the asset classes included.

Many sub-classes of each of these asset classes were modeled. Figure 1 illustrates the asset characteristics for which sub-classes were defined. Altogether, 39 asset sub-classes (combinations of these asset characteristics) were modeled.

[4] The VASH Toolkit was issued by the OEB in October 2025 as part of the VASH Framework to assist distributors evaluate hardening options. It is available at: https://engagewithus.oeb.ca/vulnerability-assessment-system-hardening

Figure 1. Asset Sub-Class Characteristics



A failure threshold for both climate perils was estimated for each asset sub-class based on professional and academic asset fragility literature and informed by the expertise and experience of Hydro One asset management and forestry staff. Asset vulnerability is determined by the application of these failure thresholds to the probability that projected climate perils' severity will exceed the thresholds.

These "exceedance probabilities" are derived from the data and methods provided by the OEB in its Toolkit. Guidehouse's VA adhered to the format of the generic Toolkit, undertaking an asset-based approach, and assessing the fragility of Hydro One's assets in the face of changes in the severity of climate perils projected by Environment and Climate Change Canada (ECCC) through 2100.

The VA was applied to "Feeder Archetypes". A Feeder Archetype is defined by the average distribution of assets per feeder drawn from one of eight feeder groupings (one for each Hydro One region[5] for both F-Class and M-Class feeders[6]) and the exceedance probabilities of one of 230 locations for which distinct climate projections are available and to which each Hydro One feeder was mapped. The VA considered the vulnerability of 327 of these Feeder Archetypes.

Consistent with the OEB's generic VA Toolkit, the vulnerability assessment itself is agnostic to the *value* associated with the probability of asset failure (e.g., the value of lost load to customers associated with asset failure-driven outages – this value is considered in the BCA). The VA identifies only which asset sub-classes and which Feeder Archetypes are likely to be most vulnerable to the modeled climate perils in the future. The VA provides a relative, not an absolute, ranking of asset and feeder vulnerability. Vulnerability ranking applied to individual feeders in a subsequent step (the Pre-Assessment) of the analysis introduces consideration of the potential value of addressing a given feeder's vulnerability.

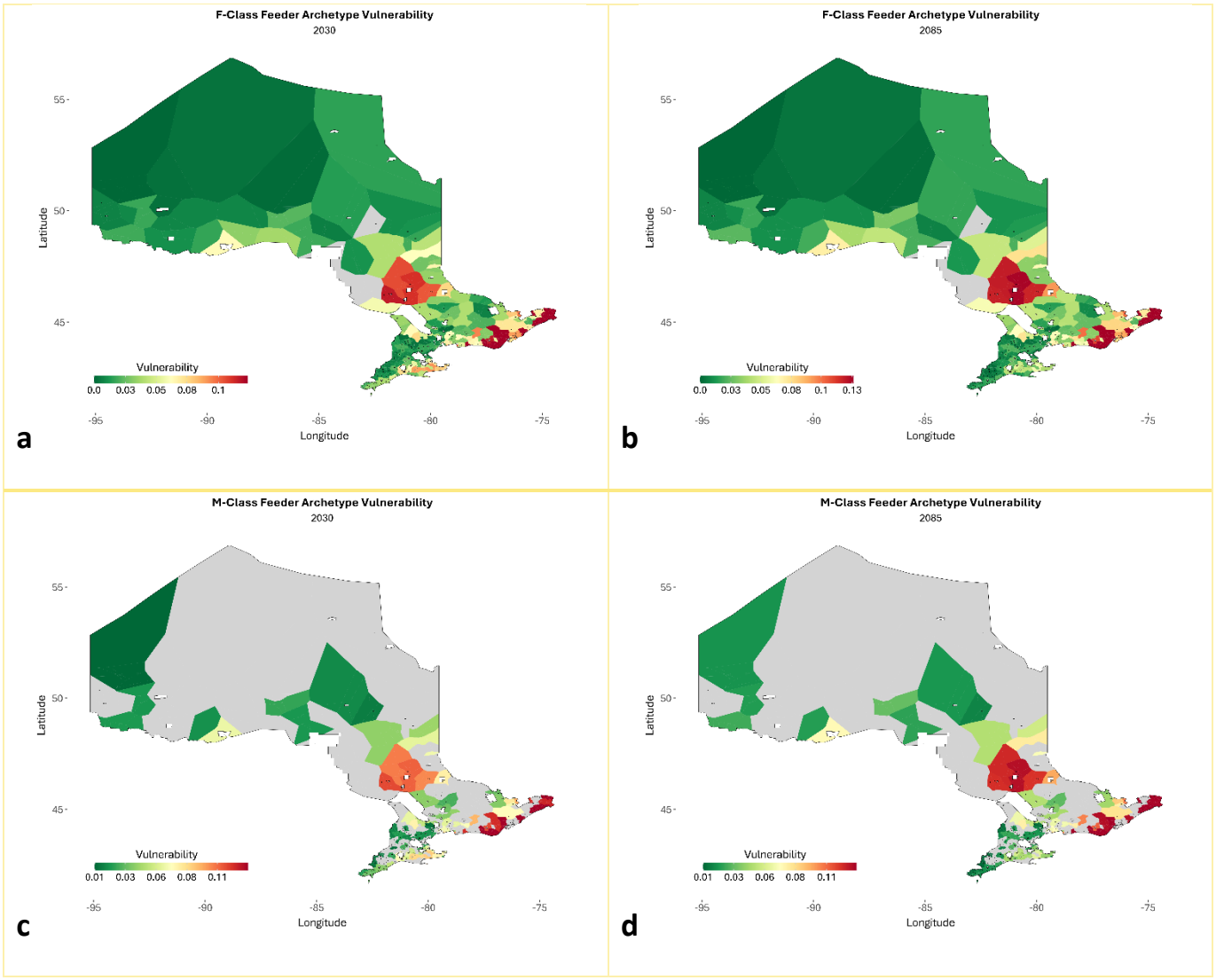
[5] The Hydro One service territory is divided into four regions: North, Central, East, and South.

[6] M-Class feeders are supplied by Transformer Stations. F-Class feeders are supplied by Distribution Stations. M-Class feeders can accommodate supply to Distribution Stations, large customers, and other distributors, as well as other types of final load.

Figure 2 shows the vulnerability of F- and M-Class feeders at the Feeder Archetype level across the service territory in 2030 (panel a and c, the top and bottom quadrants on the left of the figure) and 2085 (panel b and d, the top and bottom quadrants on the right of the figure). As per the scale in the bottom-left corner of each panel, red areas are projected to be the most vulnerable, dark green the least. This figure illustrates the relative vulnerability of Hydro One's distribution assets to the two climate perils considered under the ECCC projections using the Representative Concentration Pathway (RCP) 6.0 that Guidehouse has, consistent with the direction of the VASH Framework[7], used for this VASH analysis.

[7] The OEB recommends "*aligning with the CSA approach of using RCP 8.5 for asset classes with expected useful lives less than 60 years and RCP 6.0 for asset classes with expected useful lives greater than 60 years.*" The assumed service (accounting) life of the two assets considered in this VASH analysis are approximately 60 years (poles) and approximately 65 years (conductor).

Figure 2. Relative Vulnerability of F- and M-Class Feeder Groups in 2030 and 2085 under RCP 6.0



Relative vulnerability of F- (panels a and b) and M-Class (panels c and d) Feeder Groups in 2030 and 2085 under RCP 6.0. Feeders are mapped to the substation at the head, gray areas indicate no mapped substation. a) 2030 F-Class vulnerability. b) 2085 F-Class vulnerability. c) 2030 M-Class vulnerability. d) 2085 M-Class vulnerability.

The top two panels illustrate the relative vulnerability of F-class feeder assets in 2030 and 2085. This shows how this relative vulnerability for the less populated (and generally lower voltage) F-class feeders changes over the period of analysis. The bottom two panels show how the relative vulnerability of M-class feeder assets change from 2030 to 2085. M-class feeders generally serve more customers and are a higher voltage than F-class feeders.

Both F- and M-Class feeders in the East region exhibit the highest relative climate vulnerability, clustered in the region in which both ice accretion and wind speeds are projected to be most severe.

Despite exposure to comparable projected wind severity, the South region is shown to be relatively less vulnerable at present – shown in panels a and c - because assets are typically less vegetated than in other regions. The South is also projected to become less vulnerable over time as shown in

panels b and d, -as the severity of ice accretion is projected to migrate north in the later periods. Those Central region Feeder Archetypes that are most vulnerable are those clustered on the north eastern shores of Lake Ontario, in the climate regions of Port Hope and Oshawa.[8]

The notable vulnerability of Feeder Archetypes in the near-North region (in the climate regions of Sudbury, North Bay, and Espanola) is principally a reflection of the ice accretion peril projected severity, which is projected to increase materially in this region, and the relative vegetation of the assets.

Hydro One's Resilience Measures

To improve the resilience of its distribution system to high wind and ice accretion events, Hydro One is considering a portfolio of climate mitigation and resilience measures. These RMs are designed to reduce the frequency of outages due to asset failures or the duration of outages when they fail.

Guidehouse included five of these RMs in its VASH analysis. These are listed in the table below.

Table 1. Summary of Resilience Measures

Resilience Measure	Description	Modeled Benefits
1. Clustered Hardening	The replacement of poor condition poles on a targeted feeder. Replacement poles are, where possible, a higher class (more resilient) pole.	**Reduced outage frequency** provides value of lost load (VoLL) benefits to Hydro One customers. Planned replacement or repair of vulnerable assets reduces costs associated with asset failure in storm conditions. In addition to the benefits above, undergrounding yields avoided operations and maintenance expenses associated with vegetation management.
2. Covered Conductor	Segments of approximately 3 km of targeted feeders' conductor are replaced with covered conductor to reduce faults from tree contact.	
3. Selective Undergrounding	Segments of between 1 and 3 km targeted feeders' overhead conductor (and a corresponding number of poles) are removed and lines are relocated underground. In the BCA this RM is applied only to feeders identified as potential candidates by Hydro One.	
4. Sectionalization	Switches, reclosers, and ties to adjacent feeders are applied to the targeted feeders.	**Reduced outage criticality**[9] for the targeted feeder, and for the

[8] Hydro One distribution feeder heads (transformer stations) were mapped to climate locations (geographic regions to which a given set of climate projections apply) using GIS data. Guidehouse understands that climate location names (e.g., Port Hope and Oshawa) refer to the location of the weather station providing the historic data used by ECCC to develop the climate projections for that region. Hydro One distribution assets may fall within climate locations named after towns (e.g., Oshawa) that are not directly served by Hydro One's distribution network.

[9] The VASH Framework defines criticality as the impact that is realized when "*the project reduces the expected outages' durations and/or the number of customers impacted by an outage without reducing the frequency of these events.*"

Resilience Measure	Description	Modeled Benefits
	In the BCA this RM is applied only to feeders identified as potential sectionalization candidates by Hydro One.	adjacent feeder to which the targeted feeder is temporarily transferred via tie transfer schemes.
5. Voltage Conversion & Sectionalization	Sectionalization is applied following a voltage conversion on the targeted feeder. In the BCA this RM is applied only to feeders identified as potential candidates by Hydro One.	

Additional detail regarding these RMs may be found in Section 3.0 of this report.

Pre-Assessment

The VA is a comprehensive assessment of the vulnerability of Hydro One's assets and feeders. The BCA, which follows the VA, is an assessment of the value to customers of mitigating that vulnerability on a set of *targeted* feeders.

The pre-assessment step helps to determine which feeders should be targeted as part of the BCA.

The pre-assessment is undertaken in three steps:

1. **Individual Feeder Vulnerability Ranking.** A customer-weighting metric, specific to each individual feeder, is applied to Feeder Archetype vulnerability scores to develop a ranked list of feeders from the most to least vulnerable. This "vulnerability" rank reflects both the fragility of the assets on the feeder identified as part of the VA *and* the potential value associated with mitigating outages on that feeder. The weighting metric used accounts both for the average count of customers impacted by outages during prior *force majeure* events per year (for period 2021 through 2025) and the number of customers served by the feeder. The result is a vulnerability ranking based on forward-looking climate probabilities and informed by observed history.
2. **Candidate Feeder Identification.** Hydro One has performed independent analyses to identify viable candidates for the Selective Undergrounding, Sectionalization, and Voltage Conversion and Sectionalization RMs. The BCAs for these RMs were limited to these groups of candidate feeders.
3. **Develop Average Program Feeders (APFs).** APFs are groupings of feeders averaged together to test the cost-effectiveness of the RMs. APFs enable, per Section 5.2 of the VASH Framework, the use of "*a single BCA… to support a program intended to address multiple, similar needs that may exist at different locations within the distribution system.*"

   While Feeder Archetypes are groupings developed to *comprehensively* catalogue asset vulnerability, the APFs are *targeted* groupings of feeders used in the benefit-cost analysis. The way that feeders are selected into these groups is intended to explore the potential monetary value the RMs offer as a function of the vulnerability of the feeders to which they are applied.

   Up to six APFs are defined for each BCA: three F-Class and three M-Class.

   APF characteristics (e.g., asset counts, historical average outage frequency, etc.) are averages of the feeders included in the given APF. The different APFs are defined for each BCA to explore

the sensitivity of the BCA to the average vulnerability of the feeders considered for RM implementation. Where one APF may include *all* feeder candidates for an RM, a different APF may consider, for example, only the 50 candidate feeders ranked as most vulnerable.

Understanding how APFs are developed and what they represent is critical for interpreting the results of the BCA.

For each RM Guidehouse developed three APFs for each feeder class (M and F) – a total of six APFs per RM BCA. The first APF for each feeder class within an RM's BCA is the most expansive and includes all possible candidate feeders. The subsequent two APFs include progressively fewer feeders in their averaging, focusing in on increasingly vulnerable groups of feeders. That is, the second and third APF (by class) for each RM moves up the list of vulnerability ranked feeders and assesses the value of the RM to a progressively more targeted group of feeders.

Benefit Cost Analysis

The BCA is an assessment of the customer value drawn from each of the candidate resilience measures developed. The BCA is conducted in a manner consistent with the direction provided by the OEB in its VASH Framework and BCA Framework.

The primary benefits considered are reduced customer outage frequency and criticality, and (where relevant) reduced asset repair and replacement costs. The principal costs are the capital costs associated with the RM investments.

No reliability benefits are included in this analysis.

All benefits derived from reduced outages or asset failures are those associated with outages and failures resulting from *force majeure* events, and not "normal" reliability events.

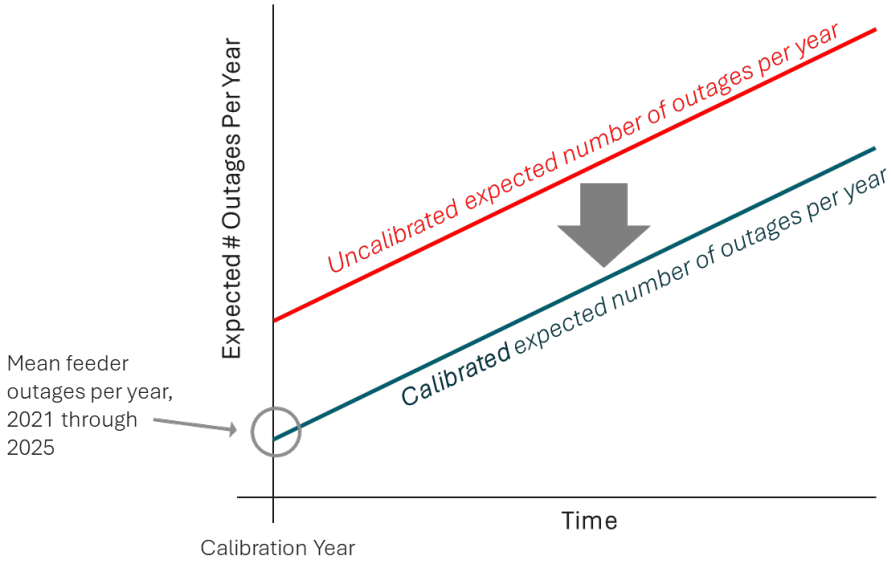
Benefits are assessed by taking the difference between the projected cost of outages (as measured by the value of lost load) and asset failures to customers under a baseline scenario (i.e., prior to implementation of RMs) and the projected cost of outages and asset failures to customers under each resilience measure scenario.

Outage Frequency

Projected outage frequency is a probability-weighted expected value, derived from the product of asset counts and their probability of failure in any given year. Probabilities of failure are derived from the APF's climate exceedance probabilities, which are averages of the individual feeders' climate location-specific exceedance probabilities.

Projected outage frequency is calibrated in the base calibration year (2026 for this analysis) to the average frequency of *force majeure* outages experienced by the feeders included in the APF from the five-year period of 2021 through 2025. This is the approach specified in the VASH Framework and the OEB's Toolkit, as illustrated in Figure 3.

Figure 3. Illustration of Outage Frequency Calibration



Outage Criticality

Each outage's criticality is defined by customer minutes interrupted (CMI - the product of customer counts and outage duration). The value of reduced outage frequency is determined by the average criticality (the average CMI) assumed for each event and therefore avoided when event frequency is reduced. Guidehouse has *not* adjusted this value (baseline CMI per event) on a going-forward basis to reflect growth in customer counts. All else equal, this will understate future customer costs per outage (i.e., benefits will be understated).

Each of the resilience measures is modeled as either reducing outage frequency (Clustered Hardening, Covered Conductor, Selective Undergrounding) or outage criticality (Sectionalization, and Voltage Conversion and Sectionalization). Historical outage frequency and criticality values are asset-specific (e.g., only pole-based outages are considered for Clustered Hardening), and include only *force majeure* events. This excludes any benefit from non-*force majeure* reliability impacts.

The Value of Lost Load

The value of lost load (VoLL) to customers is estimated by applying a $/CMI outage cost to the product of outage frequency and criticality. The unit cost for VoLL is drawn by Guidehouse from the Lawrence Berkeley National Laboratory's Interruption Cost Estimate (ICE) calculator. [10] This is a tool originally intended to estimate the costs to customers of "reliability" interruptions and is specified by the VASH Framework as an adequate source for VoLL estimates in the absence of custom distributor-specific system characteristics.

Due to differences in the length of *force majeure* outages, and the breadth of customers and assets they impact (compared to "normal" reliability outages), the ICE calculator may understate the cost to customers of such resilience outages. Guidehouse understands that the ICE calculator was not designed to capture the cost impact of lengthy regional extreme weather events affecting a large number of customers. For example, the ICE Calculator may not fully account for the loss of

[10] Lawrence Berkeley National Laboratory. Interruption Cost Estimate Calculator (v2.2.0). ICE Calculator. Accessed February 2026.

sanitation facilities, emergency services and disruption of fuel supply and travel restrictions during regional extreme weather events such as the 1998 Ice Storm.

Though the differing value of $/CMI across customer classes is accounted for in this analysis through the use of ICE calculator options and publicly available annual consumption averages by customer class, Guidehouse did not have outage data divided by customer class, or feeder-level distributions of customers by class. The VoLL estimates will therefore (for example) understate the VoLL benefits of RMs applied to feeders that serve a disproportionate share of large commercial and industrial (C&I) customers.

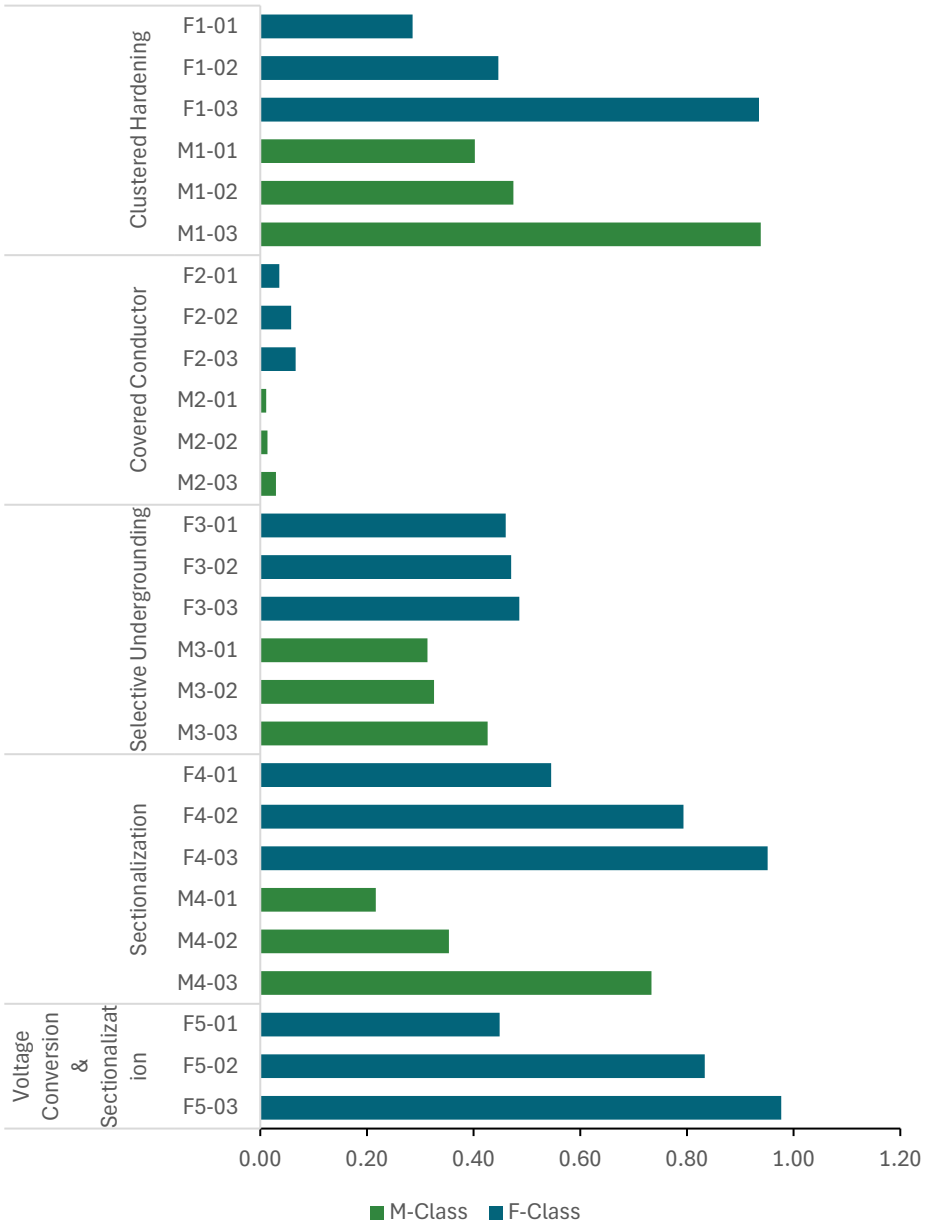
Finally, Guidehouse has not applied any assumptions of customer growth in its analysis. The value to customers of reduced outages assumes no change in the number of CMI per outage other than the impacts of those RMs modeled to reduce outage criticality. All else equal, growth in the number of customers served by a feeder would be expected to increase CMI per outage and therefore the benefits of the RMs. The result of this conservative assumption may be to understate the probable future value of the RMs.

Benefit-Cost Analysis Results

The BCA delivers a benefit-cost ratio (BCR) for each APF and each RM. These are calculated as the present value of the benefits divided by the present value of the costs. Consistent with the OEB's BCA Framework these tests are presented from the perspective of Hydro One's customers. This is reflected in the treatment of capital costs and the use of the social discount rate to capture the time value of money.

Figure 4 provides a summary of the BCRs for each APF and RM. APFs are numbered according to the feeder class ("F" or "M") they represent, the RM they are being used to test, and where they appear in the sequence of APFs for a given RM. For example, F3-02 is an F-Class APF for the third RM (Selective Undergrounding) and is the second of three F-Class APFs tested for that RM.

Figure 4. APF Benefit-Cost Ratio Summary



The Covered Conductor APFs' BCRs are quite low, all of them falling below 0.1. This is not unexpected. Most benefits associated with covering conductor would be expected to flow from reliability, not resilience, impacts – for example: reducing outage frequency due to incidental tree contacts.

In contrast, the BCA for the Clustered Hardening RM demonstrates that the resiliency benefits nearly match the costs it imposes. The early retirement of poor condition poles and replacement by higher-class poles offers significant VoLL benefits, and helps to reduce high post-*force majeure* event equipment replacement costs.

Sectionalization, too, demonstrates significant customer value, with APF F4-03 achieving a BCR of 0.95 and M4-03 achieving a BCR of 0.7 on the basis of resilience benefits. These outcomes are

sensitive to the assumption that CMI reduction benefits also flow to the feeder adjacent to the lines targeted for sectionalization (i.e., to which the candidate feeder is assumed to be tied). Guidehouse's distribution planning subject matter expert recommended that sectionalization benefits to adjacent feeders be de-rated by 50% for conservatism (e.g., to account for cases where adjacent feeders may not experience the same number of outages as the targeted feeder). If the adjacent feeder were assumed to achieve 80% (instead of 50%) of the reductions of the targeted feeder, the BCR for (for example) F4-02 would increase from 0.8 to 1.0.

The Voltage Conversion and Sectionalization RM exhibits even higher BCRs than the F-Class APFs for the Sectionalization RM. For this RM, however, the BCA includes only the incremental costs associated with sectionalization equipment – costs associated with the non-RM voltage conversion program are excluded. If non-RM costs were included, these would significantly reduce the BCR. For this RM, if there already exists a strong case to convert an F-Class feeder's voltage outside of the RM process, then, for many feeders, the incremental cost of installing the switches and reclosers necessary for sectionalization will also be cost-effective.

Finally, the analysis did not demonstrate the cost-effectiveness of Selective Undergrounding for average feeder sections for any of the APFs based on the resilience benefits quantified in the model. This outcome was largely driven by limitations in the available data granularity that result in understated benefits. For Clustered Hardening, Guidehouse was able to isolate the most vulnerable assets (poor condition poles) using condition assessment data. These poor condition poles could be modeled with failure thresholds reflecting their condition.

For this engagement, however, Guidehouse was not able to obtain data related to the highest-risk segments of overhead conductor – all overhead conductor within a given biome (as identified in its sub-class name, e.g., Farmland, Coniferous, Coniferous Deciduous Mix) on a given feeder shares the same probability of failure, making it difficult to differentiate where the benefits of undergrounding will be greatest. As a result, the quantified resilience benefits likely do not fully reflect the value that could be achieved through a targeted implementation of undergrounding (see the text box in the introduction to Section 5.2 for more details).

Conclusions

The VA has identified that from a forward-looking climate perspective, Hydro One's most vulnerable assets are located in its East region and, to a lesser extent, in the areas of the North and Central region nearest to the East region.

The subsequently-estimated set of BCAs have demonstrated that the implementation of resilience measures to mitigate against these vulnerabilities can deliver value to customers, even when consideration of benefits is limited mostly to resilience benefits. This value has been demonstrated to increase as the focus of the resilience measure is more tightly targeted to Hydro One's most vulnerable assets.

For some BCAs no additional distribution service benefits beyond those modeled are required to ensure that the investments are cost-effective. For other BCAs, achieving cost-effectiveness would require the application of either additional value streams to the analysis (e.g., reliability benefits) that are beyond the scope of this study, or a more targeted application of the investment to the most vulnerable portions of the system than could be modeled as part of this study.

The fact that some BCRs reach 1.0 based principally only on resilience benefits is a noteworthy outcome given the conservative modeling assumptions and inputs adopted by Guidehouse when addressing key uncertainties. In addition to accounting only for some of the customer benefits

(with normal reliability notably excluded), the analysis does not assume any growth in customer numbers over time and uses a unit value of lost load derived from the ICE calculator, which may understate the value of lost load in *force majeure* events.

Guidehouse has noted that the VASH analysis is an input to Hydro One's planning of resiliency investments. Guidehouse expects that, consistent with its treatment of other investment programs, Hydro One will continue to further analyze asset condition and system needs to refine the selection of projects for implementation. Guidehouse further expects that such planning activities undertaken by Hydro One will consider the full range of benefits these RMs offer and so ensure planners can identify projects and implement the opportunities that will provide the most value to customers.

Ways in which a targeted approach to asset and customer data collection as part of its resilience investment program will help Hydro One to identify projects most likely to deliver significant net customer benefits include:

- **Customer Data Collection.** Targeted collection of customer information associated with promising feeders or feeder segments could include:
  - *Feeder/Customer-Specific VoLL*. More precisely quantifying the value of lost load for specific customer segments or even individual customers will allow for a more accurate targeting of resilience measures to where they will deliver the most benefit. For example, quantifying the VoLL for critical loads, such as hospitals or water treatment facilities and for vulnerable customers (such as those in remote communities or in large multi-family buildings) may help to better target cost-effective resilience investments.
  - *Customer Growth*. Appropriately considering population growth projections, cross-referenced with regional planning assumptions for specific feeders (or feeder segments) of interest will help to more accurately quantify future resilience benefits in locations expected to experience significant load growth in the future.
- **Asset Engineering Data Collection and Analysis.** A focused assessment of specific assets on feeders or feeder segments by engineers and planners could more precisely identify:
  - *Addressable Vulnerabilities*. Considering vegetation or the surrounding conditions of a specific feeder segment as well as its location relative to the station and customers could allow engineers to more precisely identify assets most suitable for undergrounding. Such work would also allow planners to better quantify the value of this RM.
  - *Cost Efficiencies and Network Effects*. Evaluating costs on a more specific location-by-location basis can help identify opportunities to bundle or sequence infrastructure improvements efficiently across projects and bring down costs.
- **Comprehensive Assessment of Benefits.** A focus on a single primary value stream (resilience) is appropriate for a higher-level analysis like the VASH study, but site-specific assessments conducted as part of Hydro One's standard program implementation process should consider benefits comprehensively. Including consideration of reliability and other quantitative and qualitative benefits to customers will help to identify those opportunities for resilience measures that most drive value to Hydro One customers.

1.0 Introduction

In October of 2025, the Ontario Energy Board (OEB) published its *Vulnerability and System Hardening Report*.[11] This report articulated a Vulnerability and System Hardening (VASH) Framework, "*an OEB policy that outlines the OEB's expectations for the methodologies distributors use to identify parts of their systems that are most vulnerable to extreme weather and evaluate system hardening options based on an objective benefit-cost framework.*"

The Framework requires that all Ontario electricity distributors include a VASH analysis in rebasing applications submitted for 2028 rates. The Framework specifies that distributors are expected to integrate a VASH analysis in their Distribution System Plan (DSP).

Distributors are expected, as part of their VASH analysis, to complete a vulnerability assessment (VA), identifying parts of the distribution system most vulnerable to extreme weather and other climate-related events. After completing the VA, the OEB specifies that distributors should conduct a pre-assessment to determine whether technically and economically feasible system hardening investments exist. Where the pre-assessment identifies potentially suitable candidates for system hardening (or other) resilience investments, distributors are required to complete a benefit-cost analysis (BCA).

In February 2026, after a competitive procurement, Hydro One engaged Guidehouse to develop a VASH analysis as an input to its DSP to be included in its Joint Rate Application (JRAP). Hydro One identified five resiliency measure investments ("resiliency measures" or RM) that Guidehouse should, after completing the VA and pre-assessment steps, evaluate for cost-effectiveness using the BCA methods specified by the VASH Framework and the *Benefit-Cost Analysis Framework for Addressing Electricity System Needs*.[12] Guidehouse completed its analysis at the end of March 2026.

This report describes Guidehouse's approach and the findings of its VASH analysis.

1.1 Customized Generic Approach

The VASH Framework specifies that distributors may use either a custom or generic approach to completing the VASH analysis. To support distributors wishing to pursue the generic approach, the OEB has published an Excel-based model Toolkit intended to allow users to develop a VA for assets located within a single climate location, and a BCA for projects applied to the assets identified in the VA.

Guidehouse has elected to use the generic Toolkit, customized to meet the needs specific to Hydro One's VASH analysis. A VA workbook and five BCA workbooks (one for each RM quantitatively assessed for cost-effectiveness) accompany this report.

Although the Guidehouse team has made a number of specific modifications to the published toolkit, the workbooks all follow the same analysis logic as the Generic toolkit, applying the same key principles, including: asset classification, location-specific exceedance probabilities, and the calibration of expected outages to historically observed outages in a base year.

[11] Ontario Energy Board, *Vulnerability Assessment and System Hardening Report*; *EB-2024-0199 – Vulnerability Assessment and System Hardening (VASH) Project*, October 2025

Available at: https://engagewithus.oeb.ca/vulnerability-assessment-system-hardening

[12] Ontario Energy Board, *Benefit-Cost Analysis Framework for Addressing Electricity System Needs*, February 2026

Available at: https://engagewithus.oeb.ca/bcaframework

The analysis in these workbooks focuses on distribution feeder vulnerabilities of poles and conductor driven by high wind and freezing rain (ice accretion) climate perils, and on the potential for targeted investments to reduce asset failure risk, outage duration, and customer impacts.

1.2 Study Objectives and Scope

The goal of this study is to develop a VASH analysis for Hydro One in accordance with the OEB's VASH Framework. The study aims to complete three tasks:

- **Vulnerability Assessment.** Quantify the probability of asset failure through 2100 of conductor and pole assets as a result of exposure to wind and ice accretion climate perils, grouped by feeder type and climate location ("Feeder Archetypes"), and rank these Archetypes from most to least vulnerable.
- **Pre-Assessment.** Develop groupings of feeders based on their relative climate vulnerability, the potential cost to customers of extreme weather-driven "resiliency" outages, and their feasibility for the application of Hydro One's RMs.
- **Benefit-Cost Analysis.** Evaluate the cost-effectiveness, from the perspective of Hydro One's customers, of each of the RMs for each of the feeder groups identified in pre-assessment.

Resiliency vs. Reliability Outages

The BCA considers the cost to customers only of "resiliency" outages. These are defined as *force majeure* outages requiring the repair or replacement of the assets considered in the analysis.

In performing the BCAs for the five candidate RMs, Guidehouse evaluated resilience benefits – the benefits associated with reducing the frequency or criticality of *force majeure* outages.[13] Guidehouse's approach to calibrating projected outage frequency and quantifying the value of outages to customers deliberately excludes consideration of "normal" reliability outages. Any such reliability benefits that might be realized from the RMs modeled would be incremental to the benefits included in this analysis.

This VASH analysis is intended to act as an input to Hydro One's planning process. The VASH's Vulnerability Assessment provides a system-wide assessment of fragility which the Pre-Assessment and BCA leverage to develop a review of the overall resiliency improvement potential across the distribution network. This provides Hydro One planners with alternatives to consider as they prioritize investment and develop resilience improvement programs targeted to maximize the value to Hydro One customers.

1.3 Report Structure

The report is structured as follows:

- Section 2.0, **Vulnerability Assessment**, provides an overview of the methods and results of the vulnerability analysis of the Hydro One system to the climate perils considered.
- Section 3.0, **Resiliency Measure Descriptions**, introduces and describes the candidate resiliency measure (RM) investments, including defining some characteristics and RM assumptions that affect BCA results.

[13] Guidehouse understands that Hydro One uses the term *force majeure* to describe outages that the OEB refers to as the Major Events that are excluded from the calculation of Hydro One's RRR reporting reliability metrics. Guidehouse's reporting has adopted this term (*force majeure)* to be consistent with the naming conventions of its client.

- Section 4.0, **Pre-Assessment**, describes how Guidehouse grouped individual feeders based each on feeder's eligibility for each RM and its value-weighted vulnerability. This section describes the characteristics of the groupings and their impact on the BCA.
- Section 5.0, **Benefit-Cost Analysis**, describes the methods applied to perform the BCA for each feeder grouping and RM, summarizes the outcomes, and identifies some sensitivities of the results.

2.0 Vulnerability Assessment

This section describes the approach used by Guidehouse to develop the Hydro One VA within a modified version of the OEB's generic VA Toolkit (in Section 2.1) and the outcomes of that analysis (in Section 2.2).

2.1 VA Methods

Guidehouse quantified vulnerability on the Hydro One distribution feeders through a three-step process:

- Catalogue assets,
- Estimate fragility,
- Apply climate projections.

These three steps lead to a quantitative vulnerability ranking of the Hydro One distribution assets considered by this analysis, grounded in Hydro One data and informed by industry literature and expert feedback. Asset-level vulnerability scores can then be combined by feeder groupings to identify those sets of feeders most vulnerable to the climate perils considered.

As in the OEB's generic VA Toolkit, Guidehouse's VA scores asset vulnerability on the basis of each asset sub-class's probability of failure when exposed to the two climate perils. Feeder-level fragility (not included in the generic Toolkit) is assessed based on a weighted average of the individual asset sub-class probabilities of failure. Consistent with the OEB's generic VA Toolkit, the VA is agnostic to the *value* associated with the probability of asset failure (e.g., the value of lost load to customers associated with asset failure-driven outages). The customer value associated with feeder and asset fragility is considered as part of the pre-assessment and the BCA.

Each of the three steps noted above is briefly summarized below and then described in greater detail in the sections that follow.

Catalogue Assets

In this study, Guidehouse analyzed two asset classes: wood poles and overhead conductor (details of why these were selected are presented in Section 2.1.2.1, below). Assets were assigned into classes ("pole" and "conductor") and sub-classes. Sub-classes are defined to differentiate asset fragility or asset replacement cost as outlined in the OEB VASH Framework, e.g., "Wood Pole (Poor Condition) | Class 3 or Better | Coniferous | On-Road".

Guidehouse then assigned every Hydro One feeder to one of eight Feeder Groups, defined by the unique combination of feeder type (M- or F-Class) and Hydro One's four geographic regions: North, Central, South, and East. The count of assets by feeder within each feeder group was averaged to derive an average distribution of assets by sub-class per feeder within each feeder group.

Guidehouse mapped each Hydro One feeder to the 230 climate locations provided in the OEB's VA Toolkit for which a different projection of climate peril return intervals is available.[14] Each feeder is a member of one of the eight Feeder Groups and associated with one of the 230 climate locations. Each unique combination of Feeder Group and climate location is defined as a "Feeder Archetype". The outcome of the VA is to quantify the vulnerability of each asset sub-class by Archetype, and then further sort Archetypes from most to least vulnerable.

[14] Climate projections included by the OEB in its Toolkit are sourced from Environment and Climate Change Canada (ECCC).

Details for developing the catalogue of assets and Feeder Archetype may be found in Section 2.1.2.

Estimate Fragility

After cataloging assets into sub-classes that exhibit similar fragility characteristics, Guidehouse estimated failure thresholds for each sub-class. Failure thresholds are a key input to the vulnerability assessment and BCA process. Failure thresholds define the severity of a climate peril under which the given asset sub-class is assumed to fail, resulting in an outage. Estimated failure thresholds are developed based on industry asset fragility literature, informed by the experience of Hydro One staff.

The details of climate peril selection and the development of asset sub-class failure thresholds may be found in Section 2.1.3.

Apply Climate Projections

Climate projections drawn from the 230 available climate locations provided in the OEB generic VA tool (originating from Environment and Climate Change Canada – ECCC) are applied to the asset catalogue and estimated failure thresholds to derive asset probabilities of failure for each peril, at each location, for each year of the study period.

A weighted average of these probabilities is calculated for each Feeder Archetype and that is used to rank the vulnerability of the various Feeder Archetypes. These same asset failure probability values are then also used in the BCA, after having been calibrated against observed asset class-specific *force majeure* failures for the relevant individual feeders over the five-year period from 2021 through 2025.

The details of how the climate projections are applied to individual asset sub-classes and Feeder Archetype vulnerability is determined may be found in Section 2.1.4.

2.1.1 Data Sources

Guidehouse relied on the following data sources for the VA.

Table 2. Vulnerability Assessment Data Sources

Item	Source
Asset Type, Condition, Location	Hydro One
Projected Climate Data	OEB/ECCC/CSA[15]
Gust Conversion Factor	Durst Curve, Krayer et al.[16]
Pole Fragility Curves	Darestani and Shafieezadeh[17]
Pole Degradation Model	Shafieezadeh et al.[18]

[15] Ontario Energy Board. (2025). *Vulnerability Assessment Toolkit – October 7, 2025*. Vulnerability Assessment & System Hardening Project | Engage with Us

[16] Krayer, W. R., & Marshall, R. D. (1992). *Gust factors applied to hurricane winds*. **Bulletin of the American Meteorological Society, 73**(5), 613–618. https://doi.org/10.1175/1520-0477(1992)073<0613:GFATHW>2.0.CO;2

[17] Y. Mohammadi Darestani and A. Shafieezadeh, "Multi-Dimensional Wind Fragility Functions for Wood Utility Poles," Engineering Structures 183 (2019): 937–948. https://doi.org/10.1016/j.engstruct.2019.01.048

[18] A. Shafieezadeh, U. P. Onyewuchi, M. M. Begovic, and R. DesRoches, "Age-Dependent Fragility Models of Utility Wood Poles in Power Distribution Networks Against Extreme Wind Hazards," IEEE Transactions on Power Delivery 29, no. 1 (February 2014): 131–139, https://doi.org/10.1109/TPWRD.2013.2281265

Item	Source
Forestry Wind Damage	Freilich and Ostuno [19]
Sperry Piltz Ice Accumulation Index	National Weather Service [20]

2.1.2 Catalogue of Assets

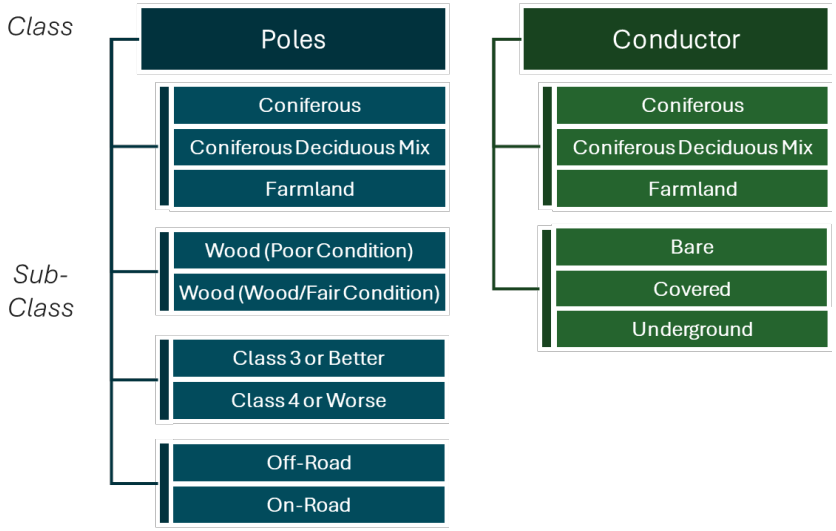
This section describes the process of cataloguing the asset classes and sub-classes considered in the analysis, grouping feeders by feeder class, Hydro One region, and climate location, and developing the Feeder Archetypes used to complete an assessment of feeder vulnerability across the Hydro One service territory.

2.1.2.1 Asset Classes and Sub-Classes

Guidehouse considered two asset classes in its VASH analysis: wood poles and conductor. These classes were selected in consultation with Hydro One on the basis that these were assets most susceptible to the climate perils included in this analysis. As described in Section 3.0 and Appendix C the "pole" asset class implicitly includes pole-top transformers, and the "conductor" asset class implicitly includes cross-arms. A review of the repair codes assigned to *force majeure* outages (once non-relevant cause coded outages – e.g., "Scheduled", "Human Element", etc. had been removed) showed that all such codes could be mapped to one of the two asset classes included, as they have been defined above.

Each class was further divided into a set of sub-classes, each sub-class defined to capture differing asset fragility (relevant to both VA and BCA) or replacement cost (relevant to the BCA only). Sub-classes are defined by the unique combination of sub-class characteristics, as illustrated in Figure 5.

Figure 5. Asset Sub-Class Characteristics



For example, one of the unique pole sub-classes is: "Wood (Good/Fair Condition) | Class 3 or Better | Coniferous | Off-Road".

[19] Frelich, L. E., and E. J. Ostuno. (2012). *Estimating wind speeds of convective storms from tree damage*. Electronic J. Severe Storms Meteor., 7 (9), 1–19.

[20] Sperry, S. (2014). *The SPIA Index™ (Sperry–Piltz Ice Accumulation Index)* [Conference presentation]. National Weather Service Integrated Warning Team (IWT) Workshop, Atlanta, GA. https://www.weather.gov/media/ffc/iwt2014/IWT2014_Sperry.pdf

The vegetation type sub-class characteristics are associated with specific Hydro One regions, as summarized in Table 3.

Table 3. Vegetation Characteristic / Region Mapping

Vegetation Type	Region
Coniferous	North
Coniferous Deciduous Mix	Central; East
Farmland	South

Guidehouse recognizes that assigning a single vegetation type to each region is a substantial simplification. Absent feeder-specific vegetation data, however, Guidehouse determined that applying vegetation assumptions at the region level was more appropriate than not addressing them at all.

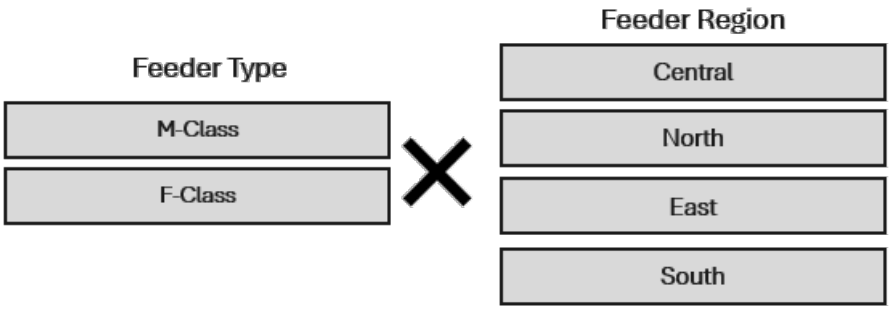
The comprehensive list of sub-classes may be found in Appendix A.

2.1.2.2 Feeder Groups

Hydro One provided Guidehouse with asset data for over 3,200 feeders in its service territory. These lines operate across a wide variety of voltages, from 4 kV to 44 kV. Feeders are divided into F-Class and M-Class feeders. M-Class feeders are generally (but not exclusively) higher voltage, often serving more or larger customers than F-Class feeders.

To manage the dimensionality of the VA, Guidehouse grouped feeders according to these two feeder classes. Guidehouse further grouped feeders according to the Hydro One region. This yields a set of eight Feeder Groups, as illustrated in Figure 6.

Figure 6. Feeder Groups



The distribution of individual feeders included in the analysis, and the average number of customers served by those feeders, by Feeder Group, is provided in Table 4. F-Class feeders may be downstream of M-Class feeders; customers served by M-Class feeders include both direct and downstream customers also served by F-Class feeders.

Table 4. Distribution of Feeders and Customers by Feeder Group

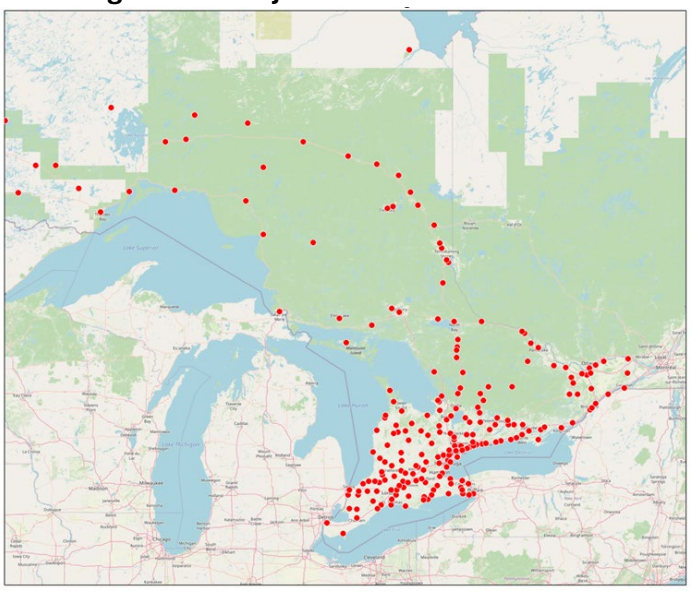
Feeder Group	Share of Feeders	Mean Customers Served per Feeder
F-Class Feeder | North	10%	508
F-Class Feeder | East	24%	493
F-Class Feeder | Central	25%	545
F-Class Feeder | South	22%	417
M-Class Feeder | North	2%	2,218
M-Class Feeder | East	3%	2,961
M-Class Feeder | Central	5%	3,067
M-Class Feeder | South	9%	1,407

2.1.2.3 Climate Locations

The generic Toolkit published by the OEB provides return intervals for wind and ice accretion climate perils through the year 2100 for 230 climate locations across Ontario. This geographic granularity is critical for differentiating the vulnerability of assets to projected climate perils across the province.

The geographic distribution of the 230 climate locations is illustrated on a map of Ontario in Figure 7.

Figure 7. Projected Climate Locations



Guidehouse mapped each feeder's ID[21] to the Geographic Information System (GIS) coordinates associated with the feeder head substation[22] and then used these coordinates to map each feeder

[21] Hydro One provided Guidehouse with a table identifying key feeder characteristics (e.g., kilometers of conductor off-road, operating voltage, etc.) The unique identifier for each feeder in this table is a five-digit number referred to by Hydro One as the Feeder ID.

[22] Hydro One provided GIS coordinates (latitude and longitude) of station names. These were mapped to individual Feeder IDs based on the feeder names included in the Feeder ID data set.

to one the climate locations. Of the 230 available climate locations, Hydro One feeders were mapped to 214.

2.1.2.4 Feeder Archetypes

Every feeder for which sufficient data was available to do so has been mapped to one of eight Feeder Groups. An average count of assets by sub-class per feeder is defined for each Feeder Group based on the average of the asset counts by sub-class of the feeders included in that Feeder Group. For all downstream analyses, the asset counts for each individual feeder are defined by the Feeder Group average.

Every feeder for which sufficient data was available to do so is likewise mapped to climate location. Climate peril return probabilities for each individual feeder are defined by those of the climate location to which that feeder is assigned.

These two groupings are combined to create Feeder Archetypes. A Feeder Archetype is defined by the unique combination of Feeder Group and climate location. For example, if there are four feeders mapped to the same climate location (e.g., Sudbury), and three belong to the F-Class North Feeder Group, and one belongs to the M-Class North Feeder Group, these are then divided into two Feeder Archetypes: "F-Class North | Sudbury" and "M-Class North | Sudbury".

The VA ranks the vulnerability of 327 Feeder Archetypes, representing over 3,200 individual feeders. There are on average nearly 10 feeders per Archetype, with some Archetypes representing more than 60 feeders and other Feeder Archetypes representing only a single feeder.

The use of Feeder Archetypes simplifies the interpretation of the VA by reducing the number of data points requiring review, while preserving the VA's most critical granularity: that of the climate locations and the differing climate peril return intervals at each one.

2.1.3 Estimate Fragility

Asset fragility is defined by the climate perils to which assets are subject, and the threshold of peril severity beyond which assets are assumed to fail and cause an outage. Asset failure thresholds are estimated for both baseline and resilience measure assets.

The two sections below describe the climate perils considered in this analysis, and the failure thresholds developed for the asset sub-classes.

2.1.3.1 Climate Perils

Guidehouse applied the projected wind and ice accretion data provided by the OEB, ECCC, and CSA in the VASH Toolkit to the Hydro One system. Wind and ice accretion projections are given at the 10-, 20-, 50-, 100-, and 200- year return intervals for 230 locations in Ontario for RCP 4.5, RCP 6.0, and RCP 8.5 climate scenarios defined below. A Representative Concentration Pathway (RCP) is a standardized greenhouse-gas concentration trajectory used in climate modeling that specifies radiative forcing levels (in watt/m^2) reached by the year 2100 relative to pre-industrial conditions. Each RCP is labeled by its approximate 2100 radiative forcing level – for example RCP 4.5 projects a total anthropogenic forcing of 4.5 watts/m^2 reached by 2100.

RCP Scenario Selection

Guidehouse used climate projections associated with Representative Concentration Pathway (RCP) 6.0. The OEB recommends "*aligning with the CSA approach of using RCP 8.5 for asset classes with expected useful lives less than 60 years and RCP 6.0 for asset classes with expected useful lives greater than 60 years.*"

Table 5 provides the accounting life for the asset classes considered, which align closely with the OEB bound of 60 years. The accounting life is derived from the annual depreciation values provided by Hydro One to Guidehouse and shown below in Table 6.

Table 5. Asset Accounting Life

Asset	Depreciation	Service (Accounting) Life (Years)	Service Life (Rounded)
Poles, Towers, and Fixtures	1.71%	58.48	60
Overhead Conductors	1.59%	62.89	65

Climate Action Tracker, an independent scientific project to track international government action on climate change, indicates in their November 2025 Warming Projections Global Update that based on current policies and actions expected warming in 2100 is 2.6 °C, while the Intergovernmental Panel on Climate Change (IPCC) projects 2081 to 2100 global warming levels associated with RCP 6.0 of 2.2 ± 0.5 °C, with 2081 to 2100 warming levels associated with RCP 8.5 of 3.7 ± 0.7 °C.[23, 24]

Based on the average asset life identified for each asset type above, and in consideration of the Climate Action Tracker projections noted above, Guidehouse chose to apply RCP 6.0 for this study.

Wind

High wind projections in OEB-provided climate data are given as 10-minute sustained values. This is a standard unit of wind measurement although different from that used by much of the available asset fragility literature, which often uses 3-second gust speeds. To ensure alignment between climate data projections and asset failure thresholds, Guidehouse applied a standard gust conversion factor based on the Durst curve to convert gust speeds to 10-minute sustained wind speeds.[25]

For a 10-minute to 3-second conversion, this corresponds to an approximate gust factor of 1.48, e.g., a 100 km/h 10-minute sustained wind speed is estimated to record 3-second gusts of approximately 148 km/h.

Ice Accretion

Freezing rain ice accretion is a complex climatic process, requiring the simultaneous presence of precipitation, a warm upper atmosphere, and sub-freezing surface temperatures to result in ice accumulation on exposed infrastructure.

ECCC classifies freezing rain ice accretion as a Tier 3 climate variable, indicating relatively low confidence and limited supporting research compared to more commonly modelled hazards such

[23] Climate Action Tracker. (2025, November). Warming Projections *Global Update – November 2025*. https://climateactiontracker.org/documents/1348/CAT_2025-11-13_GlobalUpdate_COP30.pdf

[24] Collins, M., R. Knutti, J. Arblaster, J.-L. Dufresne, T. Fichefet, P. Friedlingstein, X. Gao, W.J. Gutowski, T. Johns, G. Krinner, M. Shongwe, C. Tebaldi, A.J. Weaver and M. Wehner, 2013: Long-term Climate Change: Projections, Commitments and Irreversibility. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[25] Krayer, W. R., & Marshall, R. D. (1992).

as wind.[26] As a result, ECCC projections focus exclusively on the projected amount of ice accretion, expressed in millimeters at various return intervals, and do not provide any assumptions or quantification of concurrent wind conditions during freezing rain events.

Because of these limitations in the projected freezing rain ice accretion data, Guidehouse has – for modeling purposes - assumed that wind speeds are less than 25 km/h during freezing rain ice accretion events. This assumption reflects the absence of a scientific basis for modelling joint wind/ice hazard conditions using ECCC data. Guidehouse believes this to be a conservative assumption which likely leads to an under-quantification of ice-related risk to the Hydro One distribution system and thus will understate benefits associated with resilience measures intended to address this climate peril. Analysis of observed wind speeds during major historical ice accretion events may be found in Section B.3.

2.1.3.2 Failure Thresholds

Guidehouse developed asset failure thresholds to translate projected climate peril into asset-specific probabilities of failure suitable for long-term planning. Thresholds are grounded in asset characteristics, asset condition, peer-reviewed engineering literature, and industry endorsed planning tools, while maintaining consistency with the resolution and limitations of ECCC climate projections. Where quantitative fragility curves were available from academic and industry literature, primarily for pole wind loading, these were applied directly to derive failure thresholds. Where such fragility literature was limited, Guidehouse applied a qualitative, impact-based approach informed by industry indices, engineering standards, and engineering judgement, as described below.

Wind

For the high wind hazard, Guidehouse prioritized widely cited fragility models that explicitly represent distribution assets. Pole wind failure thresholds were derived from published fragility curves to represent the onset of meaningful structural failure and service disruption rather than minor repairable damage.[27] Pole strength was differentiated by class and condition, with an age-based degradation model used as a proxy for the condition categorization of “Good/Fair” or “Poor” condition provided by Hydro One.[28]

Wind speeds given in Darestani and Shafieezadeh were converted to 10-minute sustained values using a Durst curve to align with ECCC projections.[29] To reflect Hydro One’s experience with vegetation driven pole failures, pole wind thresholds were then capped based on regional vegetation characteristics with appropriate vegetation damage caps sourced from academic forestry literature on expected tree damage at various wind speeds.[30]

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[26] Cannon, A. J., Jeong, D. I., Zhang, X., & Zwiers, F. W. (2020). *Climate-resilient buildings and core public infrastructure 2020: An assessment of the impact of climate change on climatic design data in Canada*. Environment and Climate Change Canada. https://publications.gc.ca/collections/collection_2021/eccc/En4-415-2020-eng.pdf

[27] Y. Mohammadi Darestani and A. Shafieezadeh, “Multi-Dimensional Wind Fragility Functions for Wood Utility Poles,” Engineering Structures 183 (2019): 937–948. https://doi.org/10.1016/j.engstruct.2019.01.048

[28] A. Shafieezadeh, U. P. Onyewuchi, M. M. Begovic, and R. DesRoches, “Age-Dependent Fragility Models of Utility Wood Poles in Power Distribution Networks Against Extreme Wind Hazards,” IEEE Transactions on Power Delivery 29, no. 1 (February 2014): 131–139, https://doi.org/10.1109/TPWRD.2013.2281265

[29] Krayer, W. R., & Marshall, R. D. (1992).

[30] Frelich, L. E., and E. J. Ostuno. (2012)

This approach ensures pole failure is governed by the dominant failure mode: direct structural wind loading for poor condition poles and secondary vegetation fall-in for poles with significant wind resistance. Pole wind thresholds are provided in Table 6.

Table 6. Pole Wind Thresholds

Sub Class	10-Minute (km/h)	Equivalent 3-Second Gust (km/h)
Class 3 or Better | Good | Farmland	167.1	247.3
Class 3 or Better | Good | Coniferous	122.6	181.4
Class 3 or Better | Good | Coniferous Deciduous Mix	128.0	189.4
Class 3 or Better | Poor | Farmland	104.9	155.3
Class 3 or Better | Poor | Coniferous	104.9	155.3
Class 3 or Better | Poor | Coniferous Deciduous Mix	104.9	155.3
Class 4 or Worse | Good | Farmland	140.2	207.5
Class 4 or Worse | Good | Coniferous	122.6	181.4
Class 4 or Worse | Good | Coniferous Deciduous Mix	128.0	189.4
Class 4 or Worse | Poor | Farmland	88.0	130.2
Class 4 or Worse | Poor | Coniferous	88.0	130.2
Class 4 or Worse | Poor | Coniferous Deciduous Mix	88.0	130.2

For conductor wind thresholds, Guidehouse assumed failures are driven directly or indirectly[31] by vegetation contact rather than direct wind loading. This assumption was developed after review of academic literature that suggests conductors exhibit very high wind tolerance and direct conductor failure from wind alone is unlikely.[32] Therefore, Guidehouse relied on the same forestry source used to cap pole thresholds to assign region-specific failure thresholds to conductor tied to the wind speeds at which large branches break, trees are uprooted, or trunk failure is expected.

Higher thresholds were applied in farmland areas with limited vegetation exposure, while covered conductors were assigned higher thresholds in forested regions to reflect improved resistance to branch contact. Underground conductors were assumed to exhibit no wind related failures. Table 7 provides the assigned conductor wind thresholds.

Table 7. Conductor Wind Thresholds

Sub-Class	10-Minute (km/h)	Equivalent 3-Second Gust (km/h)
Bare | Farmland	112.8	166.9
Bare | Coniferous Deciduous Mix	89.5	132.5

[31] For example mechanical loading of conductor due to vegetation fall-in causing deteriorated cross-arms to fail.

[32] Ma, L., P. Bocchini, and V. Christou. 2020. "Fragility models of electrical conductors in power transmission networks subjected to hurricanes." Structural Safety. Vol. 82:101890.

Sub-Class	10-Minute (km/h)	Equivalent 3-Second Gust (km/h)
Bare | Coniferous	87.9	130.1
Covered | Farmland	119.3	176.6
Covered | Coniferous Deciduous Mix	98.7	146.1
Covered | Coniferous	94.4	139.7
Underground | Farmland	-	-
Underground | Coniferous Deciduous Mix	-	-
Underground | Coniferous	-	-

Ice Accretion

For freezing rain ice accretion thresholds, Guidehouse relied on an industry damage index, observed outcomes of prior ice accretion events, and judgement due to the limited quantitative fragility literature and lower confidence in projected joint wind and ice conditions as described in Section 2.1.3.

Ice accretion thresholds were informed by the Sperry-Piltz Ice Accumulation (SPIA) Index and observed outcomes of previous major ice accretion events in Ontario. The SPIA Index is reproduced in Table 8. This index was developed specifically to assess potential utility system damage resulting from freezing rain events and has been endorsed by the National Association of Regulatory Utility Commissioners (NARUC) for planning purposes.[33]

Table 8. Sperry-Piltz Ice Accumulation Index[34] for Wind Speeds Below 24.1 km/h

Ice Damage Index	Average Ice Amount	Damage and Impact Description
0	< 6.35 mm	Minimal risk of damage to exposed utility systems; no alerts or advisories needed for crews, few outages.
1	6.35 mm – 12.7 mm	Some isolated or localized utility interruptions are possible, typically lasting only a few hours. Roads and bridges may become slick and hazardous.
2	12.7 mm – 18.05 mm	Scattered utility interruptions expected, typically lasting 12 to 24 hours. Roads and travel conditions may be extremely hazardous due to ice accumulation.
3	18.05 mm – 25.4 mm	Numerous utility interruptions with some damage to main feeder lines and equipment expected. Tree limb damage is excessive. Outages lasting 1-5 days.

[33] Board of Directors of the National Association of Regulatory Utility Commissioners, *Resolution Supporting the Sperry-Piltz Ice Accumulation Index (SPIA Index)*

Available at : http://pubs.naruc.org/pub/53A0CCE6-2354-D714-51B2-A032B9278E53

[34] Sperry, S. (2014). *The SPIA Index™ (Sperry–Piltz Ice Accumulation Index)* [Conference presentation]. National Weather Service Integrated Warning Team (IWT) Workshop, Atlanta, GA. https://www.weather.gov/media/ffc/iwt2014/IWT2014_Sperry.pdf

Ice Damage Index	Average Ice Amount	Damage and Impact Description
4	25.4 mm – 38.1 mm	Prolonged & widespread utility interruptions with extensive damage to main distribution feeder lines & some high voltage transmission line/structures. Outages lasting 5-10 days.
5	>38.1 mm	Catastrophic damage to entire exposed utility systems, including both distribution and transmission networks. Outages could last several weeks in some areas. Shelters needed.

Pole ice failure thresholds vary by pole class and condition, with the same degradation assumptions used to account for pole condition as used for wind failure thresholds. Pole ice failure thresholds are (like pole wind thresholds) capped based on vegetation to reflect the failure of assets due to extensive vegetation damage at high levels of ice accretion. Pole ice thresholds are provided in Table 9.

Table 9. Vegetation-Informed Pole Ice Accretion Thresholds

Sub-Class	Ice Threshold (mm)
Wood (Good/Fair Condition) | Class 3 or Better | Coniferous	30.2
Wood (Good/Fair Condition) | Class 3 or Better | Coniferous Deciduous Mix	31.8
Wood (Good/Fair Condition) | Class 3 or Better | Farmland	44.7
Wood (Good/Fair Condition) | Class 4 or Worse | Coniferous	30.2
Wood (Good/Fair Condition) | Class 4 or Worse | Coniferous Deciduous Mix	31.6
Wood (Good/Fair Condition) | Class 4 or Worse | Farmland	39.8
Wood (Poor Condition) | Class 3 or Better | Coniferous	28.1
Wood (Poor Condition) | Class 3 or Better | Coniferous Deciduous Mix	28.1
Wood (Poor Condition) | Class 3 or Better | Farmland	28.1
Wood (Poor Condition) | Class 4 or Worse | Coniferous	25.0
Wood (Poor Condition) | Class 4 or Worse | Coniferous Deciduous Mix	25.0
Wood (Poor Condition) | Class 4 or Worse | Farmland	25.0

Conductor ice thresholds were aligned with vegetation damage descriptions in the SPIA Index, with no increase in strength assigned to covered conductor based on the assumption that the larger wire diameter-driven increased ice load would offset improved resistance to ice-driven vegetation impacts. Conductor ice thresholds are provided in Figure 10.

Table 10. Vegetation Informed Conductor Ice Accretion Thresholds

Sub-Class	Ice Threshold (mm)
Bare - Suitable for Undergrounding | Coniferous	18.1
Bare | Coniferous Deciduous Mix	21.8
Bare | Farmland	25.4
Covered | Coniferous	18.1
Covered | Coniferous Deciduous Mix	21.8
Covered | Farmland	25.4

Sub-Class	Ice Threshold (mm)
Underground | Coniferous	-
Underground | Coniferous Deciduous Mix	-
Underground | Farmland	-

2.1.4 Apply Climate Projections

This section describes how the climate exceedance probabilities – the probability in any given year that the severity of each climate peril will exceed the failure threshold of a given asset – are developed and applied to individual asset sub-classes and then aggregated to deliver a ranking of Feeder Archetype vulnerability.

2.1.4.1 Estimate Climate Exceedance Probabilities

Following assignment of asset failure thresholds, Guidehouse used ECCC projected climate data to derive the projected probability of exceeding the assigned thresholds for each climate location, in each year and for each climate scenario. These are the exceedance probabilities that are used to quantify the probability of an asset in a given sub-class failing in any given year.

Projected ECCC climate data for wind and freezing rain ice accretion is provided in the OEB's Toolkit in the form of return intervals. Return intervals define discrete points along a climate peril probability curve and provide the probability of occurrence associated with peril intensity, e.g., a 1:100-year return interval corresponds to 1% annual probability of occurrence. ECCC data includes the 1:10-, 1:20-, 1:50-, 1:100-, and 1:200-year return intervals corresponding to 10% to 0.5% annual probability of occurrence.

To construct a continuous view of hazard probability, Guidehouse interpolates the points along the climate hazard curve to allow for sampling at the relevant asset hazard thresholds. This interpolation is performed for each location, year, and climate scenario using a log-linear interpolation to align with the log-linear shape of the tail of a climate hazard distribution.[35] The probability of exceeding a specified intensity threshold H is then given by

Equation 1 | Probability of Exceedance

$$P_{exceedance} = 10^{-\left(log_{10}(R_L)+\frac{H-I_L}{I_U-I_L}(log_{10}(R_U)-log_{10}(R_L))\right)},$$

where R_L is the return period lower bound, R_U is the return period upper bound, I_L is the peril intensity at R_L, and I_U is the hazard intensity at R_U.

Although for this work Guidehouse scripted the estimation of exceedance probabilities (to more quickly generate the required volume of outputs), the output of this work delivers the same result as that included in the "3. Climate Severity Calculator" of the generic OEB Toolkit.

2.1.4.2 Estimating Asset and Feeder-Level Vulnerability

Asset-level vulnerability by sub-class in any given year for a given climate location is calculated as the sum of the ice and wind exceedance probabilities specific to that sub-class's failure threshold. This implicitly assumes the independence of the climate perils, the same logic as used in the OEB's generic Toolkit.

[35] Electric Power Research Institute, *Fragility Curves for Quantifying Physical Climate Risk in the Electric Power Sector*, 2025 Available here: https://www.epri.com/research/products/000000003002031792.

This provides an uncalibrated[36] probability of failure for each sub-class by Feeder Archetype (i.e., by unique combination of Feeder Group and climate location), delivering a heatmap of asset fragility across the entirety of Hydro One's service territory. This is simply an expanded version of the heatmap included in the generic OEB Toolkit, modified to include multiple climate locations.

To assist with the interpretation of VA results and their use as part of the pre-assessment, the Guidehouse team aggregated asset-sub-class results to the Feeder Archetype level. Each Feeder Archetype is given a vulnerability score, a normalized weighted average of the uncalibrated sub-class failure probabilities, by Feeder Archetype. Conductor and pole classes are weighted equally, and sub-class weights are applied on the basis of sub-class asset counts within each asset class (by Feeder Archetype).

This provides a score allowing Guidehouse to output a relative ranking of Feeder Archetype vulnerability from the most to the least vulnerable, based on distribution of the fragility of the assets and the severity of the climate perils to which the Archetypes are projected by the ECCC to be exposed. This score is output in intervals of five years. For the purposes of ranking the vulnerability of the Feeder Archetypes, Guidehouse has used the simple average VA score across the period of analysis.

2.2 VA Results

This section provides the results of Guidehouse's vulnerability assessment. The goal of this section is to show the feeder groupings – the Feeder Archetypes - in Hydro One territory that are projected to exhibit the greatest vulnerability to climate hazards in the future. This ranking of Feeder Archetypes is determined by the fragility of the assets and the projected severity of the climate perils to which they are exposed. These rankings are value-agnostic and take no account of the relative impact that such fragility may have on customers.

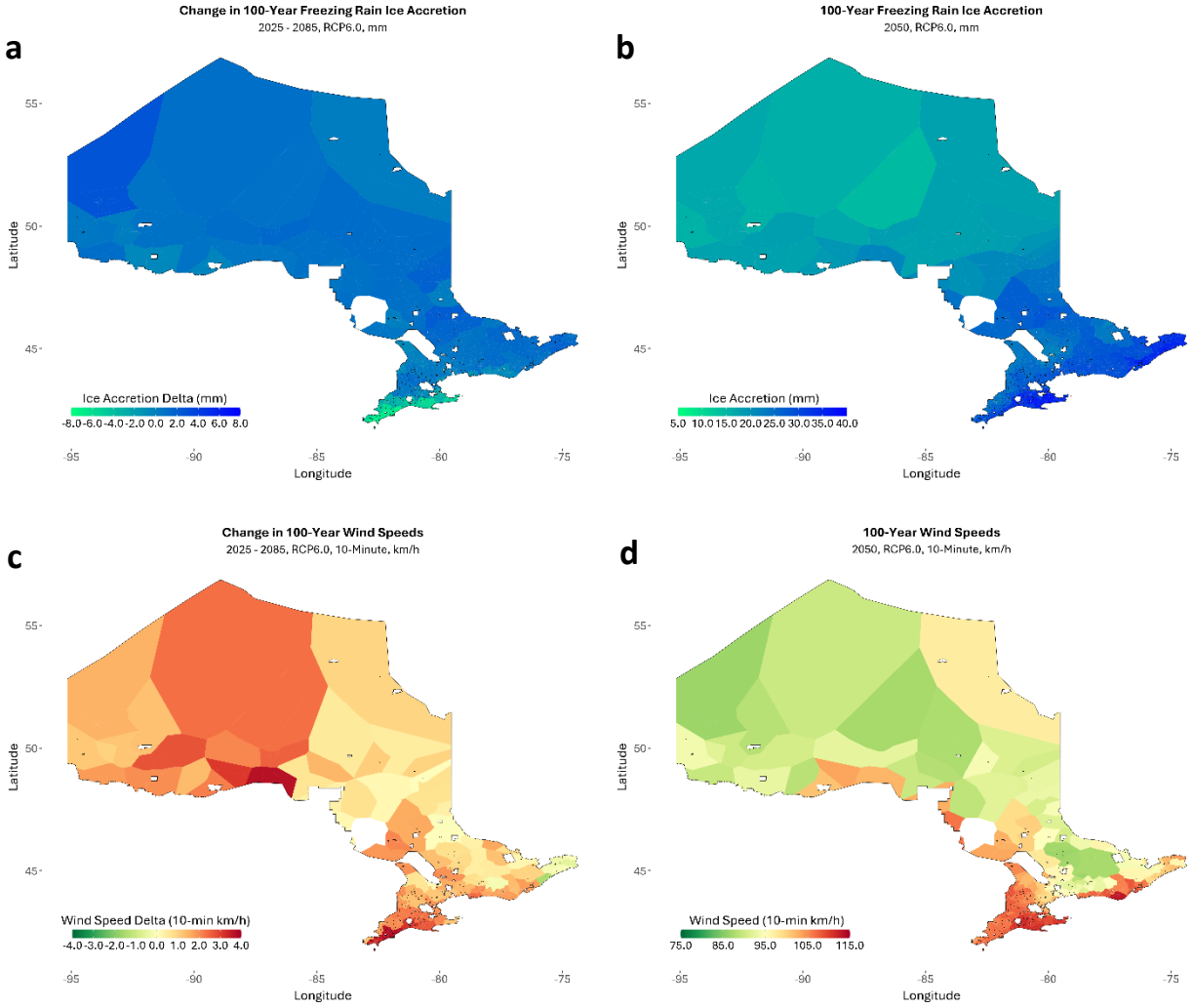
Consideration of where feeder vulnerability is likely to most materially impact customer costs is accounted for in the pre-assessment and BCA tasks. This section is divided into three. The first section provides a high-level overview of the evolving severity of the climate perils across Ontario. The second section briefly summarizes the uncalibrated vulnerability of different asset classes. The third section maps the relative vulnerability of the Feeder Archetypes across Hydro One's territory and identifies the regional distribution of the most and least vulnerable Feeder Archetypes, determined based on the metrics applied in this analysis.

2.2.1 Provincial Climate Exposure

The evolving provincial climate exposure to high wind and ice accretion events is essential context for interpreting asset- and Feeder Archetype-level vulnerability rankings. Figure 8 shows the projected *change* in 100-year ice accretion and wind speeds in the period from 2025 to 2085 (panel a and c). Panels b and d show the 2050 point-estimate of projected severity of 100-year ice accretion and wind speeds (panel b and d), all under RCP 6.0.

[36] Although the VA is based purely on forward-looking exceedance probabilities, the BCA, under the generic Toolkit method, calibrates asset probabilities of failure to historical observed outages in a calibration (base) year.

Figure 8. Projected High Wind and Ice Accretion Events under RCP 6.0



Projected climate data in Hydro One territory under RCP 6.0 for 1-in-100-year events. a) Projected change in 100-year freezing rain ice accretion events from 2025 to 2085 (mm). b) 2050 projected 100-year freezing rain ice accretion (mm). c) Projected change in 100-year wind speeds from 2025 to 2085 (km/h). d) 2050 projected 100-year wind speeds (km/h).

As seen in panel b, ice accretion is projected to be most severe in the most easterly part of the province along the Ottawa to Kingston corridor, and quite severe in the near-north close to North Bay and Sudbury as well as on the western shore of Lake Ontario, near Hamilton. With climate change, however, exposure to ice accretion in the southern region is projected to decline as temperatures warm (panel a), leading to a northward shift in the occurrence of freezing rain events.[37] With that shift, the central and northern regions are projected to see a rise in ice accretion increasing feeder vulnerability in that region in the future.

Wind speeds are projected to be most extreme on the eastern shores of Great Lakes, as shown in panel d. The most extreme wind speeds are projected to occur in the same Kingston / Cornwall region in which ice accretion is projected to be greatest. Wind speeds in 100-year events are

[37] D. I. Jeong, A. J. Cannon, and X. Zhang, "Projected Changes to Extreme Freezing Precipitation and Design Ice Loads over North America Based on a Large Ensemble of Canadian Regional Climate Model Simulations," Natural Hazards and Earth System Sciences 19 (2019): 857–872, https://doi.org/10.5194/nhess-19-857-2019

projected (see panel c) to grow relatively less (on a percentage basis) than ice accretion as global temperatures rise from 2025 to 2085, but to experience the most significant relative growth in on the north and eastern shores of Lake Superior.

The south-easterly-most region of the province is also projected to experience material growth in exposure to extreme wind. This is, however, a region of the province with much less tree coverage than those in the north and east projected to be exposed to the most extreme winds.

2.2.2 Asset Vulnerability

The "5.1 VA Heatmap" tab included in the VA workbook submitted with this report can provide a comprehensive of uncalibrated[38] failure probabilities for each asset sub-class. This section provides a summary of some of the total (sum of ice accretion and wind-based) failure probabilities by asset class and location, as well as some additional context for interpreting these results.

Table 11 provides weighted average individual uncalibrated asset class failure probabilities for M-Class and F-Class feeder assets by region for 2035.

Table 11. Asset Class Average Uncalibrated Failure Probabilities

Asset Class	Region	F-Class	M-Class
Pole	North	0.0023	0.0034
Pole	East	0.0158	0.0217
Pole	Central	0.0079	0.0070
Pole	South	0.0090	0.0089
Conductor	North	0.0704	0.1037
Conductor	East	0.1376	0.1930
Conductor	Central	0.0900	0.1069
Conductor	South	0.0501	0.0639

Some the key features of this summary that stand out: conductor tends to be much more vulnerable than poles, the East region tends to be more vulnerable than other regions, and M-Class feeder assets (in particular conductor) appear in some cases to be more vulnerable than F-Class feeders.

Conductor is more vulnerable than pole for two reasons: although in vegetated areas (e.g., with coniferous or coniferous and deciduous mix of vegetation) conductor is approximately as vulnerable as poles are to wind, conductor is *much* more vulnerable to ice accretion than poles. This is particularly true in the more heavily vegetated areas of Hydro One's service territory.

The East region is more vulnerable than the others because it is in this region in particular that both wind *and* ice accretion perils are most extreme. The East is, likewise, more vegetated than the South (where wind is also severe) and is becoming more vulnerable to ice accretion over time, unlike the South which is becoming less so.

[38] As part of the BCA, failure probabilities for a given feeder or group of feeders are calibrated to historical observed *force majeure* outages driven by the associated asset class (conductor or pole). One important effect of this calibration step is to align near-term expected outages with historically observed outages, implicitly correcting for the joint probabilities of asset failure, which are not modeled.

Finally, conductor on M-Class feeders is on *average* more vulnerable than F-Class feeders simply by virtue of the fact that a higher proportion of M-Class feeders are located in regions projected to experience the most extreme weather. In the East region, for example, there are both M-Class and F-Class feeders in climate locations with severe wind projections (e.g., Kingston, Cornwall, Napanee, Norwood, etc.) along the Ottawa/Kingston and Ottawa/Highway 7 corridors. By contrast more northerly parts of the East region (e.g., climate locations such as Bancroft, Killaloe, Stirling, and Deep River) are served primarily by F-Class feeders. These more remote and northerly parts of the East region are projected by the ECCC to be subject to much less severe climate perils; lower winds, and less ice accretion than those areas nearer Lake Ontario.

2.2.3 Feeder Archetype Vulnerability

To move from asset fragility to feeder fragility, the results of the asset level failure probability calculation are rolled up to Feeder Archetypes. To do so, Guidehouse calculates a Feeder Archetype fragility score that is a weighted average of uncalibrated asset probabilities of failure, as described in Section 2.1.4.2.

Figure 9 shows the vulnerability of F- and M-Class feeders at the Feeder Archetype level across the service territory in 2030 (panel a and c, the top and bottom quadrants on the left of the figure) and 2085 (panel b and d, the top and bottom quadrants on the right of the figure). These reflect the application of geographically evolving severity of the climate perils illustrated in Section 2.2.1, the asset failure thresholds discussed in Section 2.1.3.2, and the relative distribution of assets within the Feeder Groups.

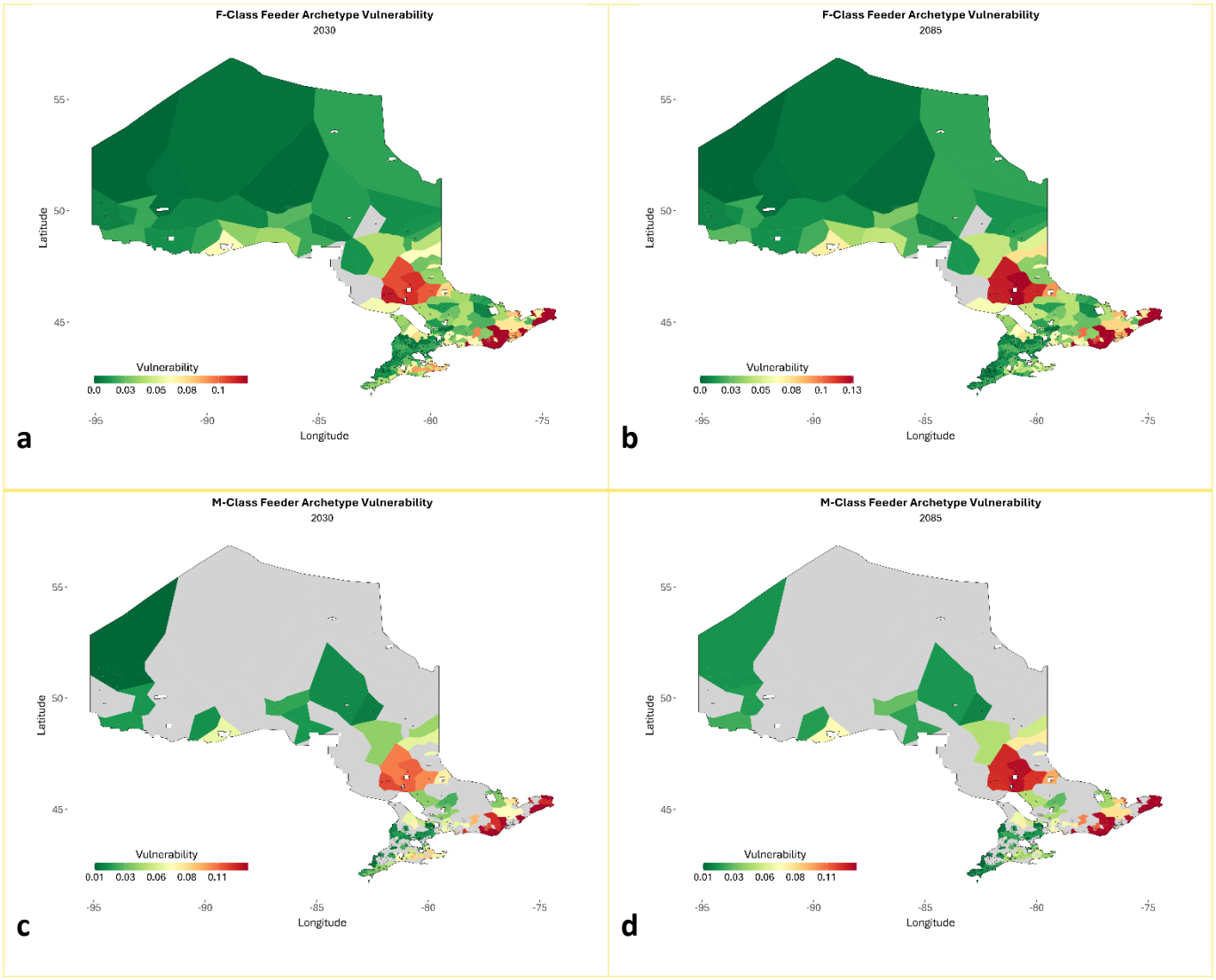
Both F- and M-Class feeders in the East region exhibit the highest relative climate vulnerability, clustered in the region in which both ice accretion and wind speeds are projected to be most severe. Despite exposure to comparable projected wind severity, the South region is shown to be relatively less vulnerable at present – shown in panels a and c - because of differences in vegetation and becoming less vulnerable over time -as shown in panels b and d - as the severity of ice accretion is projected to migrate north in the later periods.

Those Central region Feeder Archetypes that are most vulnerable are for the most part those clustered on the north-eastern shores of Lake Ontario, in the climate regions of Port Hope and Oshawa. [39] These regions have high projected exposure to both freezing rain ice accretion and high wind speeds, along with relatively more vulnerable assets than those in the South region due to vegetation.

The notable vulnerability of Feeder Archetypes in the near-North region (in the climate regions of Sudbury, North Bay, and Espanola) are principally a reflection of the ice accretion peril severity, which is projected to increase materially in this region, and the impact of this increasing severity on vegetation around the assets.

[39] Hydro One distribution feeder heads (transformer stations) were mapped to climate locations (geographic regions to which a given set of climate projections apply) using GIS data. Guidehouse understands that climate location names (e.g., Port Hope and Oshawa) refer to the location of the weather station providing the historic data used by ECCC to develop the climate projections for that region. Hydro One distribution assets may fall within climate locations named after towns (e.g., Oshawa) that are not directly served by Hydro One's distribution network.

Figure 9. Relative Vulnerability of F- and M-Class Feeder Groups in 2030 and 2085 under RCP 6.0



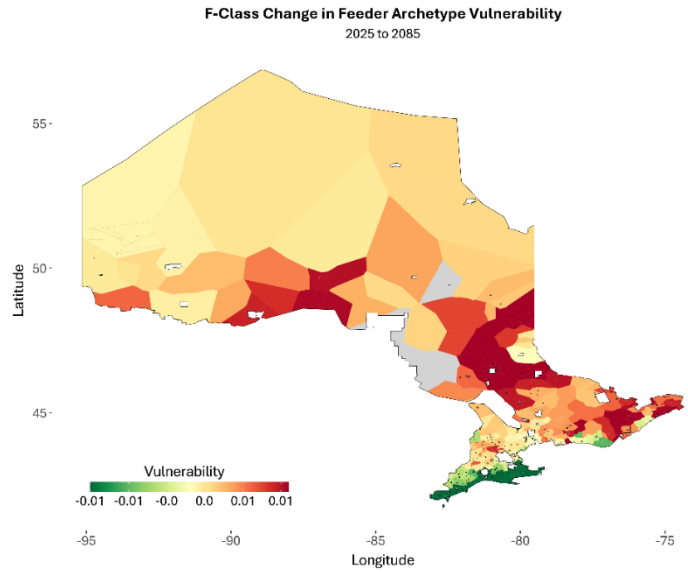
Relative vulnerability of F- (panels a and b) and M-Class (panels c and d) Feeder Groups in 2030 and 2085 under RCP 6.0. Feeders are mapped to the substation at the head, gray areas indicate no mapped substation. a) 2030 F-Class vulnerability. b) 2085 F-Class vulnerability. c) 2030 M-Class vulnerability. d) 2085 M-Class vulnerability.

Figure 10 shows the change in vulnerability for F- and M-Class feeders from 2025 to 2085 under RCP 6.0. The most distinctive features of these plots are the projected increase in vulnerability in the North region, as ice accretion risk from freezing rain events increases, and the increase in vulnerability in the already-vulnerable East, which is projected to experience an increase in the severity of both wind and ice accretion events.

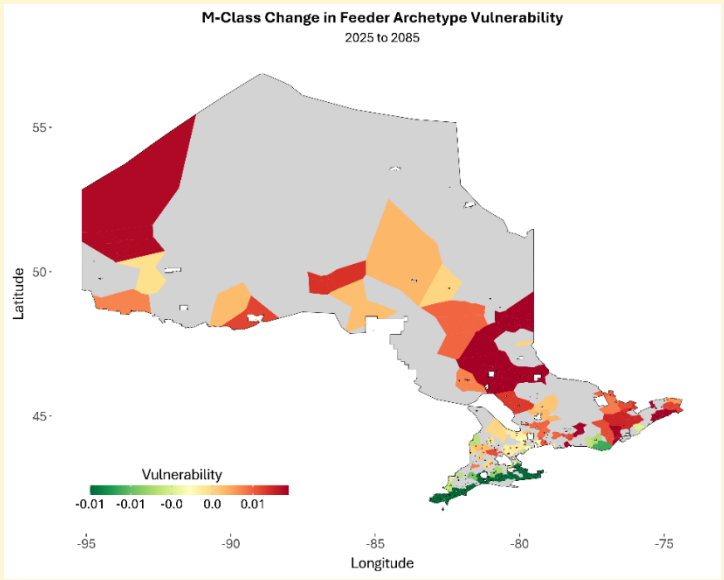
Conversely, projected reduction in ice accretion events in the South, which disproportionately affect conductor assets, meaningfully lowers the vulnerability of this region over time.

Figure 10. Change in F- and M-Class Vulnerability, 2025 to 2085, RCP 6.0

A



B



Change in vulnerability of F- (panel a) and M-Class (panel b) Feeder Groups from 2025 to 2085 under RCP 6.0. Feeders are mapped to the substation at the head, gray areas indicate no mapped substation. a) Change in F-Class vulnerability. b) Change in M-Class vulnerability.

Table 12 provides the distribution of the top 20% of Feeder Archetypes determined to be most vulnerable using the metrics specified above, by feeder class and region. These identify the most vulnerable sets of assets over the projection period. As would be expected based on the geographic distribution of projected climate peril severity, the East region accounts for more than

half of these most vulnerable Archetypes. In contrast only 5% of the most vulnerable F-Class Feeder Archetypes and none of the M-Class Feeder Archetypes are from the South region.[40]

Table 12. Distribution of Top 20% (Most) Vulnerable Feeder Archetypes

		Feeder Class	
		F-Class	M-Class
Region	North	20%	27%
	East	54%	59%
	Central	22%	14%
	South	5%	0%

Table 13 provides the distribution of the bottom 20% of Feeder Archetypes determined using the metrics specified above, by feeder class and region. These identify the least vulnerable sets of assets over the projection period. This distribution, like that of the most vulnerable Feeder Archetypes, reflects the relative fragility of the assets as a result of regional vegetation and the declining projected severity of ice accretion events in the South.

Table 13. Distribution of Bottom 20% (Least) Vulnerable Feeder Archetypes

		Feeder Class	
		F-Class	M-Class
Region	North	23%	13%
	East	5%	0%
	Central	0%	0%
	South	72%	87%

[40] The two South Feeder Archetypes falling in the top 20% most vulnerable include the Nanticoke and Haldimand (Caledonia) climate locations, on the north-eastern shore of Lake Erie.

3.0 Resiliency Measure Descriptions

To improve the resilience of its distribution system to extreme climate events, Hydro One is considering five climate mitigation and resilience measures (RMs). These RMs are designed to reduce the frequency of outages due to asset failures or the duration of outages when assets do fail.

The five RMs that Hydro One identified for Guidehouse to consider in its analysis are:

1. **Clustered Hardening.** The replacement of poor condition poles on vulnerable feeders.
2. **Covered Conductor.** Covering segments of conductor on highly vegetated or otherwise vulnerable feeders.
3. **Selective Undergrounding.** Undergrounding strategically chosen segments of conductor on highly vegetated or otherwise vulnerable feeders.
4. **Sectionalization.** Sectionalization schemes to add switches to better isolate faults and reduce restoration times.
5. **Voltage Conversion & Sectionalization.** The application of sectionalization schemes to feeders where voltage conversion is applied. This RM considers only the incremental benefits and costs of sectionalization, assuming the voltage conversion occurs as part of the baseline scenario.

Guidehouse's analysis of these RMs considers the resilience benefits they offer customers. Assessments of avoided outages or reduced outage duration that drive most of the benefits consider only *force majeure* (resilience) events. Guidehouse's analysis does not include any value associated with any improvement in normal reliability (i.e., non-*force majeure* events) that these RM may offer in addition to their resilience benefits. A complete description of the value streams considered in the BCA may be found in Section 5.0.

Each of the sections below provides a summary of the key characteristics of each RM reflected in Guidehouse's modeling. *The purpose of this section is to provide reviewers with a transparent understanding of what was (or was not) modeled for each RM*, and not to provide a comprehensive or detailed description of equipment, assets, or methods employed in implementing the given resilience measure.

The determination of the feeders to which these RM may be applicable is addressed in the Pre-Assessment discussion in Section 4.0. More details on cost assumptions may be found in Appendix C.

3.1 Clustered Hardening

Measure Description. The replacement of poor condition poles on the targeted feeder. The replacement pole is expected to be a higher class (stronger/taller) than the existing pole, with attendant (where relevant) necessary modifications to conductor hardware, such as insulators or brackets.

For modeling purposes, Guidehouse has assumed the RM replaces all poor condition "Class 4 or Worse" poles with "Class 3 or Better" sub-class poles. Poor condition "Class 3 or Better" poles are assumed to be replaced on a like-for-like basis.

Project Lifetime. Consistent with the accounting service life of poles of 60 years (see Table 5) the period of analysis applied to this RM is 60 years.

Baseline Description. In the absence of the RM, poor condition poles are assumed to be refurbished or replaced in 10 years, on average. This baseline assumed period of remaining operation prior to replacement (as part of existing Hydro One processes) is referred to as the poles' remaining *operating* life (ROL – see text box at right). Baseline replacement is assumed to be like-for-like (e.g., Class 4 or Worse poles are replaced by Class 4 or Worse poles). Hydro One has identified that approximately 70% of poles are refurbished (30% replaced) at end of life, and that the cost of refurbishment is approximately 20% that of replacement.

Existing Asset ROL. Poor condition poles are assumed to have an ROL of ten years, as per Hydro One. This indicates that Hydro One would expect that any given poor condition pole on its system would be refurbished or repaired on average in 10 years from the base year, absent the resilience measure.

Project Benefits. Modeled benefits derive from

- *Outage Frequency Reductions*. The impact on customer value of lost load (VoLL) from a reduction in the frequency of outages due to the improvement in asset resilience from a comparison of:
  - the existing asset to the RM replacement asset (during the existing asset's remaining operating life – ROL),
  - the standard (baseline replacement) asset and the RM replacement asset (after the expiry of the existing asset's ROL).
- *Avoided Repair and Replacement*. The probability-weighted avoided cost of replacing poles damaged during *force majeure* events that have been replaced by more resilient poles. Hydro One has identified that pole replacement in the aftermath of *force majeure* events should be assumed to cost approximately 2.7 times as much as when replacement is planned.

Project Costs.

- *Incremental Cost*. All RM costs are modeled on a per pole basis and include the replacement cost for the pole itself and the cost of required line transformers. Modeling assumes that for every four poles replaced, one line transformer must be replaced. Costs differ depending on the class of pole (Class 3 or Better vs. Class 4 or Worse), and pole accessibility (off-road vs. on-road).
- *Early Retirement Cost Adjustment*. Consistent with the OEB Toolkit logic, the RM asset cost is adjusted to reflect the fact that some baseline asset cost would otherwise have been incurred at the end of the existing asset's ROL. This means that the incremental RM asset cost is less than the total cost of the RM assets. See Section 5.1.4 for more details.

Remaining Operating Life (ROL)

The OEB's VASH Framework defines the remaining useful life (RUL) as:

> *"…the number of years these assets would have continued to be in service if the resiliency project had not been implemented."*

Guidehouse's analysis uses this variable as the OEB has defined it but refers to it as the remaining operating life (ROL) instead of RUL.

This is done to avoid confusion with the definition of RUL employed by Hydro One.

The OEB defines RUL as the number of years the asset would remain in use, absent the resiliency project, irrespective of that asset's condition or its typical useful life.

Hydro One defines RUL as the absolute number of remaining years of an asset's projected service life (depreciation period).

An asset may have RUL = 0 but ROL >0

To avoid confusion with Hydro One's definition of remaining useful life Guidehouse has slightly adjusted the name of this term and refers to it in this report as "remaining operating life" or ROL.

3.2 Covered Conductor

Measure Description. On average 3 km of conductor on the targeted feeder is assumed to be covered. This action provides increased resistance to faults caused by tree branch contact, reducing the likelihood of phase-to-ground faults resulting from incidental vegetation contact during high wind events.

Project Lifetime. Consistent with the accounting service life of conductor of 65 years (see Table 5) the period of analysis applied to this RM is 65 years.

Baseline Description. In the absence of the RM bare conductor is assumed to be replaced like-for-like by bare conductor at the end of its remaining useful life.

Existing Asset ROL. Hydro One has indicated that covered conductor would be deployed to replace bare conductor that would otherwise be expected to be replaced in, on average, 10 years. The BCA uses an ROL of 10.

Project Benefits. Modeled benefits derive from

- *Outage Frequency*. The impact on customer VoLL from a reduction in the frequency of outages due to the improvement in asset resilience from a comparison of the baseline bare conductor to the RM replacement covered conductor.
- *Avoided Repair and Replacement*. The cost of repairing conductor failures during *force majeure* events that would be avoided by replacing the bare conductor with the covered conductor. Hydro One has identified that the cost of conductor repair in the aftermath of *force majeure* events should be assumed to include only the cost of repairing cross-arms, but that the cost of such repairs should be assumed to be approximately 5.5 times higher than when the replacement of cross-arms is planned.

Project Costs. All RM costs are modeled on a per conductor km basis.

3.3 Selective Undergrounding

Measure Description. Between 1 and 3 km of conductor on the targeted feeder is assumed to be undergrounded. Hydro One staff have specified the length of conductor for each feeder that could be undergrounded and have noted that the length undergrounded may reflect several spans located in different areas along the feeder.

Undergrounding eliminates the contribution to probability-weighted outages by the length of conductor replaced (and by the corresponding share of poles) that are replaced by the undergrounded line.

Project Lifetime. Hydro One uses a depreciation rate of 2.52% for underground conductor, indicating a rounded accounting life of 40 years, which is used as the period of analysis for this RM.

Baseline Description. In the absence of the RM, bare conductor is assumed to be replaced like-for-like by bare conductor at the end of its remaining useful life.

Existing Asset ROL. Hydro One has indicated that undergrounding would be deployed to replace bare conductor (and the associated poles) that would otherwise be expected to be replaced in, on average, 10 years. The BCA uses an ROL of 10.

Project Benefits. Modeled benefits derive from

- *Outage Frequency*. The impact on customer VoLL from a reduction in the frequency of outages due to the improvement in asset resilience from a comparison of the baseline bare overhead conductor and baseline poles to the RM replacement underground conductor.
- *Avoided Repair and Replacement*. The cost of repairing conductor and pole failures during *force majeure* events that would be avoided by replacing the bare conductor and poles with the underground conductor. Avoided repair and replacement costs of poles and conductors align with those of the previous two RMs.
- *Reduced OM&A Costs*. Undergrounding conductor means that expenses associated with vegetation control over the underground segment can be eliminated, assumed to be $8,200 per year, per kilometer of right-of-way undergrounded.

Project Costs. All RM costs are modeled on a per conductor km basis.

3.4 Sectionalization

Measure Description. Sectionalization schemes will be applied to targeted feeders, adding switches to isolate faults within a feeder and to tie the targeted feeder to an adjacent feeder, reducing average outage durations on both the targeted and adjacent feeder.

Project Lifetime. Guidehouse has assumed a project lifetime of 40 years for this RM on the basis of the assumption that this is the approximate lifetime of a switch.

Baseline Description. This is a pure retrofit project (as per the definition of such under VASH Framework) which does "not impact existing assets" – the baseline would simply be status quo operation.

Existing Asset ROL. N/A. This is a Retrofit, not an Early Retirement RM.

Project Benefits. Modeled benefits derive from

- *Outage Criticality on the Targeted Feeder*. Hydro One has estimated that sectionalization of F-Class feeders will yield a reduction in outage duration of 15 – 20% for F-Class feeders, and 30 – 40% for M-Class feeders. Guidehouse has, accordingly assumed that this RM will reduce customer minutes interrupted (CMI) per outage by 17.5% for F-Class feeders and 35% for M-Class Feeders.
- *Outage Criticality on the Adjacent Feeder*. Sectionalizing schemes with tie transfer capability of the targeted feeder to an unfaulted segment of the adjacent feeder will also provide CMI per outage benefits to the adjacent feeder when it experiences faults on main line sections. Due to uncertainty as to the degree to which the adjacent feeder will benefit, Guidehouse has assumed that CMI reductions for the adjacent feeder are half of those of the targeted feeder (e.g., an 8.75% reduction in CMI per outage for F-Class feeders).

Guidehouse did not model a change in the frequency of outages to reflect the likelihood of outage occurrence on main feeder sections (trunk lines) vs lateral lines, as Hydro One provided Guidehouse with an estimate of outage duration reduction for all outages for a given feeder. In other words, Hydro One's estimated outage duration reduction implicitly includes consideration for trunk vs lateral outages.

Project Costs.

- *Capital Costs*. Hydro One has directed Guidehouse to assume that the cost of sectionalization of
  - F-Class feeders will be the cost of three switches (to sectionalize the target feeder) plus one additional switch to tie the target feeder to the adjacent feeder, with 1 to 2 poles (1.5 for modeling purposes) replaced per sectionalization location (switch).
  - M-Class feeders will be the cost of an average of 4.5 switches (to sectionalize the target feeder) plus one additional switch (to tie the target feeder to the adjacent feeder), with same pole assumption as the F-Class feeder sectionalization.
- OM&A Costs. Hydro One has directed Guidehouse to assume an annual incremental OM&A cost of $5,000 per F-Class and $7,500 per M-Class feeder that is sectionalized.

3.5 Voltage Conversion & Sectionalization

This RM is modeled identically to the Sectionalization RM, though it is applied to a different set of candidate feeders (see Section 4.0, below). This RM is assumed to be applied to feeders that have already undergone voltage conversion. The benefits and costs modeled for this RM are therefore incremental to (and do not include) any of the direct costs or benefits associated with voltage conversion itself.

Guidehouse understands that this RM is intended to opportunistically target feeders where the voltage is being converted to the same as that of nearby or adjacent feeders, allowing for sectionalization benefits to both the target and adjacent feeder.

The list of candidate feeders provided by Hydro One includes only to F-Class feeders.

4.0 Pre-Assessment

The OEB's VASH Framework requires electricity distributors to complete and submit a pre-assessment of potential resilience measure projects informed by the findings of the VA. The purpose of the pre-assessment is to identify candidate projects where the value to customers may then be more rigorously evaluated using the BCA.

The guidance provided by the VASH Framework for completing the pre-assessment includes:

- **Using the VA to Prioritize.** Per the Framework, distributors may: "*Prioritize their analysis on the most significant vulnerabilities identified in the VA.*"

  Guidehouse has used the vulnerability ranking of the Feeder Archetypes output of the VA as part of the pre-assessment (see Section 4.2)

- **Integrating Historical Data.** Per the Framework, distributors may: "*Leverage historical data and operational experience to identify areas of the system that have experienced repeated or severe impacts from extreme weather events.*"

  Guidehouse has applied historical interruption data from *force majeure* events for individual feeders to the ranked list of Feeder Archetypes to develop a ranked list of "most vulnerable" feeders for use in the pre-assessment (see Section 4.2)

- **Considering Geography, Technical Feasibility, and Other Relevant Information.** Per the Framework, distributors may: "*Assess the results of the VA in conjunction with other relevant information, such as… alignment with other capital plans (e.g., system renewal or grid modernization. Consider geographic and environmental factors…* [and] *the technical feasibility of system hardening solutions.*"

Hydro One staff have contributed to the pre-assessment by identifying candidate feeders based on their operational experience, on geographic and environmental factors specific to the RM under consideration, and in alignment with other capital plans, as per the guidance of the Framework.

The Guidehouse team has contributed to the pre-assessment by cross-referencing these feeders against a ranked list of individual feeders indicated by the VA to be most vulnerable to the climate perils under consideration and indicated by historical outage data to be most vulnerable to *force majeure* events impacting the assets under consideration. This ranking is described in more detail in Section 4.2, below.

The result of this pre-assessment is to create a set of three "average program feeders" (APFs -see text box below for more details) for each class of feeder and each RM to allow Guidehouse to evaluate BCAs for each RM across groups of feeders with varying levels of vulnerability to the climate perils.

The APFs are different from the eight Feeder Groups developed for the VA. The eight Feeder Groups (identified by region and feeder class) used in the VA are a *comprehensive* allocation of all feeders to distinct geographic groups.

APFs are *not* intended to be comprehensive but represent a targeted sub-set of feeders for which the benefits and costs of a given RM may be assessed. The output of the pre-assessment is a set of 27 APFs; three F-Class and three M-Class APFs for four of the RMs and three F-Class APFs for the Voltage Conversion and Sectionalization RM (which is applicable only to F-Class feeders).

Section 4.2 describes how Guidehouse used the Feeder Archetype vulnerability ranking, individual customer counts, and historical outage data to create a ranked list of the most vulnerable *individual* feeders. Section 4.3 discusses the pool of candidate feeders identified by Hydro One staff for consideration for each RM. Section 4.4 defines the characteristics of the APFs, and how the data from individual feeders is combined to create the APF. Section 4.5 provides some of the key characteristics of the APFs used in this analysis.

The "Average Program Feeder" - APF

APFs are a critical conceptual component of the pre-assessment and the BCA.

The BCA for each resilience measure is assessed for a set of APFs whose characteristics are averages of the characteristics of as many as 2,600, or as few as 30, feeders.

APFs, rather than individual feeders or feeder segments, are used in the BCA to simplify the potential quantification of *aggregate* RM benefits. APFs enable, per Section 5.2 of the VASH Framework, the use of "*a single BCA… to support a program intended to address multiple, similar needs that may exist at different locations within the distribution system.*"

4.1 Data Sources

Guidehouse relied on the following data sources for the pre-assessment.

Table 14. Pre-Assessment Data Sources

Item	Source
Historical Force Majeure Outage Data by Feeder (Customers Impacted, Duration, Frequency)	Guidehouse analysis of Hydro One outage management system (OMS) interruption data
Connected Customers by Feeder	Hydro One
RM Feeder Candidates	Hydro One

4.2 Individual Feeder Resilience Ranking

As part of the pre-assessment, Guidehouse developed a ranking of individual feeder level vulnerability by applying historical outage data and the number of customers served by a feeder to each feeder's Feeder Archetype vulnerability score.

This process provides a ranked list of F-Class and M-Class feeders, allowing Guidehouse to evaluate BCAs (for example) of the top 50 most vulnerable feeders compared to the top 300 most vulnerable feeders.

In this context, some nuance is required in defining what is meant by "most vulnerable". Vulnerability, under the VA logic published in the OEB Toolkit, is purely a measure of relative asset fragility when subjected to the projected climate perils. In the VASH Framework's VA context, when one asset has a higher projected probability of failure than another then that asset is more vulnerable than the second, even if the first asset serves only a single customer and the second serves a thousand. The VA is, by design, agnostic to customer value as measured by VoLL.

The purpose of the pre-assessment, however, is to narrow the focus of the analysis to those assets where a resiliency measure project is most likely to deliver customer value (i.e., test as cost-effective under the BCA). As part of the pre-assessment, therefore, Guidehouse ranked individual feeders by applying a customer-weighted vulnerability metric developed as a function of historical

outages and feeder customer counts to the Feeder Archetype vulnerability score. This implicitly applies some assumption of value. For example, all else equal, if two feeders share a same Feeder Archetype (and thus have assets that share the same probability of failure), the feeder that serves more customers will be considered "more vulnerable".

In all remaining discussions of the pre-assessment or BCA, when reference is made to a group of feeders' relative vulnerability, this should be understood to be the implicitly value-weighted vulnerability developed in the pre-assessment.

The section below describes the mechanics of *how* the individual feeder ranking was performed. The section after that describes the reasoning for *why* the ranking method used was selected.

4.2.1 Individual Feeder Vulnerability Ranking Method

The customer-weighted vulnerability metric used to rank individual feeders from most to least vulnerable is calculated by multiplying each feeder's[41] corresponding Feeder Archetype vulnerability score by a customer metric, as shown below,

Equation 2 | Weighted Vulnerability

$$Vulnerability_{customer\ weighted} = C \cdot Vulnerability_{unweighted}$$

Where

C is a customer count metric, defined below, and

$Vulnerability_{unweighted}$ is the feeder vulnerability score inherited from the Feeder Archetype level.

The customer count metric is calculated as:

Equation 3 | Customer Count Metric

$$\mathrm{C} = \mathrm{w} \cdot Cust_{historical} + (1 - w) \cdot Cust_{connected}$$

Where

$Cust_{historical}$ is the average number of customers impacted by pole or conductor-related *force majeure* outages occurring from 2021 through 2025,

$Cust_{connected}$ is the total number of customers connected to the given feeder, and

$w = 0.5$. The reasoning for the use of this value is explained in the section below.

The application of the customer-weighted vulnerability metric to the Feeder Archetype vulnerability score is then used to rank individual feeders from most vulnerable (highest score) to least vulnerable (lowest score).

The customer counts (and number of customers impacted by *force majeure* events*)* used for calculating this metric are a simple count of customers, undifferentiated by customer class.[42]

[41] Each individual feeder can be mapped to a single Feeder Archetype.

[42] Feeder-level customer class distributions were not available to Guidehouse as part of this analysis.

4.2.2 Reasoning for Ranking Method

The pre-assessment combines two complementary sources of information: historical customer impacts observed during *force majeure* events and potential future customer impacts derived from forward-looking peril analysis. Incorporating historical performance captures feeder-level vulnerabilities that cannot be resolved in a purely forward-looking assessment due to the spatial and temporal limitations of the available climate data.

This approach avoids overfitting vulnerability estimates to historical events, which represent only a single realization of a chaotic and probabilistic weather system. Relying too heavily on historical performance can understate the vulnerability of feeders that avoided recent outage impacts by chance, while an exclusively forward-looking approach ignores valuable information about how the system performed during recent extreme events.

Guidehouse's methodology balances these limitations by integrating both historical and potential future impacts into a single, comparable, customer impact weighted vulnerability metric for ranking feeders. An equal weight ("w" in the equation above) of 0.5 was selected to provide equal weight to historical customer outages and future outage exposure based on the total number of customers connected to the feeder.

This ranking is intended to provide Guidehouse with a dimension (e.g., "top X most vulnerable feeders") that can be used for filtering feeders for inclusion in the APFs that will be tested in the BCA. For example, if the average feeder (APF) reflecting the average characteristics[43] of the top 500 most vulnerable feeders is not a cost-effective target for the implementation of a resilience measure, then perhaps the APF reflecting the average characteristics of the top *200* most vulnerable feeders is.

The ranked list of feeders developed as part of the pre-assessment provides a tool for testing the sensitivity of the aggregate system benefit of the resilience measure in question to the relative vulnerability of the feeders to which the RM is applied.

4.3 Resilience Measure Candidate Feeders

APFs were defined for most RMs as the intersection of the "top X most vulnerable feeders" and of the set of candidate feeders for each RM, defined by Hydro One staff.[44] Table 15, below, provides the count of candidate feeders identified by Hydro One for each RM.

[43] The three main sets of APF characteristics that drive BCA results are described in Section 5.5

[44] Counts of candidate feeders in the table include only those feeders for which Guidehouse had sufficient data to include in the analysis.

Table 15. Count of Candidate Feeders Identified by Hydro One

Resilience Measure	# Candidate F-Class Feeders	# Candidate M-Class Feeders	Notes
1. Clustered Hardening	All	All	Hydro One did not provide a targeted list of candidates for these RMs. All feeders were treated as potential candidates for inclusion in these RMs' APFs
2. Covered Conductor	All	All	
3. Selective Undergrounding	348	102	Hydro One staff identified the length of feeder segment that (for modeling purposes) would assumed to be undergrounded, between 1 and 3 km. Hydro One staff have noted to Guidehouse that these lengths have been provided to Guidehouse for the purposes of the VASH analysis and will be further refined when analyzing specific feeders as candidates for selective undergrounding. .
4. Sectionalization	79	173	
5. Voltage Conversion and Sectionalization	1,156	0	

APFs were then developed for each RM as the intersection of candidate feeders identified by Hydro One staff, and the most vulnerable feeders ranked by Guidehouse (using the ranking described in Section 4.2, above).

For example, for the Selective Undergrounding resilience measure (RM number 3) there are three F-Class APFs:

- F3-01: Includes all undergrounding F-Class feeder candidates.
- F3-02: Includes the 80 most vulnerable of the undergrounding F-Class feeder candidates.
- F3-03: Includes the 30 most vulnerable of the undergrounding F-Class feeder candidates.

4.4 Defining Average Program Feeders (APFs)

The cost-effectiveness of each RM is assessed through the application of a BCA to each of the APFs assigned to the corresponding RM. APFs are averaged feeders intended to provide a representative analysis that is easily scalable up to match the aggregate value an RM offers, if it were applied to all feeders included in an APF.

Each APF has three primary sets of characteristics:

- **Asset Counts**: Counts of assets per feeder by Sub-Class. Asset counts are inherited from the corresponding Feeder Archetype used in the VA. Put another way, each individual feeder is assumed to have the same asset counts as the Feeder Archetype average.

  The APF's asset count by sub-class is an average of the sub-class asset counts assigned to each individual feeder within the APF. Sub-class asset counts are assigned to an individual feeder from that feeder's corresponding Feeder Archetype.

- **Climate Peril Exceedance Probabilities**: The probability in any given year of the severity of a given climate peril exceeding the failure threshold of a given asset sub-class. Climate exceedance probabilities are inherited from the corresponding Feeder Archetype used in the VA.

  The APF's exceedance probability by asset sub-class and year is an average of the exceedance probabilities assigned to each individual feeder within the APF. Sub-class exceedance probabilities are assigned to an individual feeder from that feeder's corresponding Feeder Archetype.

- **Impact Parameters and Calibration Factors**: The average number of *force majeure* outages per year (attributable to poles, conductor, or both, depending on the RM), and the average number of CMI per outage experienced by customers served by the feeder over the previous five years. These values are *not* inherited from the Archetypes and are specific to the individual feeders in the analysis. These values are essential for calibrating the base year outage frequency of the APF and for determining the customer value of lost load per outage.

  The APF's average outages per year is sum of the individual feeder outages per year, divided by the number of feeders included in the APF. The APF's average CMI per outage is the sum of individual feeder CMI per year divided by the total number of feeder outages per year.

In the BCA, the combination of asset counts and exceedance probabilities provides an expected number of outages per year under both the expected baseline and the resilience measure scenarios. The historically observed number of outages per year are compared to this projected expected value (in the base – or calibration – year) to deliver a calibration ratio. This calibration ratio is applied to projected expected outages in all future years. This ensures that trending changes in outage probabilities (which may grow over time as the severity of the climate perils increases) are tied back to observed history in the base year.

This third set of characteristics is, therefore, critical to projected outcome of the BCA. Calibration is addressed in greater detail in Section 5.1.

4.5 APF Characteristics

Table 16 provides a summary of the 27 APFs used in the BCA. For most resilience measures six APFs are defined: three F-Class and three M-Class. The Voltage Conversion and Sectionalization RM applies only to F-Class feeders, so only three APFs are included for this RM.

The Guidehouse team defined the APFs based on how many of the most vulnerable candidate feeders were included. The number of most vulnerable feeders included in each APF by RM was selected to provide a range of BCA outcomes for each RM. The first APF for each class and RM combination (e.g., F1-01) includes all candidate feeders. In the case of Clustered Hardening and Covered Conductor, this included *all* feeders for which Guidehouse had sufficient data to include in the analysis.

For RMs for which Hydro One had provided a list of candidates, the first APF (e.g., F4-01 for the Sectionalization RM) includes all possible candidate feeders. For each subsequent APF within a given RM (e.g., F1-02 and F1-03 for Clustered Hardening) the Guidehouse team included a progressively smaller number of feeders from the top of the list of most vulnerable feeders to demonstrate a range of BCR outcomes. The expectation is that the BCA ratio of each APF should improve as the group of feeders included in the APF progressively excludes the less vulnerable feeders.

That is, there is an expectation that (for example) Clustered Hardening would be more cost-effective if applied to the 65 most vulnerable feeders than if applied to the 850 most vulnerable feeders. Table 16 provides the feeder count for each APF.

Table 16. APF Summary

APF ID	Feeder Class	Program Name	Feeder Count
F1-01	F	Clustered Hardening	2,600
F1-02	F	Clustered Hardening	850
F1-03	F	Clustered Hardening	65
M1-01	M	Clustered Hardening	622
M1-02	M	Clustered Hardening	500
M1-03	M	Clustered Hardening	125
F2-01	F	Covered Conductor	2,600
F2-02	F	Covered Conductor	850
F2-03	F	Covered Conductor	125
M2-01	M	Covered Conductor	622
M2-02	M	Covered Conductor	500
M2-03	M	Covered Conductor	125
F3-01	F	Selective Undergrounding	348
F3-02	F	Selective Undergrounding	80
F3-03	F	Selective Undergrounding	50
M3-01	M	Selective Undergrounding	102
M3-02	M	Selective Undergrounding	75
M3-03	M	Selective Undergrounding	30
F4-01	F	Sectionalization	79
F4-02	F	Sectionalization	50
F4-03	F	Sectionalization	30

APF ID	Feeder Class	Program Name	Feeder Count
M4-01	M	Sectionalization	173
M4-02	M	Sectionalization	100
M4-03	M	Sectionalization	30
F5-01	F	Voltage Conversion & Sectionalization	1,156
F5-02	F	Voltage Conversion & Sectionalization	200
F5-03	F	Voltage Conversion & Sectionalization	100

Table 17 provides the distribution of feeders by Hydro One region. As APFs become progressively smaller within a given RM, the share of feeders they include that are located in the East region grows, and the share of feeders in the South region shrinks. This is consistent with the findings of the VA (which identified feeders in the East as relatively more vulnerable, and feeders in the South as relatively less vulnerable), and the approach for selecting feeders into each APF, described above.

Table 17. Regional Distribution of APF Feeders

APF ID	North	East	Central	South
F1-01	13%	30%	31%	27%
F1-02	14%	52%	30%	5%
F1-03	18%	65%	17%	0%
M1-01	10%	18%	24%	49%
M1-02	11%	20%	24%	45%
M1-03	9%	50%	36%	5%
F2-01	13%	30%	31%	27%
F2-02	14%	52%	30%	5%
F2-03	24%	63%	13%	0%
M2-01	10%	18%	24%	49%
M2-02	11%	20%	24%	45%
M2-03	9%	50%	36%	5%
F3-01	1%	34%	65%	0%
F3-02	5%	78%	18%	0%
F3-03	8%	74%	18%	0%
M3-01	0%	28%	56%	16%
M3-02	0%	36%	59%	5%
M3-03	0%	60%	37%	3%
F4-01	48%	22%	20%	10%
F4-02	44%	22%	26%	8%
F4-03	43%	30%	20%	7%
M4-01	9%	17%	16%	59%
M4-02	10%	25%	14%	51%
M4-03	17%	47%	23%	13%
F5-01	0%	27%	33%	40%
F5-02	0%	81%	18%	2%
F5-03	0%	83%	17%	0%

The historical average number of outages per year, and the average CMI per outage for each APF are critical inputs to the BCA. The average historical outages per year are used to calibrate the forward-looking expected value (probability-weighted) average number of outages per year, and the CMI per outage values are used to quantify the benefits to customers of either reducing the frequency of outages (Clustered Hardening, Covered Conductor, Selective Undergrounding) or reducing the criticality (duration) of outages (Sectionalization, and Voltage Conversion and Sectionalization).

Table 18 provides the values of these parameters for each APF, and identifies whether these are pole-only outage impacts, conductor-only outage impacts, or both types of outage impact. Outage types (pole or conductor) are determined in the OMS data based on the repair description field.

The type of outages (and CMI per outage) considered for each APF was determined based on the assets the corresponding RM was set to address. Clustered Hardening is a pole-replacement RM,

so only pole-based *force majeure* outages are considered. Covered Conductor is a conductor-replacement RM, so only conductor-based outages are considered.

The outage data used to calculate the values in the table below includes only *force majeure* events (filtered by Hydro One) and excludes events with the "Scheduled", "Human Element", "Loss of Supply", or "Foreign Interference" cause codes.

Table 18. APF Impact Parameters and Calibration Factors

APF ID	Outages Per Year	CMI Per Outage[45]	Outage Type
F1-01	0.155	214,182	Pole
F1-02	0.237	270,885	Pole
F1-03	0.397	328,678	Pole
M1-01	0.057	965,839	Pole
M1-02	0.071	965,839	Pole
M1-03	0.050	4,002,626	Pole
F2-01	0.401	189,247	Conductor
F2-02	0.616	213,842	Conductor
F2-03	0.718	199,815	Conductor
M2-01	0.080	535,748	Conductor
M2-02	0.100	535,748	Conductor
M2-03	0.078	1,817,018	Conductor
F3-01	1.806	295,203	All
F3-02	2.160	257,135	All
F3-03	2.120	271,910	All
M3-01	0.322	1,485,618	All
M3-02	0.248	2,129,635	All
M3-03	0.220	3,978,350	All
F4-01	0.425	257,600	All
F4-02	0.568	297,785	All
F4-03	0.687	293,827	All
M4-01	0.075	454,935	All
M4-02	0.114	517,718	All
M4-03	0.087	2,032,845	All
F5-01	0.593	173,829	All
F5-02	0.810	231,262	All
F5-03	0.944	231,400	All

[45] There are some instances where the CMI *per outage* is the same for two APFs (e.g., M1-01 and M1-02). CMI per outage is calculated as the sum of CMI divided by the sum of outages. What this indicates is that (for example) the feeders dropped from M1-01 when creating M1-02 did not experience any of the relevant forms of outage in the five years of available data.

5.0 Benefit-Cost Analysis

The Vulnerability Assessment delivers a value-agnostic relative ranking of the fragility of Hydro One's assets. The Pre-Assessment applies assumptions about customer value to estimated feeder vulnerability in order to rank individual feeders, and groups individual feeders into APFs. The Benefit Cost Analyses (BCAs) use those APFs to compare the benefits to Hydro One customers of each resilience measure against the costs of implementation.

A separate benefit-cost ratio (BCR) is calculated for each APF. This demonstrates the sensitivity of the resilience measure's cost-effectiveness to the set of feeders to which it is applied.

Guidehouse's BCAs were developed using a customized version of the OEB's generic Toolkit. The overwhelming majority of customizations applied to the Toolkit are intended to allow greater flexibility in modeling – for example to allow performing BCAs for multiple iterations of the RM within a single workbook, or to allow for the replacement of some (but not all) baseline assets by the RM asset. In those instances where the methods applied differ from those specified in the Toolkit or VASH Framework for the generic approach, Guidehouse's methods are explicitly defined in the sections below.

Section 5.0 is divided in two. The first (5.1) provides a description of the methods used for evaluating the BCAs. The second (5.2) summarizes the outcomes of the BCAs by resilience measure and APF.

5.1 Methods

Guidehouse's BCAs were developed using a customized version of the OEB's generic Toolkit. This section provides a description of the BCA methods defined in the generic Toolkit. It is intended to be sufficient to allow reviewers to reasonably interpret BCA results.

It is not, however, intended as a comprehensive articulation of the concepts and mechanics of the benefit-cost analysis under the OEB's VASH[46] and BCA[47] Frameworks. Concepts discussed in this section assume reviewers have some familiarity with benefit-cost analysis in general, and the requirements for performing it under these two OEB-published Frameworks in particular.

Section 5.1.1 briefly summarizes the key data sources informing the BCA. Section 5.1.2 provides a summary of the BCA approach, identifies the value streams included in the BCA, and discusses how they are applied. Subsequent sections provide additional detail on the most critical value streams.

Appendix D maps each of the inputs to the BCA Toolkit specified in Section 4.2.4 of the VASH Framework to its location in this report and the accompanying Excel workbooks.

5.1.1 Data Sources

Guidehouse relied on the following data sources when conducting the benefit cost analysis.

[46] Ontario Energy Board, *Vulnerability Assessment and System Hardening Report*; *EB-2024-0199 – Vulnerability Assessment and System Hardening (VASH) Project*, October 2025

Available at: https://engagewithus.oeb.ca/vulnerability-assessment-system-hardening

[47] Ontario Energy Board, *Benefit-Cost Analysis Framework for Addressing Electricity System Needs*, February 2026

Available at: https://engagewithus.oeb.ca/bcaframework

Table 19. BCA Data Sources

Item	Source
Value of Lost Load ($/CMI by Customer Class)	Interruption Cost Estimate (ICE) Calculator 2.0[48]
Resilience Measure Cost, Lifetime, and CMI Reduction Benefit Characteristics	See Section 3.0
Historical Outage Events (for calibrating expected outage frequency)	Guidehouse analysis of Hydro One OMS data
Historical Outage CMI per Outage (for quantifying impacts of frequency or criticality reduction on customer value)	
Historical Outage Duration (an input to the ICE calculator for estimating $/CMI values to apply for valuing changes in outage frequency or criticality).	
Distribution of Customers by Class (to capture differences in the value of lost load) and Annual Total Consumption by Class (used to identify average annual consumption per customer by class for use with the ICE calculator).	Hydro One Networks Inc. customer total by rate class in 2024 OEB data[49]

5.1.2 Summary of BCA Value Streams and Calculation

The BCA ratio output by the analysis is designed, consistent of the direction of the OEB's *BCA Framework,* to test the cost-effectiveness of any resilience measure from the perspective of Hydro One's customers. Each BCA ratio is calculated using the following equation:

Equation 4 | Benefit-Cost Ratio

$$BCR = \frac{VoLL + AvRepairReplace + AvOMA}{(AssetCost - EarlyRetAdj) + NonAssetCost + OMA}$$

Where:

BCR = The benefit-cost ratio. A value of 1 or more indicates that RM costs are lower than the benefits, considered on a present value basis.

$VoLL$ = The value of lost load (VoLL) benefit impact of the RM to customers.

This is estimated in each year as the VoLL per outage times the calibrated probability-weighted number of outages in the baseline scenario, *minus* VoLL per outage times the calibrated probability-weighted number of outages in the RM scenario.

[48] Lawrence Berkeley National Laboratory. Interruption Cost Estimate Calculator (version 2.2.0). ICE Calculator. Accessed February 2026.

[49] Ontario Energy Board. Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.2 Market Monitoring Information. Available at: https://www.oeb.ca/ontarios-energy-sector/open-data

This value stream is described in more detail in Section 5.1.3.

$AvRepairReplace$ = The difference between the probability-weighted annual cost to replace or repair assets failing during *force majeure* events in the baseline scenario and the probability-weighted annual cost to replace or repair assets failing during *force majeure* events in the RM scenario. This value stream is described in more detail in Section 5.1.5.

$AvOMA$ = The annual avoided OM&A costs directly attributable to the RM. This applies only in the case of the Selective Undergrounding, see Section 3.3 for more details.

$AssetCost$ = The asset capital costs associated with the RM. This value stream is described in more detail in Section 5.1.4.

$EarlyRetAdj$ = The early retirement adjustment. This applies when an RM retires existing assets before the end of their ROL, and adjusts for the baseline condition that would require – at the end of the ROL period – some other investment. This partially offsets the RM asset costs and is described in more detail in Section 5.1.4.

$NonAssetCost$ = Capital costs associated with an RM that does not directly replace the conductor or pole assets whose fragility is being modeled. These costs are incremental to Hydro One's non-RM program investments and are required to provide the RM benefits. For this VASH analysis, this is specifically the capital costs of sectionalization equipment such as switches and is applied as part of the Sectionalization and the Voltage Conversion and Sectionalization RMs. See Section 3.4 and Section 5.1.4 for more details.

OMA = Incremental OM&A expenses associated with an RM. This applies only to the Sectionalization and the Voltage Conversion and Sectionalization RMs. See Section 3.4 for more details.

All of the values included in the equation should be understood to be the present value of each of the value streams referenced above, discounted using a real social discount rate of 4%. [50]

The principal benefits included in the BCA are those associated only with *force majeure* events: reduced customer outage frequency or length attributable to *force majeure* outages, and avoided repair or replacement costs associated with *force majeure* outages. No reliability benefits (as defined in Section 1.2) are included in this analysis. Where a given RM might be expected to deliver reliability benefits, the net RM benefits will therefore (all else equal) understate the total value these RMs otherwise provide to customers.

[50] Per section 3.2.1 the BCA Framework: "*The use of a social discount rate is appropriate for use to capture the time-value of investments* [consistent with the perspective of the test] *which is to maximize the long-term net benefit of distribution service and the energy system for customers… use of a social discount rate for discount cash flows to present value is considered best practice.*"

5.1.3 Value of Lost Load (Benefit)

The direct value to customers of reduced outage frequency and duration (i.e., criticality) is one of the most critical value streams in this BCA, and the methods used for the estimation of this value stream are discussed in this section.

The value of lost load benefits of a given RM is modeled as the difference between the value of lost load in the baseline scenario and the value of lost load in the RM scenario. This difference is impacted by changes in the projected frequency of outages, the projected criticality[51] of outages (when they occur), and the projected value per customer-minute of outages.

This section is divided in three parts: the first part describes how the impact to the projected frequency of outages due to each RM is estimated, the second part describes how the impact to criticality (in terms of customer minutes of interruption – or CMI) of outages due to each RM is estimated, and the final part describes how CMI impacts are valued in this analysis based on use of the ICE calculator.

5.1.3.1 Outage Frequency and Calibration

Guidehouse's approach to modeling outage frequency matches that used in the generic Toolkit. Adjustments to the Toolkit's formulas have been applied to allow for expected outages across multiple locations (APFs) and to consider the impact on expected outages when only some (but not all) existing assets in a given sub-class are replaced as part of the RM.[52]

The Clustered Hardening, Covered Conductor, and Selective Undergrounding RMs are modeled as driving benefits by reducing outage frequency.

For both the baseline and RM scenario, the expected value of the number of outages for a given APF in each year is calculated as the expected value (or probability-weighted) number of asset failures in a given year, scaled by an APF-specific (or in the generic Toolkit, location-specific) calibration factor.

The calibration factor (the parameter "theta" in the generic Toolkit) is developed as the ratio of the observed average outages per year for the historical period (see Table 18), divided by the uncalibrated expected value outages per year in the calibration year (for this analysis, 2026). Observed historical outages are asset-specific: for Clustered Hardening only historical pole-based outages are considered, for Covered Conductor only historical conductor-based outages are considered, and for all other RMs both types of outage are considered.

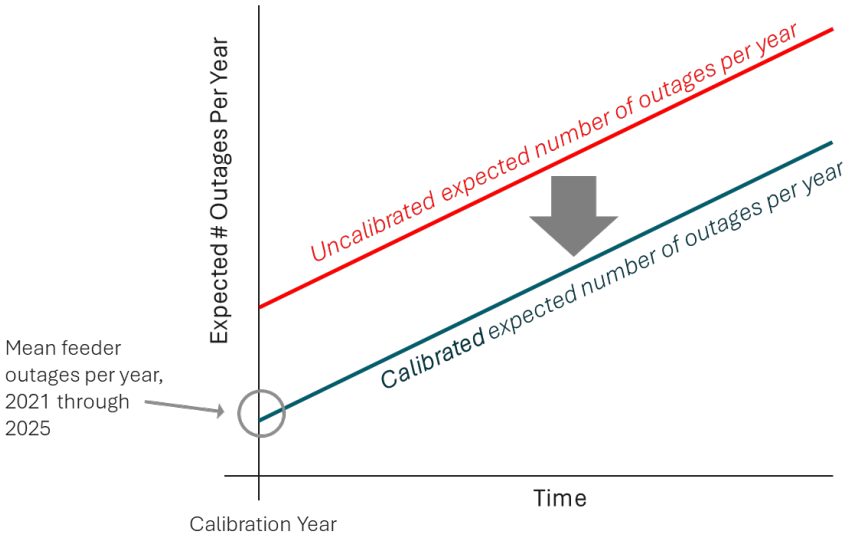
The uncalibrated expected value (probability weighted number) of outages per year is calculated as the dot product (or sum product) of the vector of uncalibrated failure probabilities by sub-class and the vector of asset counts by sub-class in the given year.

The ratio of observed outages to uncalibrated expected outages in the calibration year is termed "theta" in the Toolkit and is used to scale projected outages to align with historically observed outages. The distance between the red line and the blue line in the illustrative example in Figure 11 is equivalent to the product of the uncalibrated expected number of outages and $(1 - \theta)$.

[51] Per VASH Framework, criticality reductions are when "*the project reduces the expected outage durations and/or number of customers impacted by an outage.*"

[52] The generic Toolkit implicitly requires one-for-one replacement of all assets at a given location. This is appropriate when considering the application of RMs to specific feeder segments, but not for this VASH analysis which considers an average feeder (APF). Whole feeders (rather than segments) are considered as part of the BCA due to the available granularity of historical outage data (at the feeder level).

Figure 11. Illustrative Example of Calibration



The historically observed number of outages used to derive calibration factors in this analysis is, per Section 4.2.4 of the VASH Framework, based on 5 years of OMS data for *force majeure* events, and specific to the grid locations (the feeders included in the APF) being targeted by the project (the RM).

Calibration ensures that projected probability-weighted expected outages in the base year are tied to historical sample means (expected to be approximately equivalent to the probability weighted expected values in repeated re-sampling) and thus reflect empirical outcomes. Also, as noted in the VASH Framework, "*calibration to historic outage data accounts for the likelihood that two or more assets will fail during the same weather event.*"

For each baseline scenario the projected frequency of outages is equal to the dot product of baseline asset counts and each asset sub-class's calibrated probability of failure. In the calibration year, the baseline projected frequency of outages for all RMs modeled in this analysis will, by construction, be equal to the historic average frequency of outages.

For each RM scenario, the projected frequency of outages is equal to the dot product of replacement asset counts and each sub-class's calibrated probability of failure.

Put another way, the RM-driven change in number of outages per year is, for a given APF:

Equation 5 | Calculating the RM-Drive Change in Number of Outages Per Year

$$\Delta Outages_t = \sum_{i=1}^{I}\left[\left(Pfail_{i,t} \cdot BaseCount_{i,t}\right) - \left(Pfail_{i,t} \cdot RMCount_{i,t}\right)\right]$$

Where:

$\Delta Outages_t$ = Change in number of outages expected in year *t*

$BaseCount_{i,t}$ = The count of assets in sub-class *i* in the baseline scenario.

$RMCount_{i,t}$ = The count of assets in sub-class *i* in the resilience measure scenario.

The count of assets by sub-class will differ in the RM scenario from the baseline scenario for the assets being addressed by the RM.

For example, as part of the Clustered Hardening RM, there may be a count of 3 poor condition poles in the baseline scenario (e.g., $BaseCount_{i=\text{Wood (Poor Condition) | Class 3 or Better | Coniferous Deciduous Mix | On-Road},t=2026}$ = 3) that would become a count of zero poor condition poles in the RM scenario (e.g., $RMCount_{i=\text{Wood (Poor Condition) | Class 3 or Better | Coniferous Deciduous Mix | On-Road},t=2026}$ = 0).

$Pfail_{i,t}$ = Probability of failure of asset sub-class *i* in year *t*. This is the *calibrated* probability of failure, calculated as shown in the equation below.

The probability of failure of asset sub-class *i* in year *t* is calculated as

Equation 6 | Calibrated Probability of Failure

$$Pfail_{i,t} = \theta \cdot UncalibPfail_{i,t}$$

Where:

$UncalibPfail_{i,t}$ = Is the uncalibrated probability of failure of asset sub-class *i* in year *t*.

θ = Is the calibration factor specific the given APF and RM.

The calibration factor (theta) and is calculated as

Equation 7 | Calibration Factor (Theta)

$$\theta = \frac{ObsOutages}{UncaliOut_{t=2026}}$$

Where:

$ObsOutages$ = Is the average number of outages per year observed on average by the feeders included in the given APF over the period 2021 through 2025

$UncalibOut_{t=2026}$ = Is the expected value number of outages in the calibration year (2026 for this study) based on the uncalibrated baseline failure probabilities in that year, or: $\sum_{I}^{i=1}\left(UncalibPfail_{i,t=2026} \cdot BaseCount_{i,t=2026}\right)$

Consider a simplified example: a feeder with two asset sub-classes A and B with uncalibrated probabilities of failure of 5% and 10% in the base year ($UncalibPfail_{i=A,t=2026}$=0.05 and $UncalibPfail_{i=B,t=2026}$ = 0.1). If there are 100 of each asset sub-classes ($BaseCount_{i=A,t=2026}$=100 and $BaseCount_{i=B,t=2026}$=100 then $UncalibOut_{t=2026} = 100 \cdot 0.05 + 100 \cdot 0.1) = 15$. If, historically, there has been on average 0.5 outages per year ($ObsOutages = 0.5$) then $\theta = \frac{0.5}{15} = 0.033$.

The total value of lost load for the baseline and RM scenarios is calculated by applying the projected outage frequency to the average criticality per outage (CMI per outage), and then applying this to the dollar value per CMI (i.e., VoLL derived via the ICE Calculator) for the given baseline and RM scenario.

5.1.3.2 CMI Per Outage

For the Hydro One VASH analysis, criticality is identified using a CMI per outage metric. For the baseline scenario, this is calculated as the sum of the average CMI per year across all feeders included in the APF, divided by the sum of the outages per year across all the feeders included in the APF.

For the Clustered Hardening, Covered Conductor, and Selective Undergrounding RMs, the baseline and the RM scenario CMI per outage are identical. For Sectionalization and Voltage Conversion and Sectionalization RMs, CMI per outage in the RM scenario is assumed to be lower than in the baseline scenario, as described in Section 3.4.

The generic Toolkit characterizes criticality in terms of two variables: average outage duration and average number of customers interrupted (users are expected to input these values to the ICE calculator to return an average VoLL estimate per outage). Guidehouse determined that this approach would be inappropriate for the APF-based approach, which considers average historic outage values across multiple feeders.

The reason for this is that the product of the average event duration and average number of customers impacted will not be equal to the average CMI per feeder. The product of averages may overstate the value of outages if (for example) feeders experiencing longer outages tend to have fewer customers impacted per outage. Guidehouse has for this reason used average CMI per outage as the key criticality variable.

The total value of lost load for the baseline and RM scenarios is calculated by applying this average CMI per outage to the projected frequency of outages, and then applying this product to an estimated dollar per CMI unit value of lost load.

Guidehouse has made no adjustment to the CMI per outage to reflect forecast customer growth. All else equal, Guidehouse would expect that CMI per outage by feeder to be closely correlated with customer counts per feeder, and that as customer counts increased, so too would CMI per outage. Holding CMI per outage constant over time is therefore a conservative assumption that may result in RM benefits being understated.

5.1.3.3 Value per CMI

The generic Toolkit requires users to use average customers impacted and average outage duration as inputs to the ICE tool[53] to derive a VoLL per outage value. As noted above, Guidehouse determined that, given the use of APFs, for this VASH analysis it was more appropriate to express per-outage criticality as CMI per outage.

To value that criticality, Guidehouse used the ICE calculator to estimate an average $/CMI by customer class, and applied this, within the customized tool, to the estimated average CMI per outage.

Because the VoLL per CMI varies significantly by customer class, the average CMI per outage was distributed across four classes: Residential, Small C&I, Medium C&I, and Large C&I. F-Class feeder CMI per outage were divided across only Residential, Small C&I and Medium C&I customers. M-Class feeder CMI per outage were divided across all four classes. The count of customers used to determine the share of CMI allocated to each class are the counts of residential, General Service (GS<50, GS>50), and sub-transmission customers provided in Hydro One's RRR data filings (see Table 19).

[53] Lawrence Berkeley National Laboratory. Interruption Cost Estimate Calculator (v2.2.0). ICE Calculator. Accessed February 2026.

The $/CMI for each customer class and APF are the weighted averages of $/CMI, calculated using average outage durations[54] estimated for each of the eight Feeder Groups referenced in the VA. Other non-default inputs applied by Guidehouse to the calculator are: the states considered (New York, Michigan, Ohio, and Iowa, as per the direction provided in the OEB's generic Toolkit) and the average annual consumption per customer by class (derived from 2024 customer counts and metered kWh drawn from OEB RRR data).

The $/CMI values are the same for both baseline and RM scenarios for Clustered Hardening, Covered Conductor, and Selective Undergrounding, but differ for the baseline and RM scenarios for Sectionalization and Voltage Conversion and Sectionalization RMs, to reflect the assumed impact of the RM on average outage duration (i.e., criticality).

The average baseline $/CMI values used in the value of lost load calculation are presented in Table 20. These may, along with the corresponding RM scenario $/CMI values (different only for Sectionalization and Voltage Conversion and Sectionalization RMs), may be found in the BCA workbooks that accompany this report. As the ICE calculator outputs values in US dollars, Guidehouse has converted these to Canadian dollars (shown in the table below) using an assumed exchange rate of 1.40[55]:

Table 20. Baseline $ CAD / CMI Values by APF

APF ID	Residential[56]	Small C&I	Med C&I	Large C&I
F1-01	$0.057	$6.95	$53.4	NA
F1-02	$0.057	$6.94	$53.3	NA
F1-03	$0.057	$7.01	$53.8	NA
M1-01	$0.060	$7.63	$58.0	$291.8
M1-02	$0.060	$7.66	$58.2	$292.7
M1-03	$0.058	$7.29	$55.7	$281.7
F2-01	$0.060	$7.69	$58.4	NA
F2-02	$0.059	$7.48	$56.9	NA
F2-03	$0.061	$7.96	$60.1	NA
M2-01	$0.063	$8.42	$63.3	$314.5
M2-02	$0.063	$8.48	$63.7	$316.2
M2-03	$0.061	$7.89	$59.7	$298.8
F3-01	$0.056	$6.76	$52.1	NA
F3-02	$0.057	$6.91	$53.1	NA
F3-03	$0.057	$7.03	$53.9	NA

[54] Outage durations used as inputs to the ICE calculator are specific to the asset class being addressed by the given RM. So, for example, the Clustered Hardening $/CMI values reflect the average outage durations associated with *force majeure* pole-driven outages.

[55] Bank of Canada. Annual Exchange Rates, 1 unit of US dollar converted into Canadian dollar 2025. Annual exchange rates - Bank of Canada. Accessed February 2026.

[56] The correspondence of customer groupings in this table to the classes tracked by the OEB's RRR data are: Residential = Residential, Small C&I = GS<50, Med C&I = GS>50, Large C&I = Sub-Transmission.

APF ID	Residential[56]	Small C&I	Med C&I	Large C&I
M3-01	$0.057	$7.09	$54.3	$275.9
M3-02	$0.057	$7.01	$53.8	$273.4
M3-03	$0.058	$7.14	$54.7	$277.3
F4-01	$0.064	$8.70	$65.2	NA
F4-02	$0.063	$8.52	$64.0	NA
F4-03	$0.063	$8.49	$63.7	NA
M4-01	$0.061	$8.08	$61.1	$305.2
M4-02	$0.062	$8.12	$61.3	$306.1
M4-03	$0.062	$8.19	$61.7	$307.7
F5-01	$0.057	$7.04	$54.0	NA
F5-02	$0.056	$6.73	$51.8	NA
F5-03	$0.056	$6.71	$51.8	NA

5.1.4 Asset and Non-Asset Capital Costs

The estimated impact to customer rates of distributor capital investments is the principal cost against which the benefits of each RM are compared. Consistent with the customer perspective of the test, the requirements of the BCA Framework and the mechanics of the generic Toolkit, all capital costs are inflated by a "revenue requirement factor" prior to inclusion in the BCA calculation. The derivation of this factor is used, as provided, in the generic version of the Toolkit.

Replacement asset capital costs are defined as specified in Section 3.0 and are provided for each sub-class in the BCA workbooks that accompany this report and used to derive the results presented in this report, as well as in Appendix C. Replacement asset costs are included only for the Clustered Hardening, Covered Conductor, and Selective Undergrounding RMs. For the two Sectionalization RMs, costs are consistent with the generic Toolkit Sectionalization example, characterized as incremental non-asset costs, the derivation of which is provided in Section 3.0.

Where a program involves the early retirement of assets, an early retirement cost adjustment is applied. This is applied in the same manner as in the generic Toolkit, but is presented as a separate line-item in the BCA (rather than simply being embedded as part of the asset capital cost calculation) for greater transparency.

This adjustment is analogous to the "deferred replacement credit" used in demand side management cost-effectiveness calculations[57], and captures the fact that (in early retirement scenarios) the resilience measure cost is not incremental to a "no action" scenario, but is incremental to an equipment replacement that would otherwise have occurred at the end of the asset's remaining operating life (ROL) absent the implementation of the resilience measure in advance.

[57] See, for example, Section 4.2.4 of
Independent Electricity System Operator, *Cost Effectiveness Guide for Energy Efficiency*, May 2022
Available at: https://www.ieso.ca/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification

5.1.5 Avoided Repair and Replacement Costs

This value stream captures the benefits to customers that flow from a reduction of the need for Hydro One to repair or replace assets damaged during *force majeure* events. As documented in Section 3.0, asset replacement and repair costs may be substantially higher to Hydro One in the aftermath of storms compared to proactive upgrades.

Avoided repair and replacement costs are calculated by Guidehouse as the difference between the probability-weighted repair and replacement costs in the baseline scenario and the probability-weighted repair and replacement costs in the RM scenario. This aligns with the approach used in the generic Toolkit.

Guidehouse has made an adjustment the Toolkit calculation here, using the *calibrated* expected asset failures rather than (as in the generic Toolkit) the *uncalibrated* expected asset failures in the calculation. Using calibrated expected asset failures (which are lower than the uncalibrated expected asset failures) materially *reduces* the benefits that flow from this value stream.

Guidehouse determined that this change to the generic Toolkit was prudent and appropriate in that it ensured that only avoided repair and replacement costs attributable to *force majeure* events were included in the analysis. This aligns the value stream with the assumed higher costs incurred by Hydro One for equipment repair and replacement in the aftermath of such events, and with the frequency of the expected outages that drive the VoLL customer benefit.

5.2 BCA Results

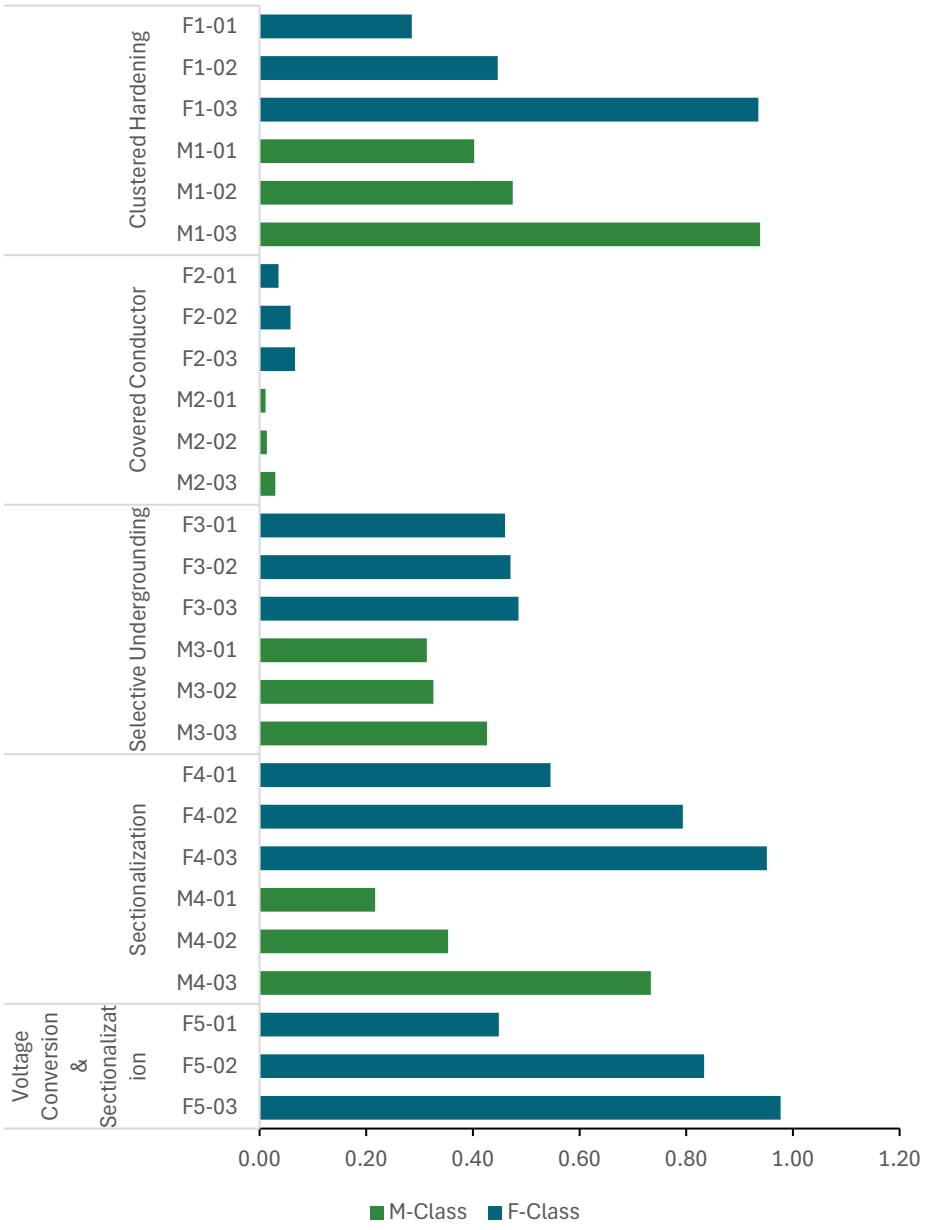
This section presents the BCA outputs for each RM. For each RM, a table of values is provided showing the present value of the key value streams for each APF. This is then followed by a short discussion of the results.

The output tables presented below for each RM may be found in each of the BCA workbooks that accompany this report. The interpretation of these results depends on the RM modeling descriptions provided in Section 3.0. The dollar values presented in these tables should be understood as being the average per feeder. These values may be scaled up by multiplying them by the number of feeders included in the APF.

Each of the subsequent sections presents the BCA results for Clustered Hardening, Covered Conductor, Sectionalization, and Voltage Conversion and Sectionalization.

An overarching visual summary of the BCA results, showing BCRs as horizontal bars, is presented in Figure 12.

Figure 12. APF Benefit-Cost Ratio Summary



The Covered Conductor APFs' BCRs are quite low, all of them falling below 0.1. This is not unexpected. Most benefits associated with covering conductor would be expected to flow from reliability, not resilience, impacts – for example: reducing outage frequency due to incidental tree contacts.

In contrast, the BCA for the Clustered Hardening RM demonstrates that the resiliency benefits nearly match the costs it imposes. The early retirement of poor condition poles and replacement by higher-class poles offers significant VoLL benefits, and helps to reduce high post-*force majeure* event equipment replacement costs.

Sectionalization, too, demonstrates significant customer value, with APF F4-03 achieving a BCR of 0.9 and M4-03 achieving a BCR of 0.8 on the basis of resilience benefits. These outcomes are sensitive to the assumption that CMI reduction benefits also flow to the feeder adjacent to the lines targeted for sectionalization (i.e., to which the candidate feeder is assumed to be tied). Guidehouse's distribution planning subject matter expert recommended that sectionalization benefits to adjacent feeders be de-rated by 50% for conservatism (e.g., to account for cases where adjacent feeders may not experience the same number of outages as the targeted feeder). If the adjacent feeder were assumed to achieve 80% (instead of 50%) of the reductions of the targeted feeder, the BCR for (for example) F4-02 would increase from 0.8 to 1.0.

The Voltage Conversion and Sectionalization RM exhibits even higher BCRs than the F-Class APFs for the Sectionalization RM. For this RM, however, the BCA includes only the incremental costs associated with sectionalization equipment – costs associated with the non-RM voltage conversion program are excluded. If non-RM costs were included, these would significantly reduce the BCR. For this RM, if there already exists a strong case to convert an F-Class feeder's voltage outside of the RM process, then, for many feeders, the incremental cost of installing the switches and reclosers necessary for sectionalization will also be cost-effective.

Understated Benefits for Covered Conductor and Selective Undergrounding

Covered Conductor and Selective Undergrounding deliver value to customers by targeting specific sub-sets of feeder assets.

The CMI reduction resilience benefits associated with the Covered Conductor and Selective Undergrounding RMs are the resilience benefits associated with replacing a 1 – 3 km segment of *average* vulnerability conductor on a feeder. This assumption will naturally result in the analysis understating the benefit of the targeted replacement of the *most vulnerable* segments of that feeder. This assumption was warranted due to the data received and the timeline for the study.

Guidehouse understands that if an undergrounding program were to be implemented segment-specific targeting would be performed as part of program implementation, to ensure that only the most cost-effective undergrounding projects are implemented.

Finally, the analysis did not demonstrate the cost-effectiveness of Selective Undergrounding for average feeder sections for any of the APFs based on the resilience benefits quantified in the model. This outcome was largely driven by limitations in the available data granularity that result in understated benefits. . For Clustered Hardening, Guidehouse was able to isolate the most vulnerable assets (poor condition poles) using condition assessment data. These poor condition poles could be modeled with failure thresholds reflecting their condition.

For this engagement, however, Guidehouse was not able to obtain data related to the highest-risk segments of overhead conductor – all overhead conductor within a given biome (as identified in its sub-class name, e.g., Farmland, Coniferous, Coniferous Deciduous Mix) on a given feeder shares the same probability of failure, making it difficult to differentiate where the benefits of undergrounding will be greatest. As a result, the quantified resilience benefits likely do not fully reflect the value that could be achieved through a targeted implementation of undergrounding (see the text box in the introduction to Section 5.2 for more details).

A detailed breakdown of the BCAs for each RM is presented in the sections that follow.

5.2.1 Clustered Hardening

Table 21 reproduces the output table from the Clustered Hardening BCA workbook and presents the present value of each value stream in 2026 dollars.

The "Total PV Costs" row is the sum of the (negative/offsetting) early retirement adjustment, capital costs and non-asset OM&A costs. Reviewers should note that capital costs presented in this table reflect (consistent with the BCA perspective of the customer) the cost to *customers* of the distributor's capital investment.[58]

Present value inputs to the BCA and the output BCR is presented for all six APFs considered.

Table 21. Clustered Hardening BCA Outputs

Metric	F1-01	F1-02	F1-03	M1-01	M1-02	M1-03
Total PV Benefits from Avoided Repairs and Replacements	$48,431	$59,383	$103,322	$18,541	$22,043	$11,292
Total PV Benefits from Frequency and Duration Reductions (VOLL)	$136,397	$210,328	$446,543	$301,858	$359,724	$727,039
Total PV Avoided OM&A Expenses	$0	$0	$0	$0	$0	$0
Total PV Early Retirement Cost Adjustment	-$212,421	-$199,040	-$194,437	-$281,883	-$285,018	-$282,825
Total PV Capital Costs	$859,899	$803,115	$782,506	$1,078,113	$1,089,397	$1,069,669
Total PV Non-Asset OM&A Costs	$0	$0	$0	$0	$0	$0
Total PV Costs	**$647,478**	**$604,075**	**$588,069**	**$796,230**	**$804,379**	**$786,844**
Total PV Benefits	**$184,827**	**$269,711**	**$549,865**	**$320,400**	**$381,767**	**$738,331**
Net PV Benefit	**-$462,651**	**-$334,364**	**-$38,204**	**-$475,830**	**-$422,613**	**-$48,513**
Benefit-Cost Ratio (BCR)	**0.29**	**0.45**	**0.94**	**0.40**	**0.47**	**0.94**
Feeder Count	2,600	850	65	622	500	125

The BCRs for the F-Class APFs (F1-01, F1-02, F1-03) improve as the APF includes a more focused group of vulnerable feeders.

APF F1-01 considers all F-Class feeders for which Guidehouse has a complete set of data. F1-03 focuses on the 65 most vulnerable. In general, as the set of feeders included in the APF is constrained to the most vulnerable feeders (determined using the ranking described in Section 4.2), the average historical frequency of outages (used to calibrate projected probability-weighted expected outages) increases and the CMI per outage increases. Historical average annual outages and CMI per outage by APF may be found in Table 18 of Section 4.5.

As described previously, the individual feeder ranking is based on: a given feeder's projected vulnerability score (inherited from the Feeder Archetype to which it belongs), the number of customers and the average number of customers it serves experiencing outages per year. This means there is not perfect correlation between calibration factor and feeder vulnerability.

In this example, M1-03's avoided repair and replacement benefits are *lower* than M1-02's despite M1-03 being drawn from a more vulnerable set of feeders. M1-03 has experienced (per Table 18) an annual average of 0.05 pole-based *force majeure* outages per year in contrast to M1-02's 0.071

[58] The capital cost to the distributor can be derived by dividing the capital costs in the BCA by Revenue Requirement Factor calculated in the generic Toolkit tab "Revenue Requirement Calculation". For the RMs under consideration in this report, this value varies between 1.42 and 1.48.

pole-based outages per year. In this case, however, though the more vulnerable APF has (in the past) been subject to fewer outages, these outages have been characterized by much higher criticality: the average CMI per outage for M1-03 feeders is approximately 4 million compared to approximately 965 thousand CMI per outage for M1-02 (see Table 18). This results in M1-03's VoLL reduction benefit being much higher than M1-02's.

5.2.2 Covered Conductor

Table 22 reproduces the output table from the Covered Conductor BCA workbook and presents the present value of each value stream in 2026 dollars.

Present value inputs to the BCA and the output BCR is presented for all six APFs considered.

Table 22. Covered Conductor BCA Outputs

Metric	F2-01	F2-02	F2-03	M2-01	M2-02	M2-03
Total PV Benefits from Avoided Repairs and Replacements	$27,110	$42,335	$48,375	$3,693	$4,511	$3,656
Total PV Benefits from Frequency and Duration Reductions (VOLL)	$24,358	$41,877	$47,377	$12,292	$15,113	$38,878
Total PV Avoided OM&A Expenses	$0	$0	$0	$0	$0	$0
Total PV Early Retirement Cost Adjustment	-$1,436,607	-$1,430,999	-$1,436,607	-$1,436,607	-$1,436,607	-$1,436,607
Total PV Capital Costs	$2,881,786	$2,881,786	$2,881,786	$2,881,786	$2,881,786	$2,881,786
Total PV Non-Asset OM&A Costs	$0	$0	$0	$0	$0	$0
Total PV Costs	**$1,445,179**	**$1,450,787**	**$1,445,179**	**$1,445,179**	**$1,445,179**	**$1,445,179**
Total PV Benefits	**$51,468**	**$84,212**	**$95,752**	**$15,985**	**$19,624**	**$42,533**
Net PV Benefit	**-$1,393,710**	**-$1,366,574**	**-$1,349,426**	**-$1,429,193**	**-$1,425,554**	**-$1,402,645**
Benefit-Cost Ratio (BCR)	**0.04**	**0.06**	**0.07**	**0.011**	**0.014**	**0.029**
Feeder Count	2,600	850	125	622	500	125

As noted previously, the BCRs for all Covered Conductor APFs are trivially small. The VoLL benefit offered by covered conductor is, from a resilience perspective, very modest. Covered conductor may significantly reduce faults under normal reliability conditions (e.g., eliminating faults due to momentary tree contacts), but appears to do little to reduce asset vulnerability under *force majeure* resilience conditions.

These BCRs are driven principally by the differences between the bare and covered conductor failure thresholds provided in Section 2.1.3.2.

5.2.3 Selective Undergrounding

Table 23 reproduces the output table from the Selective Undergrounding BCA workbook and presents the present value of each value stream in 2026 dollars.

Present value inputs to the BCA and the output BCR is presented for all six APFs considered.

Table 23. Selective Undergrounding BCA Outputs

Metric	F3-01	F3-02	F3-03	M3-01	M3-02	M3-03
Total PV Benefits from Avoided Repairs and Replacements	$184,295	$234,723	$241,313	$26,875	$23,047	$22,197
Total PV Benefits from Frequency and Duration Reductions (VOLL)	$325,662	$379,358	$413,278	$274,017	$332,447	$615,038
Total PV Avoided OM&A Expenses	$324,082	$354,465	$393,287	$381,472	$413,542	$443,925
Total PV Early Retirement Cost Adjustment	-$907,747	-$999,897	-$1,071,100	-$1,031,382	-$1,114,020	-$1,193,191
Total PV Capital Costs	$2,719,920	$3,058,614	$3,229,058	$3,207,397	$3,474,542	$3,729,467
Total PV Non-Asset OM&A Costs	$0	$0	$0	$0	$0	$0
Total PV Costs	**$1,812,174**	**$2,058,717**	**$2,157,958**	**$2,176,016**	**$2,360,521**	**$2,536,276**
Total PV Benefits	**$834,040**	**$968,545**	**$1,047,879**	**$682,364**	**$769,037**	**$1,081,160**
Net PV Benefit	**-$978,134**	**-$1,090,172**	**-$1,110,079**	**-$1,493,652**	**-$1,591,484**	**-$1,455,116**
Benefit-Cost Ratio (BCR)	**0.46**	**0.47**	**0.49**	**0.31**	**0.33**	**0.43**
Feeder Count	348	80	50	102	75	30

None of the APFs attain a BCR higher than 0.5 on the basis of resiliency benefits alone, though, like covered conductors, this RM would likely also deliver reliability benefits not quantified here. Additionally, as noted above, because the available data do not allow the analysis to target the specific feeder segments most vulnerable (and therefore most likely to benefit from undergrounding) the benefits noted above are likely understated.

5.2.4 Sectionalization

Table 24 reproduces the output table from the Sectionalization BCA workbook and presents the present value of each value stream in 2026 dollars.

Present value inputs to the BCA and the output BCR is presented for all six APFs considered.

Table 24. Sectionalization BCA Outputs

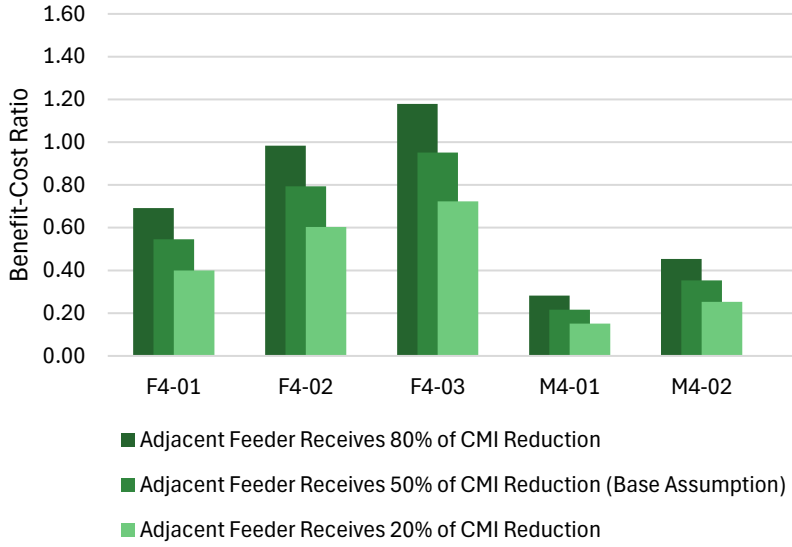
Metric	F4-01	F4-02	F4-03	M4-01	M4-02	M4-03
Total PV Benefits from Avoided Repairs and Replacements	$0	$0	$0	$0	$0	$0
Total PV Benefits from Frequency and Duration Reductions (VOLL)	$532,918	$775,303	$929,264	$365,366	$596,291	$1,237,067
Total PV Avoided OM&A Expenses	$0	$0	$0	$0	$0	$0
Total PV Early Retirement Cost Adjustment	$0	$0	$0	$0	$0	$0
Total PV Capital Costs	$874,069	$874,069	$874,069	$1,531,924	$1,531,924	$1,531,924
Total PV Non-Asset OM&A Costs	$102,922	$102,922	$102,922	$154,384	$154,384	$154,384
Total PV Costs	**$976,992**	**$976,992**	**$976,992**	**$1,686,307**	**$1,686,307**	**$1,686,307**
Total PV Benefits	**$532,918**	**$775,303**	**$929,264**	**$365,366**	**$596,291**	**$1,237,067**
Net PV Benefit	**-$444,074**	**-$201,689**	**-$47,728**	**-$1,320,942**	**-$1,090,016**	**-$449,240**
Benefit-Cost Ratio (BCR)	**0.55**	**0.79**	**0.95**	**0.22**	**0.35**	**0.73**

Feeder Count	79	50	30	173	100	30

As with the other BCAs, reliability benefits provided by this RM are not included in the BCRs presented above.

In developing this BCA, the Guidehouse team has assumed that the adjacent feeder to which the targeted feeder is attached benefits from only half of the percentage CMI reduction achieved by the targeted feeder. This assumption was chosen to be deliberately conservative, balancing the need to quantify the real benefits that flow to the adjacent feeder that is temporarily tied to the targeted feeder with uncertainty regarding proxy values assigned to the criticality and frequency of outages on the adjacent feeder. Given these uncertainties, Guidehouse has quantified the sensitivity of the BCR to this assumption and provides this plotted in Figure 13.

Figure 13. Sensitivity of Sectionalization to Adjacent Feeder Benefits De-Rating Factor



As observed from Figure 13, the degree to which sectionalization benefits an adjacent feeder is an important determination of whether the resilience benefits (alone) are sufficient to justify sectionalization. It does, however, seem evident from these results that even if the value to adjacent feeders is relatively low, sectionalization schemes for the more vulnerable of the candidate feeders have the potential to drive significant value to customers. This is especially true if reliability benefits (outside the scope of this analysis) were considered here.

Finally, it should be noted that the benefits quantified for this RM are based on projected outages calibrated to historical observed *force majeure* outages with cause codes consistent with climate-driven outages. Sectionalization may also provide benefits to customers by reducing outages classified as (for example) “human element” or “foreign interference”. These benefits are not captured here.

5.2.5 Voltage Conversion & Sectionalization

Table 25 reproduces the output table from the Voltage Conversion & Sectionalization BCA workbook and presents the present value of each value stream in 2026 dollars.

Present value inputs to the BCA and the output BCR is presented for three APFs. No M-Class feeder candidates were considered for this resilience measure, and so a BCA was performed only for three F-Class APFs.

This RM differs from the other four in that it is incremental to another investment; voltage conversion. This RM considers the costs and benefits of sectionalization when applied to an F-Class feeder that has undergone voltage conversion, but does not include any of the costs or benefits of the voltage conversion itself.

Table 25. Voltage Conversion & Sectionalization BCA Outputs

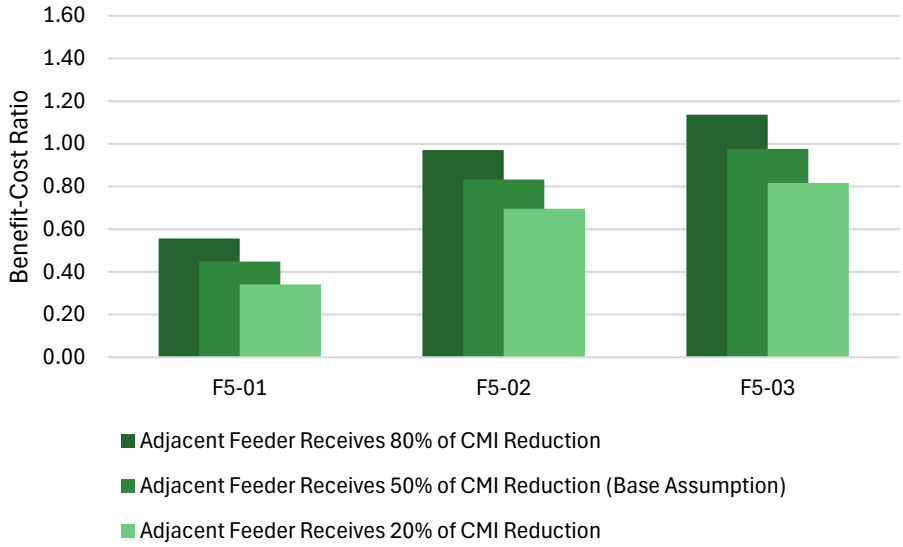
Metric	F5-01	F5-02	F5-03
Total PV Benefits from Avoided Repairs and Replacements	$0	$0	$0
Total PV Benefits from Frequency and Duration Reductions (VOLL)	$438,333	$814,193	$954,366
Total PV Avoided OM&A Expenses	$0	$0	$0
Total PV Early Retirement Cost Adjustment	$0	$0	$0
Total PV Capital Costs	$874,069	$874,069	$874,069
Total PV Non-Asset OM&A Costs	$102,922	$102,922	$102,922
Total PV Costs	**$976,992**	**$976,992**	**$976,992**
Total PV Benefits	**$438,333**	**$814,193**	**$954,366**
Net PV Benefit	**-$538,659**	**-$162,799**	**-$22,626**
Benefit-Cost Ratio (BCR)	**0.45**	**0.83**	**0.98**
Feeder Count	79	50	30

As with the other BCAs, reliability benefits provided by this RM are not included in the BCRs presented above.

In developing this BCA, the Guidehouse team has used the same adjacent feeder assumptions as for the Sectionalization RM.

Guidehouse has assumed that the adjacent feeder to which the targeted feeder is attached benefits from only half of the overall share of CMI reduction achieved by the targeted feeder. Like the Sectionalization RM Guidehouse has quantified the sensitivity of the BCR to the proxy rate at which the adjacent feeder is assumed to receive the sectionalization benefits as well as the target feeder and provides this plotted in Figure 14.

Figure 14. Sensitivity of Voltage Conversion & Sectionalization to Adjacent Feeder Benefits De-Rating Factor



6.0 Conclusions

The VA has identified that from a forward-looking climate perspective, Hydro One's most vulnerable assets are located in its East region and, to a lesser extent, in the areas of the North and Central region nearest to the East region.

The subsequently-estimated set of BCAs have demonstrated that the implementation of resilience measures to mitigate against these vulnerabilities can deliver value to customers, even when consideration of benefits is limited mostly to resilience benefits. This value has been demonstrated to increase as the focus of the resilience measure is more tightly targeted to Hydro One's most vulnerable assets.

For some BCAs no additional distribution service benefits beyond those modeled are required to ensure that the investments deliver a net benefit to consumers. For other BCAs, achieving cost-effectiveness would require the application of additional value streams to the analysis (e.g., reliability benefits) that are beyond the scope of this study, or a more targeted application of the investment to the most vulnerable portions of the system than could be modeled as part of this study.

The fact that some BCRs nearly reach 1.0 based principally on resilience benefits is a noteworthy outcome given the conservative modeling assumptions and inputs adopted by Guidehouse when addressing key uncertainties. In addition to accounting only for some of the customer benefits (with normal reliability notably excluded), the analysis does not assume any growth in customer numbers over time and uses a unit value of lost load derived from the ICE calculator, which may understate the value of lost load in *force majeure* events.

Guidehouse understands that the VASH analysis is only one input to Hydro One's planning and that Hydro One will continue to further analyze asset condition, system needs, and the full range of benefits that these RMs offer to refine the selection of projects for execution to those that provide the most value to customers.

Ways in which a targeted approach to asset and customer data collection as part of its resilience investment program will help Hydro One to identify projects most likely to deliver significant net customer benefits include:

- **Customer Data Collection.** Targeted collection of customer information associated with promising feeders or feeder segments could include:
  - *Feeder/Customer-Specific VoLL*. More precisely quantifying the value of lost load for specific customer segments or even individual customers will allow for a more accurate targeting of resilience measures to where they will deliver the most benefit. For example, quantifying the VoLL for critical loads, such as hospitals or water treatment facilities and for vulnerable customers (such as those in remote communities or in large multi-family buildings) may help to better target cost-effective resilience investments.
  - *Customer Growth*. Appropriately considering population growth projections, cross-referenced with regional planning assumptions for specific feeders (or feeder segments) of interest will help to more accurately quantify future resilience benefits in locations expected to experience significant load growth in the future.
- **Asset Engineering Data Collection and Analysis.** A focused assessment of specific assets on feeders or feeder segments by engineers and planners could more precisely identify:
  - *Addressable Vulnerabilities*. Considering vegetation or the surrounding conditions of a specific feeder segment as well as its location relative to the station and customers could

allow engineers to more precisely identify assets most suitable for undergrounding. Such work would also allow planners to better quantify the value of this RM.

- *Cost Efficiencies and Network Effects*. Evaluating costs on a more specific location-by-location basis can help identify opportunities to bundle or sequence infrastructure improvements efficiently across projects and bring down costs.

- **Comprehensive Assessment of Benefits.** A focus on a single primary value stream (resilience) is appropriate for a higher-level analysis like the VASH study, but site-specific assessments conducted as part of Hydro One's standard program implementation process should consider benefits comprehensively. Including consideration of reliability and other quantitative and qualitative benefits to customers will help to identify those opportunities for resilience measures that most drive value to Hydro One customers.

Appendix A. Asset Classes and Sub-Classes

Guidehouse performed the vulnerability assessment and benefit cost analysis on two asset classes: poles and conductor.

Poles were classified into 39 sub-classes, with the primary fragility characteristics of material of construction, pole condition, approximate pole class, and vegetation type present.

Additional flags for "On" or "Off-Road" were included to account for differences in planned asset replacement costs by pole location. Conductor was classified into nine asset sub-classes, providing differentiation by type and forestry region. A complete table of asset sub-classes is provided in Table 26.

Table 26. Asset Sub-Classes

Asset Class	Asset Sub-Class
Pole	Wood (Poor Condition) | Class 3 or Better | Farmland | On-Road
Pole	Wood (Good/Fair Condition) | Class 3 or Better | Farmland | On-Road
Pole	Wood (Poor Condition) | Class 3 or Better | Coniferous Deciduous Mix | On-Road
Pole	Wood (Good/Fair Condition) | Class 3 or Better | Coniferous Deciduous Mix | On-Road
Pole	Wood (Poor Condition) | Class 3 or Better | Coniferous | On-Road
Pole	Wood (Good/Fair Condition) | Class 3 or Better | Coniferous | On-Road
Pole	Wood (Poor Condition) | Class 4 or Worse | Farmland | On-Road
Pole	Wood (Good/Fair Condition) | Class 4 or Worse | Farmland | On-Road
Pole	Wood (Poor Condition) | Class 4 or Worse | Coniferous Deciduous Mix | On-Road
Pole	Wood (Good/Fair Condition) | Class 4 or Worse | Coniferous Deciduous Mix | On-Road
Pole	Wood (Poor Condition) | Class 4 or Worse | Coniferous | On-Road
Pole	Wood (Good/Fair Condition) | Class 4 or Worse | Coniferous | On-Road
Pole	Wood (Poor Condition) | Class 3 or Better | Farmland | Off-Road
Pole	Wood (Good/Fair Condition) | Class 3 or Better | Farmland | Off-Road
Pole	Wood (Poor Condition) | Class 3 or Better | Coniferous Deciduous Mix | Off-Road
Pole	Wood (Good/Fair Condition) | Class 3 or Better | Coniferous Deciduous Mix | Off-Road
Pole	Wood (Poor Condition) | Class 3 or Better | Coniferous | Off-Road
Pole	Wood (Good/Fair Condition) | Class 3 or Better | Coniferous | Off-Road
Pole	Wood (Poor Condition) | Class 4 or Worse | Farmland | Off-Road
Pole	Wood (Good/Fair Condition) | Class 4 or Worse | Farmland | Off-Road

Asset Class	Asset Sub-Class
Pole	Wood (Poor Condition) | Class 4 or Worse | Coniferous Deciduous Mix | Off-Road
Pole	Wood (Good/Fair Condition) | Class 4 or Worse | Coniferous Deciduous Mix | Off-Road
Pole	Wood (Poor Condition) | Class 4 or Worse | Coniferous | Off-Road
Pole	Wood (Good/Fair Condition) | Class 4 or Worse | Coniferous | Off-Road
Pole	Removed Pole | Coniferous
Pole	Removed Pole | Coniferous Deciduous Mix
Pole	Removed Pole | Farmland
Conductor	Bare | Farmland
Conductor	Bare | Coniferous Deciduous Mix
Conductor	Bare | Coniferous
Conductor	Covered | Farmland
Conductor	Covered | Coniferous Deciduous Mix
Conductor	Covered | Coniferous
Conductor	Underground | Farmland
Conductor	Underground | Coniferous Deciduous Mix
Conductor	Underground | Coniferous

Appendix B. Asset Failure Thresholds

This section provides additional detail on the fragility thresholds applied to Hydro One assets and the methodology used to develop them.

B.1 Wind Thresholds

For wind hazards, Guidehouse prioritized sources that explicitly model the distribution assets of interest and are widely cited in academic and industry literature. Wind thresholds were developed to represent the onset of meaningful structural failure, rather than easily repairable damage.

B.1.1 Poles / Wind

Guidehouse selected Darestani and Shafieezadeh as the primary source for wind fragility because it provides a consistent, internally comparable set of fragility curves across multiple pole classes using a single modelling framework.[59,60] Many alternative studies model only a single pole class, which can introduce inconsistencies when combining results across sources. In addition, the authors of these papers explicitly address age-based degradation, allowing pole age degradation models to be used as a proxy for condition-based degradation, e.g., a pole in "Poor" condition behaves like a pole of a certain age, while a pole in "Good/Fair" condition behaves like a younger pole. Notably, both studies used here by Guidehouse are widely cited in utility fragility literature, supporting their use as a credible industry reference.

Darestani and Shafieezadeh express wood pole fragility as a function of 3-second gust wind speed, while Environment and Climate Change Canada (ECCC) projections in the OEB's Toolkit are provided as 10-minute sustained wind speeds. Guidehouse applied a standard gust conversion factor based on the Durst curve to convert gust speeds to 10-minute sustained wind speeds for equivalent unit comparison.[61] For a 10-minute to 3-second conversion, this corresponds to an approximate gust factor of 1.48, e.g., a 100 km/h 10-minute sustained wind speed is estimated to result in 3-second gusts of ~148 km/h. To convert Darestani and Shafieezadeh's wind speeds to align with ECCC projections, they were divided by 1.48.

Guidehouse assumed Class 3 or better poles behaved with Class 3 pole fragility, while Class 4 or worse poles behaved with Class 5 pole fragility. The class 5 pole assumption was made to avoid overvaluing strength of weak and legacy poles on the Hydro One system. Failure thresholds were defined at the 40 percent probability of failure point on the underlying fragility curves. This level represents a balance between capturing meaningful structural vulnerability and avoiding thresholds that correspond only to extreme, near-certain failure conditions.

Guidehouse represented pole condition using age-based degradation relationships from Shafieezadeh et al. An exponential degradation model was applied to reflect loss of structural capacity over time; "Good/Fair" condition poles were assumed to be equivalent to a 25-year-old pole, while "Poor" condition poles were assumed equivalent to a 90-year-old pole. These age-based assumptions lead to an effective strength of approximately 99% and 62% of new pole strength, respectively. Guidehouse selected a 90-year effective age for poor condition poles to

59 Y. Mohammadi Darestani and A. Shafieezadeh, "Multi-Dimensional Wind Fragility Functions for Wood Utility Poles," Engineering Structures 183 (2019): 937–948. https://doi.org/10.1016/j.engstruct.2019.01.048

60 A. Shafieezadeh, U. P. Onyewuchi, M. M. Begovic, and R. DesRoches, "Age-Dependent Fragility Models of Utility Wood Poles in Power Distribution Networks Against Extreme Wind Hazards," IEEE Transactions on Power Delivery 29, no. 1 (February 2014): 131–139, https://doi.org/10.1109/TPWRD.2013.2281265

61 Krayer, W. R., & Marshall, R. D. (1992). *Gust factors applied to hurricane winds*. **Bulletin of the American Meteorological Society, 73**(5), 613–618. https://doi.org/10.1175/1520-0477(1992)073<0613:GFATHW>2.0.CO;2

account for the substantial number of poles above 60 years old on the Hydro One system which may additionally be in poor condition for their age. Table 27 provides base pole wind thresholds by pole sub-class.

Table 27. General Sub-Class Pole Wind Thresholds

Sub-Class	10-Minute Wind Speed (km/h)	Equivalent 3 Second Gust (km/h)
Class 3 or Better | Good	167.1	247.3
Class 3 or Better | Poor	104.9	155.3
Class 4 or Worse | Good	140.2	207.5
Class 4 or Worse | Poor	88.0	130.2

To address Hydro One's experience with vegetation fall-in pulling down distribution poles, Guidehouse applied a cap on pole wind thresholds based on surrounding vegetation to reflect the fact that the dominant failure mode[62] for strong, good condition poles is damage due to vegetation fall-in rather than direct pole downing from wind loading alone.

Hydro One territory has both hardwood and softwood trees. In general, deciduous trees are classified as hardwoods, while coniferous trees are classified as softwoods, with softwoods tending to experience structural damage at lower wind speeds than hardwood trees.[63] Accordingly, Guidehouse applied softwood-influenced wind thresholds in coniferous regions and hardwood-influenced thresholds in deciduous regions.

Table 28 summarizes the expected degree of tree damage for hardwood and softwood species across wind speed ranges and provides the basis for threshold selection.

Table 28. Expected Degree of Wind Induced Tree Damage in 10-Minute Sustained Wind Speeds (km/h)

Damage	Lower Bound Hardwood	Expected Hardwood	Upper Bound Hardwood	Lower Bound Softwood	Expected Softwood	Upper Bound Hardwood
Small Limbs Break	52.1	65.1	78.1	52.1	65.1	78.1
Large Branches Break	66.2	80.3	95.5	67.3	81.4	95.5
Trees Uprooted	82.4	98.7	128.0	79.2	94.4	122.6
Trunks Snapped	100.9	119.3	145.4	95.5	112.8	138.9

[62] There is, naturally, an underlying distribution of different ways in which a pole-driven outage may be caused by wind. Modeling climate resilience requires making simplifying assumptions about these underlying causes. This underlines the importance of mechanisms within the modeling (e.g., calibration to historical outages) to ensure that imprecisions necessitated by modeling assumptions do not materially impact the conclusions drawn from it.

[63] *Frelich, L. E., and E. J. Ostuno, 2012: Estimating wind speeds of convective storms from tree damage. Electronic J. Severe Storms Meteor., 7 (9), 1–19.*

Source: Frelich, L. E., and E. J. Ostuno, 2012: Estimating wind speeds of convective storms from tree damage. Electronic J. Severe Storms Meteor., 7 (9), 1–19.

Guidehouse applied the upper bound wind speed at which trees are uprooted as a maximum threshold for pole wind failures. For the Farmland region Guidehouse did not modify failure thresholds. Table 6 in the main body of the report, above, shows the final assigned pole wind thresholds.

B.1.2 Conductor Wind

Industry literature indicates that conductors exhibit very high wind tolerance and direct conductor failure from wind alone in Hydro One territory is unlikely.[64] In practice, wind-related conductor outages most often result from secondary mechanisms such as vegetation fall-in or conductor clashing. As a result, Guidehouse developed conductor wind thresholds based on wind speeds associated with tree damage, rather than conductor structural limits alone to reflect conductor failure in Hydro One territory from vegetation fall-in.

Farmland areas were assumed to have limited tree coverage and therefore reduced exposure to vegetation fall-in. As a result, higher wind thresholds were applied to farmland conductors, with failure assumed to occur primarily through conductor slapping or mechanical failure at extreme wind speeds rather than vegetation contact.

Covered conductors were assumed to have greater resistance to vegetation contact relative to bare wire, particularly for branch contact. This advantage was reflected in higher wind failure thresholds for covered conductors. Underground conductors were assumed not to experience wind-related failures.

For bare wire conductors, wind failure thresholds were defined as the average between the expected wind speeds associated with large branch breakage and trees uprooting as shown in Table 28, reflecting the likelihood of damaging vegetation contact without requiring complete tree failure. In farmland areas, bare wire failure was assumed to be driven by conductor slapping at extreme wind speeds, and thresholds were conservatively set at expected wind speeds associated with softwood trunk snapping.

For covered conductors, wind failure thresholds were defined as the expected wind speed associated with tree uprooting, reflecting the assumption that branches may strike the conductor without causing failure. In farmland areas, covered conductor failure was similarly assumed to occur at wind speeds associated with trunk snapping but was elevated to the hardwood threshold to reflect covered conductor's resistance to phase-to-phase contact faults. The final thresholds applied are given in Table 7.

[64] Ma, L., P. Bocchini, and V. Christou. 2020. "Fragility models of electrical conductors in power transmission networks subjected to hurricanes". Structural Safety. Vol. 82. pp. 101890.

B.2 Ice Thresholds

Compared to extreme wind, substantially less industry and academic literature is available that directly quantifies utility asset fragility as a function of freezing rain ice accretion. In many studies, ice accretion is considered as a modifier to wind resistance, with authors examining how ice loading reduces an asset's ability to withstand wind, rather than as an independent loading mechanism.[65,66] This reflects the well-established understanding that concurrent ice accretion and wind loading is significantly more damaging than either hazard acting in isolation, which is also captured by wind loading influenced thresholds in CSA conductor ice loading standards.[67]

In the absence of quantitative, asset-specific ice accretion fragility curves, Guidehouse relied on alternative industry-recognized sources to establish defensible ice failure thresholds. The primary industry references used was the Sperry-Piltz Ice Accumulation (SPIA) Index. This was developed specifically to assess potential utility system damage resulting from freezing rain events and has been endorsed by the National Association of Regulatory Utility Commissioners (NARUC) for planning purposes. [68]

The SPIA Index, shown in Table 8 (included in Section 2.1.3 of the main report), provides qualitative descriptions of expected utility damage and service impacts across increasing levels of ice accretion.

To align with the low wind assumption resulting from climate data limitations as described in Section 2.1.3, Guidehouse focused on SPIA damage descriptions corresponding to freezing rain events with wind speeds below approximately 25 km/h. These qualitative damage states were then used, in combination a review of asset failures observed in recent ice storms (see Section B.3.2), to develop asset-specific failure thresholds representing the onset of significant structural damage, consistent with high impact climate *force majeure* events.

B.2.1 Pole Ice Accretion

Guidehouse assigned pole ice accretion fragility thresholds informed by the SPIA index and observed outcomes of historic ice storms. For wood poles, Guidehouse applied the same age-based degradation assumptions used for wind fragility modelling.

For new wood poles, baseline ice accretion failure thresholds of 45 mm and 40 mm of ice accretion were applied to Class 3 or Better and Class 4 or Worse poles, respectively. These thresholds are consistent with SPIA damage index 5: "*Catastrophic damage to entire exposed utility systems including both distribution and transmission networks*". SPIA index 5 applies to ice accretions of more than approximately 38mm.

As noted in Section B.3.2, below, the most significant ice accretion in recent history was observed during the March 2025 ice storm, with as much as 25 mm of ice accretion reported. Previous to

[65] Ma, Y., Q. Dai, and W. Pang. 2020. *Reliability assessment of electrical grids subjected to wind hazards and ice accretion with concurrent wind*. Journal of Structural Engineering. American Society of Civil Engineers (ASCE). Vol. 146, no. 7. pp. 4020134.

[66] Rezaei, S.N., L. Chouinard, F. Legeron, and S. Langlois. 2015. *Vulnerability analysis of transmission towers subjected to unbalanced ice loads*. 12th International Conference on Applications of Statistics and Probability in Civil Engineering, ICASP12. pp. 1-8. https://open.library.ubc.ca/soa/cIRcle/collections/53032/items/1.0076203

[67] For example CSA 22.3 # 2025 which specifies a severe loading condition of 19 mm of radial ice thickness with horizontal wind loading of 400 N/m^2 (approximately 90 km/h).

[68] http://pubs.naruc.org/pub/53A0CCE6-2354-D714-51B2-A032B9278E53

that, the 1998 ice storm – which resulted in more than 7,000[69] pole failures – was observed to result in ice accretions in the range of 40 – 80 mm across most of the area affected.

Guidehouse assumed wood poles exhibited identical strength loss with respect to ice as with wind, with Good/Fair poles exhibiting 99% of original pole strength (so, for example, shifting from a failure threshold of 45mm for brand new Class 3 or Better poles to 44.7 mm) and Poor condition poles exhibiting 62% of new pole strength. This approach led to the thresholds in Table 29.

Table 29. Pole Ice Accretion Thresholds

Sub-Class	Ice Accretion Threshold (mm)
Class 3 or Better | Good	44.7
Class 3 or Better | Poor	28.1
Class 4 or Worse | Good	39.8
Class 4 or Worse | Poor	25.0

Notably, degraded wood poles fall into lower SPIA damage categories due to their reduced structural capacity. Under the applied degradation assumptions, Poor condition poles correspond to SPIA Index 3 and 4 damage states, where "*numerous utility interruptions and damage to main feeder lines are expected*." These thresholds reflect the increased vulnerability of degraded poles to ice loading and are consistent with the qualitative damage descriptions provided by the SPIA Index.

As with poles and wind, Guidehouse applied a capped ice threshold based on vegetation region. In Freilich et al., softwood demonstrates approximately 95% strength compared to hardwood. Guidehouse assumed the same strength characteristics hold true for resistance to ice accretion and applied a conservative ice threshold of 31.8 mm (center of SPIA index 4) as the amount at which hardwood trees are uprooted; applying the 95% strength factor led to a 30.2 mm ice threshold for softwood trees. Table 9 provides the ice accretion thresholds capped to account for potential tree fall in.

B.2.2 Conductor Ice Accretion

Guidehouse applied a qualitative approach to develop conductor ice accretion fragility thresholds based on the SPIA ice index, with additional adjustments to reflect differences in vegetation exposure across forestry regions.

Consistent with the wind methodology, lower ice accretion thresholds were applied in coniferous regions to reflect the presence of softwood tree species while higher thresholds were applied in deciduous regions to reflect the comparatively greater resistance of hardwood species.

Thresholds for covered conductors were assigned at the same level as bare wire to account for additional ice loading due to greater conductor diameter of covered conductor (i.e., while stronger than bare conductor, covered conductor may accrete more ice than bare conductor, offsetting the strength improvement). As with wind hazards, underground conductors were assumed not to experience failures due to ice accretion.

Guidehouse's assigned ice accretion failure thresholds for conductor are shown in Table 10. The assigned thresholds fall within SPIA Index 3, which corresponds to "*numerous utility interruptions with some damage to main feeder lines and equipment expected*."

[69] Ontario Hydro, *More than Energy – Final Annual Report January 1998 – March 1999,* September 1999 https://www.oefc.on.ca/pdf/ENGFINAL.pdf

B.3 Evaluation of Failure Thresholds Against Recent Climate *Force Majeure* Events

To evaluate the accuracy of the failure thresholds, Guidehouse investigated the agreement between the assigned thresholds and Hydro One damage in recent wind and freezing rain *force majeure* events. Guidehouse collected and analyzed historical weather data from Environment and Climate Change Canada's (ECCC's) Meteorological Service of Canada Open Data Server and reviewed contemporary forecasts and reports for the May 2022 Derecho wind storm and the April 2023, December 2024, March 2025, and December 2025 ice storms.[70] Following investigation of these events, Guidehouse believes the assigned thresholds align with the recorded damage.

B.3.1 Wind *Force Majeure* Events

Guidehouse collected daily data summaries from ECCC for all weather stations in Ontario with data available on May 21, 2022. Daily summaries provide peak wind gusts, which Guidehouse found hit a maximum of 131 km/h, equivalent to 88.5 km/h 10-minute sustained winds using the same gust conversion factor as described in Section 2.1.3. Review of post-event reports indicate potentially higher gusts of up to 141 km/h in certain locations, equivalent to 95.2 km/h 10-minute sustained speeds.[71,72] Hydro One's overhead distribution system sustained substantial damage from this event, including ~2,000 broken poles, indicating that pole failure thresholds for a subset of Hydro One's poles should fall below 88.5 km/h in 10-minute sustained wind speeds.[73] Notably, the assigned failure threshold of 88.0 km/h for poor condition Class 4 or worse wood poles suggest that Hydro One's weaker and poor condition poles would be expected to fail in the locations that saw the highest wind speeds during the May 2022 Derecho, indicating alignment of estimated thresholds with observed recent historical wind driven climate *force majeure* events.

B.3.2 Freezing Rain *Force Majeure* Events

Guidehouse reviewed recent historical freezing rain ice accretion *force majeure* events using a similar approach to that in the previous section. However, daily weather summaries from ECCC do not provide ice accretion, instead giving snow accumulation, rain accumulation, or total precipitation amount. Therefore, Guidehouse relied on contemporary news reports, forecasts, and after-action reports to gain an understanding of the range of ice accretion in these events. Daily historical weather data summaries were used to determine the peak concurrent wind speeds during these ice accretion events to assess comparability to the low wind assumption made in Section 2.1.3.

Guidehouse found that the April 2023 Ice Storm had average peak gusts of ~57 km/h, corresponding to sustained winds of ~37 km/h, making it difficult to draw reliable comparisons given the low wind assumption. The December 2024, March 2025, and December 2025 events had lower wind speeds, with average peak gusts of ~43 km/h, ~43 km/h, and ~45 km/h, respectively, corresponding to approximate 10-minute wind speeds of 28 to 30 km/h, slightly above the low wind assumption but near enough to evaluate threshold accuracy.

The March 2025 ice accretion event had the most significant ice accretion, with CatIQ, a Toronto based organization that provides insurance industry catastrophe data, reporting up to 25 mm of ice

[70] https://dd.weather.gc.ca/today/

[71] Some updates on the 2022 ON-QC derecho - Some updates on the 2022 ON-QC derecho - Western University

[72] Ashton_GLOMW-Derecho_Publish.pdf

[73] Hydro One restores power to more than 652,000 customers following Saturday's devastating storm - May 26, 2022

accretion.[74] Contemporary forecasts for the December 2024 and 2025 events from The Weather Network indicated expected freezing ice accretion in the range of 5 to 20 mm depending on location.[75,76] The most impactful of these events was the March 2025 storm, after which Hydro One replaced ~2,000 poles. Guidehouse's assigned ice threshold of 25.0 mm for poor condition class 4 and weaker poles sits at the highest end of observed ice accretion amounts, however, these events came with higher concurrent wind speeds than the conservative wind assumption made by Guidehouse because of climate data limitations. Therefore, it would be expected that some of the weakest and worst condition poles on the Hydro One system would fail slightly below Guidehouse's assigned threshold during events with wind speeds slightly higher than Guidehouse assumed 25 km/h cap. Guidehouse believes the observed asset behavior in these events indicates alignment with the assigned asset thresholds.

The impact of the 1998 St. Lawrence Valley ice storm may also be informative. According to a contemporary report by Statisitics Canada, ice thickness in south-eastern Ontario was, in the worst-affected areas, observed to fall in the range of as much as 80 – 100 mm,[77] though in most of the areas of Ontario affected ice thickness fell in the 40 – 80 mm range. Statistics Canada reported that "*more than 30,000 wooden poles were brought down*", and Ontario Hydro's final annual report for that year[78] identified that "*seven thousand wooden distribution poles snapped like matchsticks...*"

B.4 Exceedance Probabilities

This section describes how the climate exceedance probabilities – the probability in any given year that the severity of each climate peril will exceed the failure threshold of a given asset sub-class – are developed.

Following assignment of asset failure thresholds, Guidehouse used ECCC projected climate data to derive the projected probability of exceeding the assigned thresholds for each climate location, in each year and for each climate scenario. These are the exceedance probabilities that are used to quantify the probability an asset in a given sub-class failing in any given year.

Projected ECCC climate data for wind and freezing rain ice accretion is provided in the OEB's Toolkit in the form of return intervals. Return intervals define discrete points along a climate peril probability curve and thus provide the probability of occurrence associated with peril intensity, e.g., a 1:100-year return interval corresponds to 1% annual probability of occurrence. ECCC data includes the 1:10-, 1:20-, 1:50-, 1:100-, and 1:200-year return intervals corresponding to 10% to 0.5% annual probability of occurrence.

To construct a continuous view of hazard probability, Guidehouse interpolates the points along the climate hazard curve to allow for sampling at the relevant asset hazard thresholds. This

[74] CatIQ. (2025, April 30). *CAD 342M – CatIQ discloses initial industry loss estimate for the Ontario and Quebec ice storm of March 2025*. https://public.catiq.com/2025/04/30/cad-342m-catiq-discloses-initial-industry-loss-estimate-for-the-ontario-and-quebec-ice-storm-of-march-2025/

[75] The Weather Network. (2024, December 9). *Icy Monday in store for some as Ontario slips into a quick change*. https://www.theweathernetwork.com/en/news/weather/forecasts/icy-monday-in-store-for-some-as-ontario-slips-into-a-quick-change

[76] The Weather Network. (2025, December 28). *High-impact winter storm bears down on Ontario, outages possible*. https://www.theweathernetwork.com/en/news/weather/forecasts/high-impact-winter-storm-bears-down-on-ontario-outages-possible

[77] Statistics Canada, *Ice Storm '98*, Catalogue No. 11-008, Winter 1998 Canada Social Trends https://www150.statcan.gc.ca/n1/en/pub/11-008-x/1998003/article/4006-eng.pdf?st=etPuZibC

[78] Ontario Hydro, *More than Energy – Final Annual Report January 1998 – March 1999*, September 1999 https://www.oefc.on.ca/pdf/ENGFINAL.pdf

interpolation is performed for each location, year, and climate scenario using a log-linear interpolation to align with the log-linear shape of the tail of a climate hazard distribution.[79] The probability of exceeding a specified intensity threshold H is then given by

Equation 8 | Probability of Exceedance

$$P_{exceedance} = 10^{-\left(log_{10}(R_L)+\frac{H-I_L}{I_U-I_L}(log_{10}(R_U)-log_{10}(R_L))\right)},$$

where R_L is the return period lower bound, R_U is the return period upper bound, I_L is the peril intensity at R_L, and I_U is the hazard intensity at R_U.

For hazard thresholds above the 1:200 return-interval intensity, Guidehouse sets the exceedance probability to zero. Interpolation is applied only within the range of ECCC-provided data. Estimating probabilities beyond the highest return interval would require tail extrapolation, which is highly model-dependent and can produce unstable results. Limiting probabilities to the observed ECCC data range and assigning zero exceedance outside that range is therefore a conservative, data-grounded assumption.

For hazard thresholds below the lowest return-interval point provided in the ECCC data (1:10 year-return interval), probabilities are estimated using a lower-tail interpolation rule. This method anchors the curve at a synthetic point of zero hazard intensity at a 1-year return period (annual exceedance probability of 1) and interpolates in log-return-period space between this anchor and the 1:10 year-return interval point. This lower-tail treatment is a modeling assumption and should be interpreted as a pragmatic continuity rule for low-severity thresholds.

Figure 15 and Figure 16 show example hazard curves for ice accretion and wind at the Kingston climate location in 2040 under RCP 6.0. Climate peril intensities between the values contained within the ECCC data are interpolated. As mentioned above, after the 1:200 return interval intensity, the probability of exceedance is assumed to be zero. This is reflected in the truncated x-axes beyond the 1:200 return interval hazard intensities of approximately 36 mm of ice accretion and 115 kph 10-minute average wind speeds. Similarly, the x-axis for both figures begins at the value associated with the 1:10 year return interval, before which point the lower tail treatment approach described above is applied.

[79] Electric Power Research Institute, *Fragility Curves for Quantifying Physical Climate Risk in the Electric Power Sector*, 2025 Available here: https://www.epri.com/research/products/000000003002031792.

Figure 15. Ice Accretion Hazard Curve - Kingston, 2040, RCP6.0

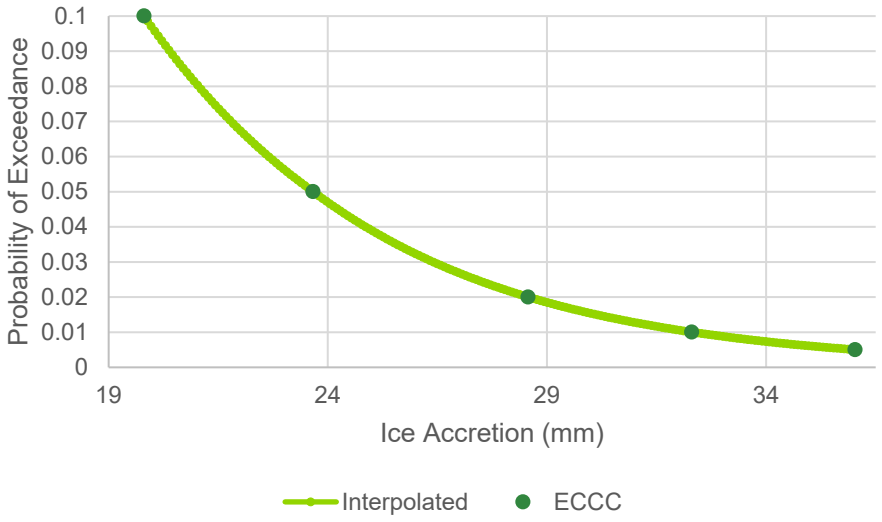
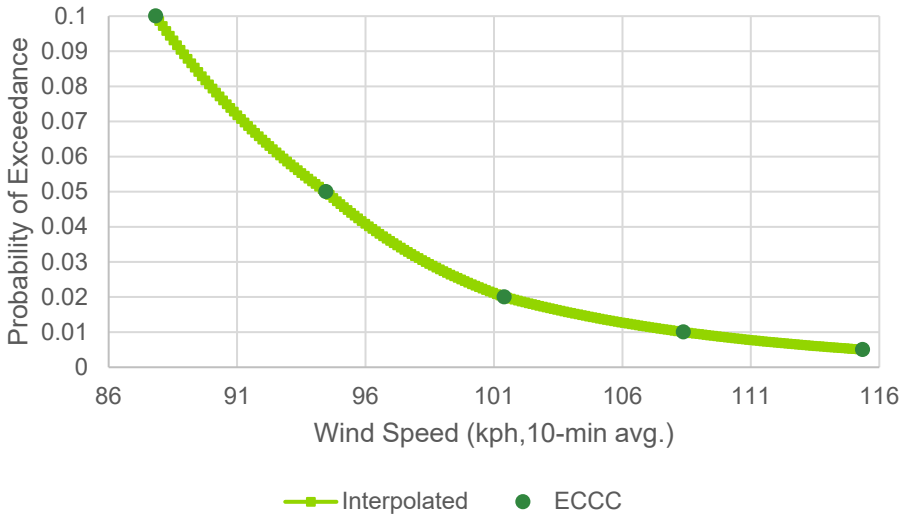


Figure 16. Wind Speed Hazard Curve - Kingston, 2040, RCP6.0



Although Guidehouse scripted the estimation of exceedance probabilities, the output of this analysis delivers the same result as that included in the "3. Climate Severity Calculator" of the generic OEB Toolkit.

Appendix C. Asset and Non-Asset Costs

This appendix provides additional detail regarding the cost assumptions used in the BCA. These values impact both costs (e.g., asset cost) and benefits (e.g., avoided repair and replacement costs) in the BCA.

C.1 Asset Repair and Replace Costs

Hydro One provided Guidehouse with unit costs for the standard assets modelled and the upgraded assets considered for replacement, included in Table 30. The unit costs provided served as a basis for developing asset repair and replacement costs at the asset sub-class level.

Table 30. Asset Unit Costs

Item	Cost (2026$)	Unit
Pole	$14,098	$/unit
Cross arms	$3,051	$/unit
Line transformer	$10,327	$/unit
Bare Conductor Cost	$500,000	$/km
Covered Conductor Cost	$650,000	$/km
Underground Cable	$1,000,000	$/km
M-Class Feeder Switch	$170,000	$/unit
F-Class Feeder Switch	$130,000	$/unit

C.1.1 Pole Costs

For poles, Hydro One informed Guidehouse that poles impacted by *force majeure* events are always replaced. Accordingly, Guidehouse assumed 100% replacement and did not assume repair costs in cases of storm damage. For end-of-life replacement, Guidehouse assumed, per direction from Hydro One that approximately 70% of poles are refurbished at end of life at a cost that is 20% that of replacement.

Pole replacement costs vary based on the type and class of pole. To account for this variation, Guidehouse applied Pole Unit Multipliers developed by the Hydro One Dx Lines Work Management Line of Business for each pole type. Replacement costs by asset sub-class are shown in Table 31 and assume 25% of pole replacements involve the added cost of replacing a line transformer. Guidehouse understands that this assumption is based on the number of pole and transformer replacements that occurred after the high impact (ice storm) event in 2025 (3,088 poles and 759 transformers).

So, for example, for Wood | Class 4 or Worse | On-Road, the pole cost is $14,098 + 0.25 X $10,327 = $16,679.75.

Table 31. Pole Unit Multipliers and Replacement Costs

Asset Sub-Class (Truncated)	Pole Unit Multiplier	Replacement Cost (2026 $)
Wood| Class 3 or Better | On-Road	1.2	$19,499.35
Wood| Class 4 or Worse | On-Road	1	$16,679.75
Wood| Class 3 or Better | Off-Road	1.4	$22,318.95
Wood| Class 4 or Worse | Off-Road	1.15	$18,794.45

The replacement costs above are the assumed capital asset cost of pole replacement as part of the resilience measure (e.g., replacing a Class 4 or Worse pole with a Class 3 or Better pole on-road costs approximately $19,499.35)

Historically, the cost of replacing damaged poles and line transformers is significantly higher after *force majeure* events. Hydro One provided storm multipliers for poles and transformers, yielding a weighted average storm multiplier of 2.69. This multiplier impacts the avoided replacement cost benefit in the BCA.

Hydro One also indicated that on average, for the deferred replacement credit costs (early retirement adjustment), Guidehouse should assume 30% of poles are replaced and 70% are refurbished, with refurbishment costing 20% of replacement. Based on these factors, Guidehouse developed a weighted normal cost for each pole type based on the proportion and cost of poles refurbished vs. replaced. Weighted normal costs are included in Table 32.

Table 32. Pole Weighted Normal Costs

Asset Sub-Class (Truncated)	Weighted Normal Cost (2026 $)
Wood| Class 3 or Better | On-Road	$8,579.71
Wood| Class 4 or Worse | On-Road	$7,339.09
Wood| Class 3 or Better | Off-Road	$9,820.34
Wood| Class 4 or Worse | Off-Road	$8,269.56

The costs above are used as the baseline scenario pole costs. These impact the early retirement adjustment that reduces to total capital cost included in the BCA calculation.

C.1.2 Conductor Costs

The conductor repair and replacement costs in Table 33 were provided by Hydro One and range from $500,000 to $1 million per kilometer. Guidehouse based repair costs on the cross-arm unit cost provided by Hydro One and the average number of poles per kilometer of conductor from the asset data (8.4 poles/km).[80]

The replacement cost for covered conductor and undergrounded conductor is used as the capital asset cost for resilience measure replacement. The replacement cost for bare covered conductor is used to calculate the early retirement adjustment applied for the Covered Conductor and Selective Undergrounding BCA.[81]

[80] This 8.4 poles per km represents the average number of Hydro One-owned poles per *conductor* km rather than per *circuit* km.

[81] For both of these RMs the base assumption is that the RUL of the existing asset is equivalent to the period of analysis for the RM. This means that *no early retirement adjustment* is applied in the core analysis. This cost assumption therefore only impacts the Selective Undergrounding sensitivities demonstrated in Figure 6.4.

For underground conductor, repair costs capture the avoided cost of replacing overhead conductor and are therefore identical to repair costs for overhead assets.

Table 33. Conductor Repair and Replacement Costs

Asset Sub-Class (Truncated)	Repair Cost ($/km)	Replacement Cost (2026 $/km)
Conductor – Bare	$25,628.40	$500,000
Conductor - Covered	$25,628.40	$650,000
UG Conductor	NA	$1,000,000

At Hydro One's direction, Guidehouse assumed that only repairs (i.e., the cost of replacing cross-arms) are applied. Post-storm conductor repair costs are assumed to be significantly higher than planned replacements. Hydro One provided Guidehouse with a storm multiplier of 5.47 for conductor repair cost following *force majeure* events. The application of the storm multiplier to the cross-arm cost is used for the calculation of the avoided repair and replacement benefit.

C.2 Sectionalization Costs

Guidehouse developed sectionalization costs based on cost data provided by Hydro One. The number of locations sectionalized and cost per switch varies by feeder class, with an average of 3 locations and 4.5 locations assumed to be sectionalized for F-Class and M-Class feeders (respectively), respectively.

Switch costs by feeder class are included in Table 34. For both classes, Guidehouse assumed an average of 1.5 poles are replaced and one switch is replaced per location, per Hydro One's direction. The cost of tying the target feeder to an adjacent feeder is estimated as the 1 pole and 1 switch incremental to the other pole and switch replacements, as directed by Hydro One. Guidehouse applied the weighted average pole cost per feeder class based on the existing population of poles. The estimated non-asset capital cost per feeder derived from the values noted above is presented in Table 34. This table also provides the OM&A costs associated with switch maintenance provided by the Distribution Investment Planning Line of Business at Hydro One.

Table 34. Sectionalization Costs

Feeder Class	Cost (2026 $)	OM&A Costs ($/year)
F-Class	$617,170.27	$5,000.00
M-Class	$1,081,673.40	$7,500.00

Appendix D. Benefit-Cost Analysis Components

Section 4.2.4 of the VASH Framework identifies the inputs to the BCA Toolkit. To assist reviewers comparing the work completed by Guidehouse to these inputs,

Table 35. Map of VASH BCA Framework Inputs to Location in Guidehouse Documentation

VASH Framework BCA Input	**Location in Guidehouse Reporting Documentation**
Asset Repair and Replacement Costs	Asset repair and replacement costs (and appropriate replace and repair shares) are documented in Section 3.0 (context for repair or replace shares), Appendix C, and in the tab "4. Generic BCA Inputs" included in each RM's BCA workbook.
Project Characteristics – Project Type (End-of-Life, Early Retirement, Retrofi)	Clustered Hardening, Covered Conductor, and Selective Undergrounding are all Early Retirement projects. Sectionalization and Voltage Conversions and Sectionalization are both Retrofit projects. This is identified in Section 3.0 and in the tab "5. Project Characteristics" included in each RM's BCA workbook.
Project Characteristics – Impact Type (Frequency, Criticality, Both)	Clustered Hardening, Covered Conductor, and Selective Undergrounding are all Frequency impact type. Sectionalization and Voltage Conversions and Sectionalization are both Criticality impact type. This is identified in Section 3.0 and in the tab "5. Project Characteristics" included in each RM's BCA workbook.
Project Economic Variables	Guidehouse has used all the default economic variables included in the published generic Toolkit except for the WACC, for which the value (6.4%) is drawn from the OEB's 2026 Cost of Capital Parameters.[82] These values may be found in the tab "5. Project Characteristics" included in each RM's BCA workbook.

[82] Ontario Energy Board, *2026 Cost of Capital Parameters*, EB-2025-0303, October 2025
https://www.oeb.ca/sites/default/files/OEBLtr_2026%20CoC_20251031.pdf

VASH Framework BCA Input	**Location in Guidehouse Reporting Documentation**
Project Lifetime Variables	These are identified in Section 3.0 and in the tab "5. Project Characteristics" included in each RM's BCA workbook.
Criticality and Value of Lost Load Inputs	These are derived as described in Section 5.1.3, above, and may also be found in tabs: "3. APF Definition" and "5. Project Characteristics" included in each RM's BCA workbook.
Model Calibration Inputs	These are derived as described in Section 5.1.3, above, and may also be found in tabs: "3. APF Definition" and "5. Project Characteristics" included in each RM's BCA workbook. Calibration inputs are drawn from five years of Hydro One's OMS data filtered to include only resilience (*force majeure*) outages, excluding non-relevant cause codes ("Loss of Supply", "Scheduled", "Human Element", "Foreign Interference"), and are mapped to the individual feeders included in the analysis.
Project Asset Map	These values may be found in the tab "5. Project Characteristics" included in each RM's BCA workbook.

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SECTION 3.3 – ATTACHMENT 5.1 - VULNERABILITY ASSESSMENT TOOLKIT

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Hydro One Networks Inc. Electrification Study

2026

PREPARED FOR

Hydro One Networks Inc. (Hydro One)

02/09/2026



Document details

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GLOSSARY

Acronym	Description
ASHP	Air-Source Heat Pump
GSHP	Ground-Source Heat Pump
BEV	Battery Electric Vehicle
PHEV	Plug-in Hybrid Electric Vehicle
HDV	Heavy Duty Vehicle
BtM	Behind-the-meter
DSF	Demand-Side Flexibility
DSR	Demand-Side Response – another term for Demand-Side Flexibility
DER	Distributed Energy Resource, e.g. PV
EE	Energy Efficiency
NZ 2050	Net Zero 2050 Scenario
ST	System Transition Scenario
BAU	Business as Usual Scenario
I&C	Industry & Commercial
GSD	General Service Demand
GSE	General Service Energy

1. Executive Summary

Introduction

Hydro One Networks Inc. (Hydro One) commissioned ERM to deliver this independent study to understand how electrification could shape energy use and peak load on its distribution network between 2030 and 2050, and to identify how cost-effective non-wires solutions, such as energy efficiency (EE), behind-the-meter distributed energy resources (DERs), and demand-side flexibility (DSF), can mitigate reinforcement needs. The analysis focuses on the distribution network exclusively, and excludes the transmission network.

The goal of the study is to provide an independent, scenario-based outlook of future peak load growth and to indicate the qualitative value of potential cost-effective non-wires solutions, without performing project-level cost or net-present value analysis.

Operating costs and upgrade costs in a mature system like Hydro One's would be subject to detailed site-specific feeder-level evaluations. Increases in peak demand above current capacity is used as a proxy for incremental reinforcement system costs in the current study.

ERM has accommodated feedback following an engagement session on November 25th 2025 with key stakeholders, and this has been incorporated into the report as the calculation of the network utilisation rate and the regional analysis presented in Section 7.5 and Section 7.6 respectively.

Scenario framework

Figure 1 introduces the scenario framework used to define the different possible futures for Hydro One's distribution network. Three core scenarios are used:

- Business as Usual (BAU), a baseline scenario where the economy still depends largely on fossil fuels,
- System Transition (ST), which sees widespread electrification with moderate energy efficiency improvements and distributed energy resources rollout, and
- Net Zero 2050 (NZ 2050), where Net Zero goals are met by 2050 and entails significant electrification of all key sectors like heating and transport. This scenario also has the most ambitious efficiency improvements and distributed energy resources rollout.

Two worst-case sensitivities for the System Transition and Net Zero 2050 were also defined to reflect a similar uptake of low-carbon technologies like EVs and heat pumps, but assume minimal improvements in energy efficiency, lower distributed energy resources penetration, and limited incremental demand-side-response. The scenarios are not assigned probabilities; each is used to examine how the different assumptions would impact the peak load projections.

The scenarios were developed to directionally align with government policy, with no single policy being explicitly linked to a unique input dataset. The scenarios were

developed by ERM based on best available information at the time. These scenarios are to be distinguished from load forecasts, which are used for planning, and based on detailed market analysis and specific customer information.

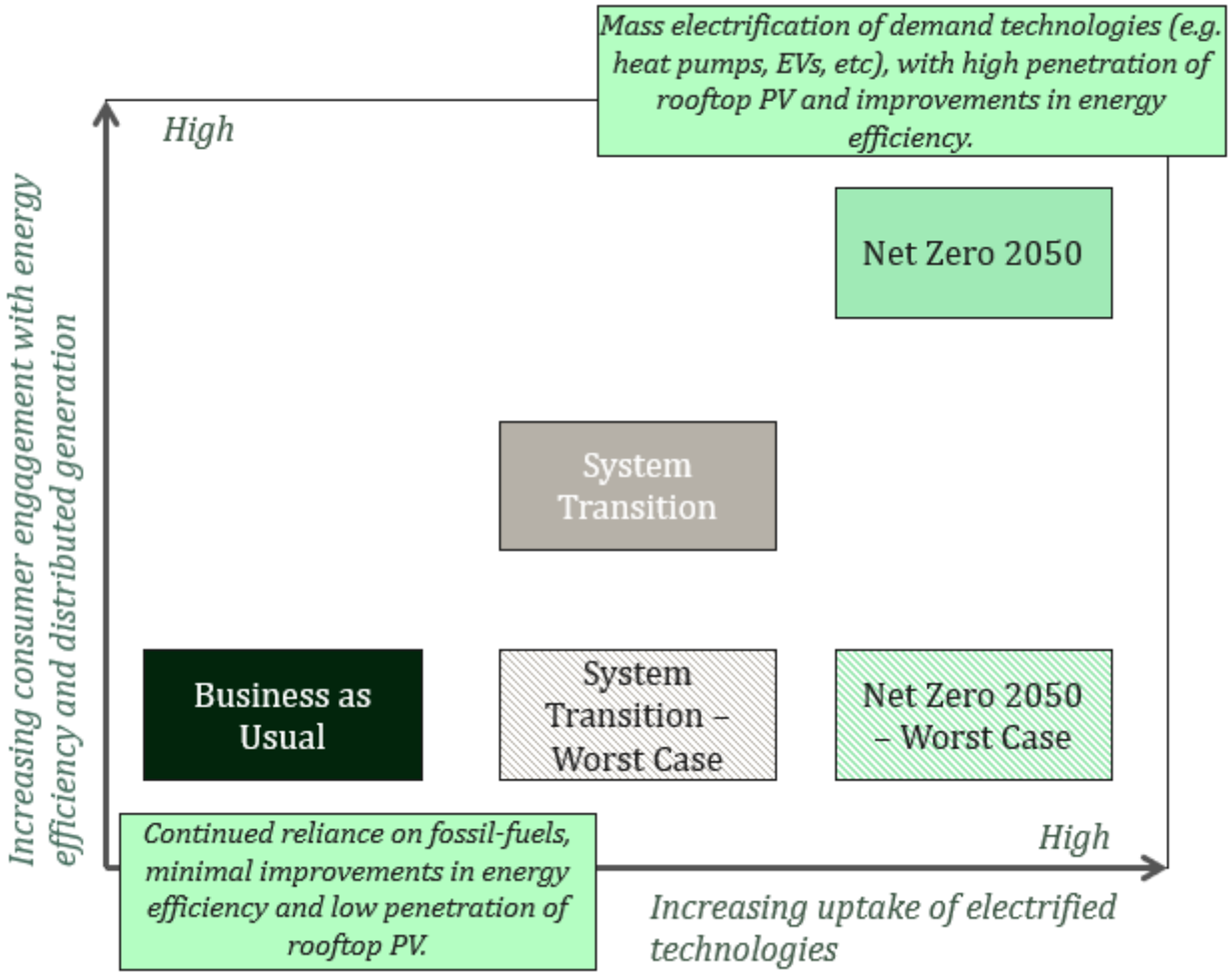


Figure 1: Future energy scenarios and two worst-case sensitivities; scenarios are ordered left-to-right in order of increasing electrification ambition

Electrification drivers

Future changes in energy consumption and peak load are driven by a combination of electrification trends that increase load and mitigating measures that reduce or shift demand. The study models these drivers in a consistent, bottom-up manner across all scenarios, allowing their relative impact on peak load to be isolated and compared. The structured approach to modelling individual electrification drivers was taken as outlined in Figure 2.

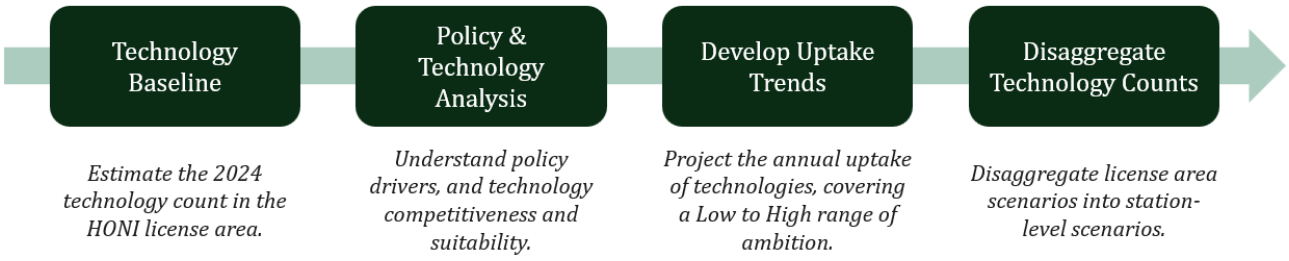


Figure 2: General approach to modelling electrification drivers

The main drivers increasing demand are population and building stock growth, electrification of heat, and electrification of transport, and a near-term pipeline of large I&C customer requests.

Electrification of heat is the single largest long-term driver of peak load growth. Residential and non-residential heating systems are assumed to be replaced at end of life, with technology choice varying by scenario ambition and regional temperature conditions. In colder parts of Ontario, hybrid or ground-source heat pumps are preferred to reflect cold-climate performance constraints. Figure 3 illustrates the scale of heat electrification by scenario: by 2050, around 300,000 additional residential heat pumps are deployed in the Business as Usual scenario, compared with approximately 950,000 in System Transition and 1,050,000 in Net Zero 2050.

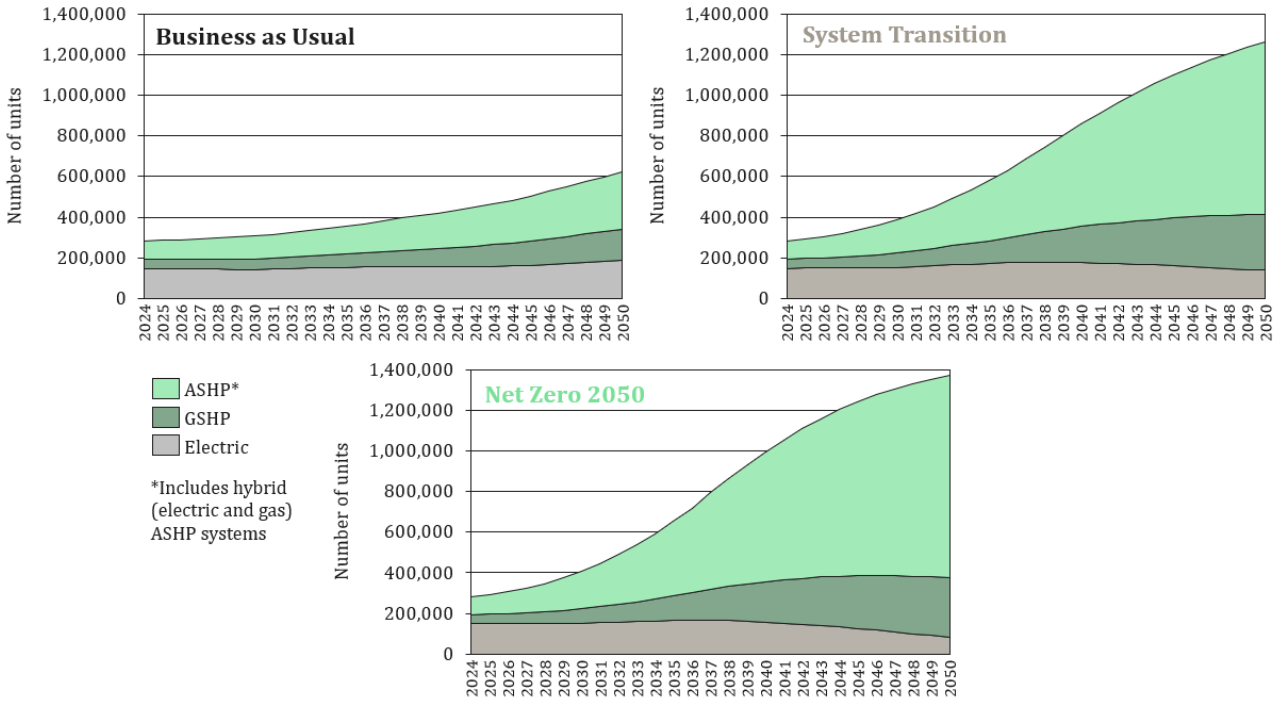


Figure 3: Electric heating technology count projections by scenario

Transport electrification also contributes to rising electricity demand, particularly through the uptake of electric cars and vans. While total energy consumption from electric vehicles increases substantially, their contribution to peak demand increases to a lesser extent. This is because EV charging ramps up in the evening, adding some load to the peak, and peaks at 11pm, outside of peak demand time.

Counteracting these upward increases in demand are energy efficiency improvements, behind-the-meter solar and storage, and demand-side flexibility. Improvements in appliance efficiency and building thermal performance reduce both total energy use and peak heating demand, while rooftop solar and batteries lower net demand, particularly in summer. Demand-side flexibility through active load shifting further reduces peak demand by moving consumption away from hours of peak demand.

Together, these drivers explain why scenarios with similar levels of electrification can result in materially different peak outcomes, and why the coordinated delivery of energy efficiency and flexibility measures plays a critical role in managing future network demand.

Modelling approach

The study uses a bottom-up load modelling approach to translate future electrification trends into changes in electricity consumption and peak demand across the Hydro One distribution network. Figure 4 summarises the key steps in the peak load modelling approach.

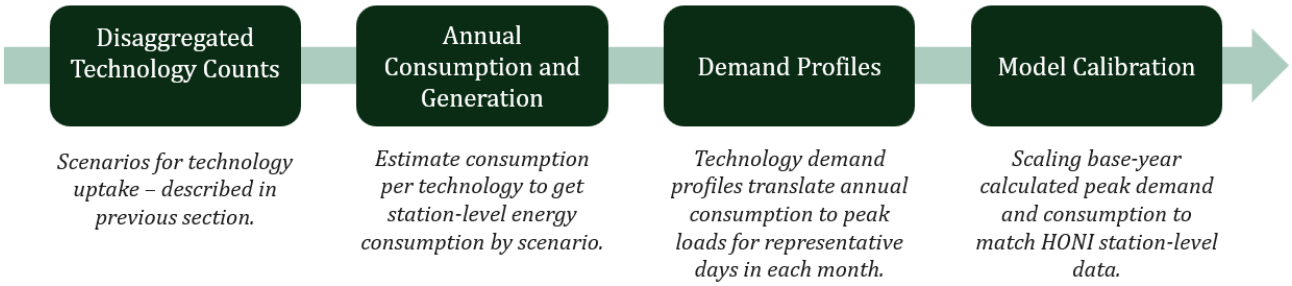


Figure 4: Key steps in estimating future power demand across Hydro One network assets

Electrification drivers are first quantified at a provincial and regional level, including technology uptake, efficiency improvements, and customer growth, and are then spatially disaggregated to individual Hydro One stations.

For each station, annual electricity consumption is calculated by combining technology counts with representative energy use assumptions for residential and non-residential customers. The non-residential baseline values are calibrated to observed station-level consumption to ensure consistency with current network operational data, due to more diverse customer characteristics in that sector.

To calculate the peak load, annual consumption is converted into half-hourly load using normalised demand profiles for each technology and customer type. As an example, the half-hourly profile for residential core demand is shown in Figure 5.

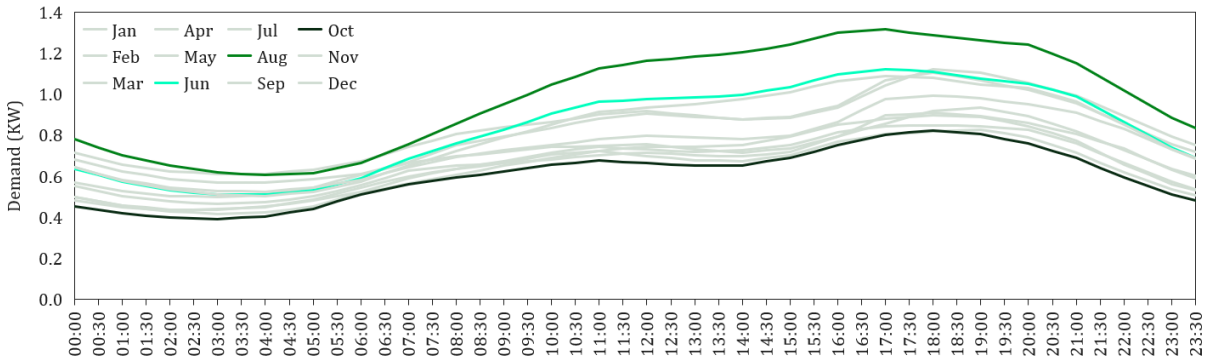


Figure 5: Demand profile for the residential core demand of a detached/semi-detached home in Ontario

These profiles capture seasonal and daily patterns, such as winter heating demand, predominantly evening and overnight electric vehicle charging, and summer air-conditioning. Half-hourly loads are summed across technologies to identify station-level summer and winter peaks, which are then aggregated to produce network-wide and regional peak demand projections.

A near-term pipeline of large I&C customer requests, totalling around 1 GW, is added explicitly to near-term peak load projections. Finally, a network utilisation metric is calculated to assess whether electricity consumption grows faster or slower than peak demand over time, providing additional insight into how effectively network assets are used under each scenario.

Key outputs

As displayed in Figure 6, peak demand is expected to rise over the coming decades across all scenarios, driven primarily by the electrification of heat and transport, as well as by a near-term pipeline of large I&C customer. Hydro One is expected to switch from a summer network peak to a winter peak within the next decade as heating electrifies.

The Business as Usual scenario presents the slowest load growth, reflecting limited uptake of electric technologies. In contrast, both System Transition and Net Zero 2050 show substantially higher peaks, consistent with widespread adoption of heat pumps and electric vehicles.

Notably, the *Net Zero 2050 – Worst-Case* and *System Transition – Worst-Case* sensitivities reveal the significance of energy efficiency, behind-the-meter solar and storage, and demand-side flexibility to mitigate the increase in peak load.

The Net Zero 2050 and System Transition central scenarios converge to similar peaks by 2050. This occurs because the higher electrification rates in Net Zero 2050 are broadly offset by stronger improvements in energy efficiency and higher penetration of behind-the-meter solar and storage. As a result, despite the more ambitious electrification pathway, the network winter peak does not exceed that of System Transition.

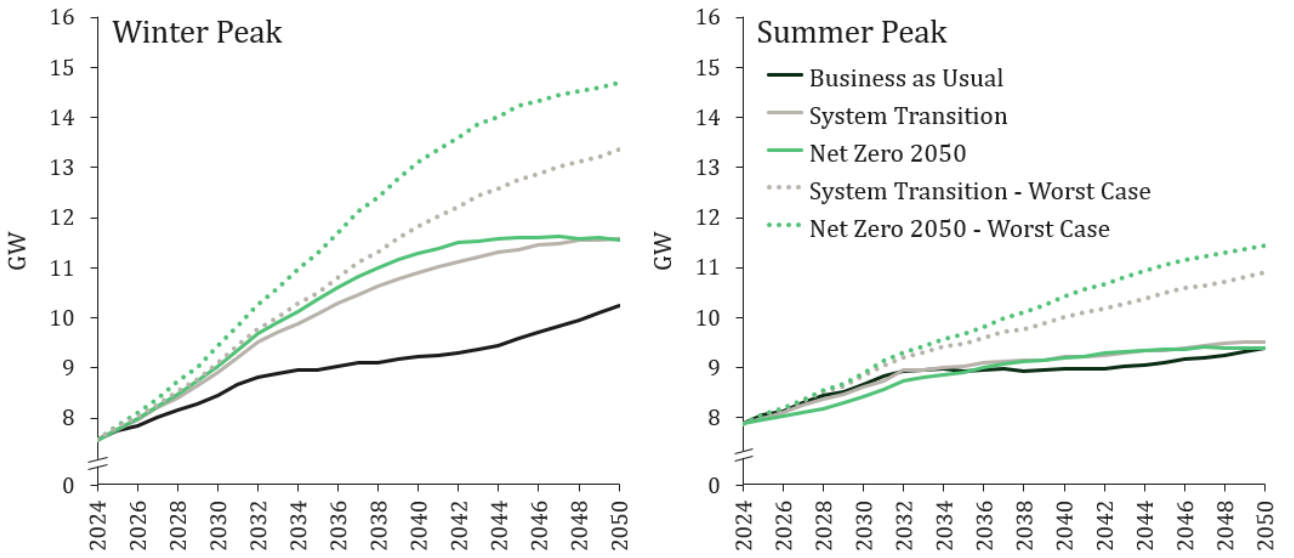


Figure 6: Peak load by scenario and sensitivity for winter (left) and summer (right), 2024 – 2050

By including 'Worst-case' sensitivities for the Net Zero 2050 and System Transition scenarios, it is possible to estimate the difference in system demands that would be seen for an electrified future with less ambitious deployment of these key non-wires solutions. The worst-case sensitivities see the same uptake of electric technologies as their respective electrification pathways, but the same improvements to energy efficiency and solar and storage rollout as the Business as Usual scenario, and no increase in demand-side flexibility.

The sensitivities highlight that future load growth can be influenced significantly by the deployment of these non-wires solutions. The Net Zero 2050 worst-case sensitivity has a 2050 winter peak load that is 27% greater than the Net Zero 2050 scenario, as shown in Figure 7. This is driven primarily by energy-efficiency; in the Net Zero 2050 worst-case sensitivity, 63% of the increase in load is from reduced improvements in core and thermal energy efficiency. A further 31% increase in peak load comes from demand-side flexibility, and 6% from lower uptake of DERs. The relative low contribution seen from DER in the output is due to two competing factors: 1. Solar rollout is actively mitigating the peak demand in hours of sunshine, and 2. because of this, the net demand in these hours goes down, and the new peak demand is seen to happen at later times of the day, where solar generation is lower. As a result, even large rollout of DER is seen to contribute little to lowering the peak demand reported here, in the later hour of the day. This relatively low DER contribution is seen also despite the addition of batteries alongside solar, because the batteries can only charge to their maximum capacity and need to discharge to flatten the peak in all hours where the peak would happen, typically 5-10pm. The need for batteries to discharge in a lot of hours means their overall impact on the peak demand itself is limited, even though it enables a lot of consumption to move away from evening hours.

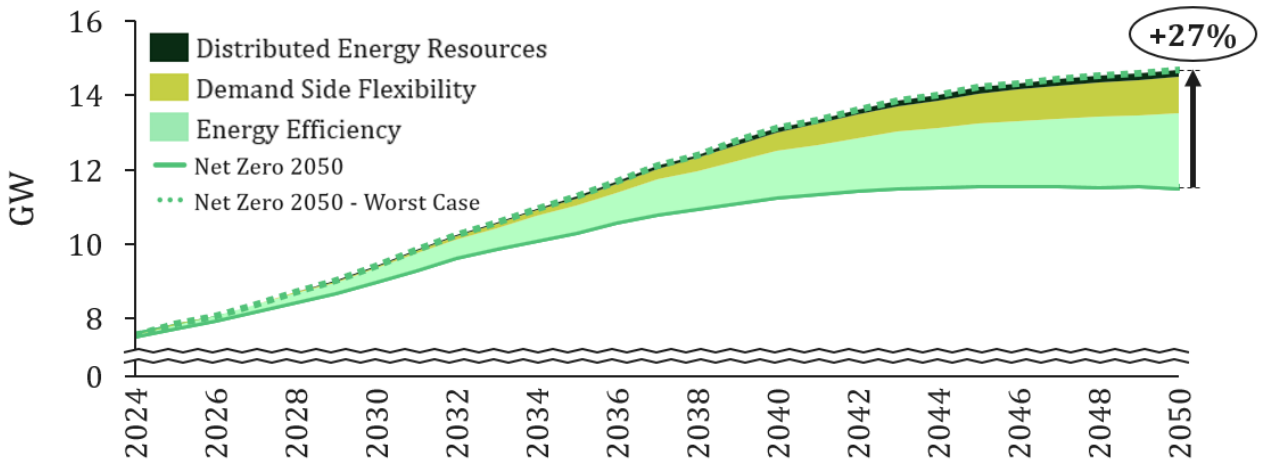


Figure 7: Peak winter load for the Net Zero 2050 scenario and worst-case sensitivity, with driver contributions from Energy Efficiency, Demand Side Flexibility, and Distributed Energy Resources

Conclusion

Across all scenarios, the results show a possible substantial increase in network peak load over the coming decades, driven primarily by the electrification of space and water heating and, to a lesser extent, electric vehicle uptake and new large I&C HV customer connections. The total distribution network peak load is modelled to increase from 8 GW today to up to 15GW by 2050. A key finding is that the Hydro One network is expected to transition from a summer-peaking to a winter-peaking system within the next decade as heating electrifies. Winter evening peaks become the dominant system constraint, while summer peaks shift later into the evening as rooftop solar reduces early evening demand and electric vehicle charging increases evening and overnight consumption.

The analysis highlights that improvements to building thermal performance, appliance energy efficiency and demand-side flexibility could be effective non-wires levers for mitigating the increase in peak load. Behind-the-meter solar and storage can provide additional benefits, particularly for reducing energy consumption and mitigating summer peaks, but their ability to reduce winter evening peaks is more limited. Improvements in network utilisation rate of 15-25% are observed across the different scenarios, indicating that electricity consumption grows faster than peak demand, allowing network assets to be used more intensively over time.

The study establishes an evidenced view on how electrification could reshape future network demand and identifies the conditions under which ambitious decarbonisation pathways can be achieved without proportionally higher peak loads. The results underline the importance of integrating energy efficiency programmes, demand-side flexibility, and distributed energy resources into long-term network operations. These insights can support Hydro One in targeting cost-effective non-wires solutions and prioritising network investments, while detailed cost-effectiveness assessments are undertaken separately using Ontario's established regulatory frameworks on a project-by-project basis.

2. INTRODUCTION

2.1 HYDRO ONE

Hydro One Networks Inc. ("Hydro One") is Ontario's largest electricity distribution operator, serving more than 1.5 million residential, commercial, and industrial customers across a diverse service territory.

Hydro One recognises that Ontario's energy system is undergoing rapid and transformative change. Electrification of transportation, heating, and industry is expected to play a central role in meeting provincial and national decarbonisation objectives. The pace and nature of these changes will be shaped by evolving policy, technological developments, consumer preferences, and regional characteristics.

Hydro One commissioned ERM to develop a set of Future Energy Scenarios and corresponding projections of network load under these scenarios. The scenarios are designed to reflect a range of plausible pathways for Ontario's transition, capturing variations in electrification ambition, customer behaviour, policy direction, and deployment of non-wires solutions.

Hydro One supported the development of the study by providing data and information, as well as regional expertise, to ERM where required. The Future Energy Scenarios and associated modelling were developed independently by ERM, using its established methodologies, sector expertise, and purpose-built modelling tools.

2.2 ENVIRONMENTAL RESOURCES MANAGEMENT (ERM)

ERM is a global sustainability consultancy with established expertise in long-term electricity system modelling, high-resolution load modelling, and future energy scenario development. ERM has supported distribution networks in Canada and internationally on assessing the impact of electrification on their networks.

For this study, ERM applied specialist modelling capabilities and sector expertise to estimate the implications of Ontario-specific electrification drivers on Hydro One's future load growth.

3. STUDY OBJECTIVES

This study was commissioned with the purpose of identifying and modelling electrification trends across the Hydro One distribution network, exploring directional distribution needs, and to provide recommendations for potential cost-effective solutions to the growth in demand within the 2030 to 2050 timeframe.

The three main objectives of this study are:

1. **Scenario Development** – Define a set of plausible future energy scenarios that capture the range of electrification ambitions expected in Ontario from 2030 to 2050.
2. **Model the uptake of electric technologies** – Estimate the future uptake of electric technologies under each scenario, and the associated increase in electricity consumption.
3. **Assess the impact of electrification on Hydro One infrastructure, and provide recommendations for potential cost-effective solutions** – Model the half-hourly load across network infrastructure under the future energy scenarios; understand the impact of electrification on peak load under the future energy scenarios and explore possible cost-effective solutions beyond infrastructure reinforcement.

The key outputs from the study include load and energy consumption projections across a range of scenarios and sensitivities. These outputs enable an assessment of the network impact of different electrification pathways, and the potential contribution of energy efficiency, distributed energy resources (DERs), and demand-side flexibility (DSF) in managing future network needs.

Network reinforcement cost calculations are out of scope for this study for the following reasons:

1. Operating costs and upgrade costs on a mature system like Hydro One's would be subject to detailed site-specific feeder-level evaluations.
2. The Ontario Energy Board (OEB) has established a framework for utilities in Ontario to evaluate cost-effectiveness of non-wires alternatives to network reinforcement, on a case-by-case basis.

The purpose of this study is therefore to provide directional insights into future load growth scenarios and the potential value of non-wires solutions, rather than to undertake a cost–benefit analysis of specific network investments. Increases in peak demand above current capacity is used as a proxy for reinforcement system costs.

4. SCENARIO FRAMEWORK

4.1 OVERVIEW

A scenario framework is a structured approach used to explore and analyse multiple plausible futures, particularly in contexts where significant uncertainty exists for long-term electrification possibilities. The scenario framework enables an assessment of how different levels of electrification, consumer behaviour, and technology adoption might impact the distribution network between now and 2050. By defining distinct scenarios, shown in Figure 8, the framework captures a range of outcomes from business-as-usual to ambitious decarbonisation. These scenarios are not assigned a likelihood or probability of occurring.

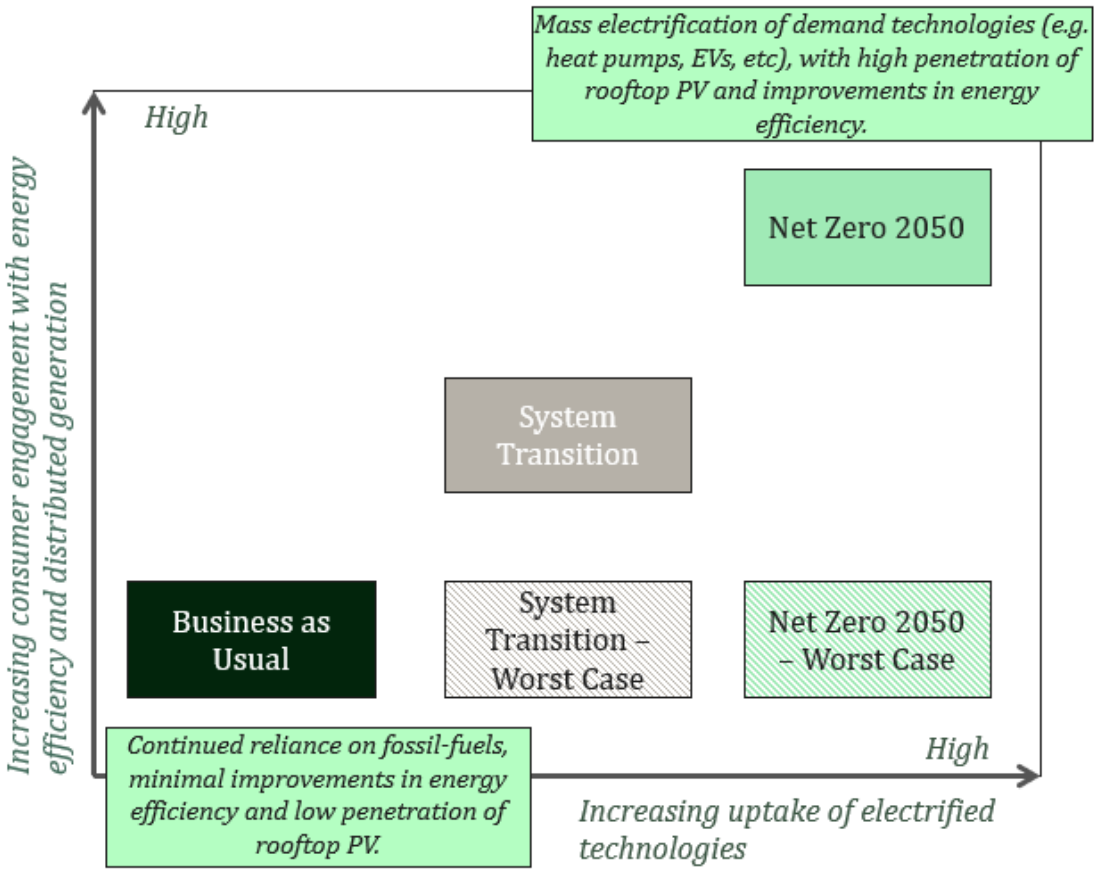


Figure 8: Future energy scenarios and two worst-case sensitivities; scenarios are ordered left-to-right in order of increasing electrification ambition.

Each scenario is built from the bottom up, mapping individual demand drivers, like electric vehicle uptake, heat pump adoption, rooftop solar penetration, and energy-efficiency improvements, to broader system trajectories. This method ensures that the scenarios are grounded in realistic assumptions and data, while still providing flexibility to test sensitivities.

4.2 SCENARIO DEFINITIONS

The Hydro One Electrification Study is built upon three core scenarios, each representing a different possible future for Hydro One's distribution network. The scenarios vary in the level of ambition towards net-zero by 2050, and the two most-ambitious scenarios have 'worst-case' sensitivities, that seek to test the sensitivity of the projections to key policies and demand drivers.

There is no explicit alignment between these scenarios and government policy. The scenarios developed were based on best available information at the time.

The logic behind each scenario is described below. Across the three scenarios, a range in progress towards Net-Zero by 2050 is captured.

In the **Net Zero 2050** scenario, there is the near-complete electrification of demand technologies, and high levels of consumer engagement with low-carbon technology.

There are considerable improvements made to building efficiency, and there is high uptake of behind-the-meter generation and storage. There is mass uptake of heat-pump systems and electric vehicles. Consumers participate actively in demand-side flexibility.

A **Net Zero 2050 – Worst-Case** sensitivity was also calculated. In this sensitivity, the ambitious uptake of electric technology remains the same, but there is minimal improvement in energy-efficiency, and low penetration of distributed generation and storage. There is no increased consumer participation in demand-side flexibility compared to today.

In the **System Transition** scenario, there is mass electrification of demand technologies, and high levels of consumer engagement with low-carbon technology.

There are moderate improvements made to building efficiency, and there is moderate uptake of behind-the-meter generation and storage.

The gas-grid continues to operate, and so there is residual use of gas furnaces in the heating sector. Some consumers leave their gas furnaces installed upon installing a heat pump, or choose to install a hybrid gas-ASHP system, for cold winter days.

While the vast majority of vehicles are electrified by 2050, with all vehicle sales being electric or plug-in-hybrids by 2035, there is still a large number of hybrids on the road in 2050, and therefore some reliance on fossil-fuel for mobility. Consumers participate actively in demand-side flexibility.

A **System Transition – Worst-Case** sensitivity was also incorporated. The same uptake of low-carbon technology is projected, but there is minimal improvement in energy-efficiency, and low penetration of distributed generation and storage. There is no increased consumer participation in demand-side flexibility compared to today.

The **Business as Usual** scenario sees the least amount of societal change and makes slow progress towards net-zero.

Improvements to energy-efficiency continue at the historic rate, and there is low uptake of rooftop solar and other distributed energy resources.

Battery electric vehicles and plug-in hybrids continue to be competitive forms of transport, but only reach 70% of car sales by 2050.

The gas grid continues to operate cost-competitively, remaining the dominant heating fuel in 2050.

Consumers participate actively in demand-side flexibility (this is common across all three core scenarios)

These scenarios are to be distinguished from load forecasts, which are used for planning, and based on detailed market analysis and specific customer information.

The individual driver modelling is mapped to the scenarios as outlined in Figure 9. Some demand drivers, such as demand-side flexibility and building stock growth, were kept constant across scenarios, allowing for the impact of key end-use drivers to be isolated and evaluated.

Within the scenario framework, demand-side flexibility is treated differently from other demand drivers because its future impact is shaped by a combination of behavioural, technological, market, and regulatory factors that are difficult to represent through a simple low–medium–high progression. As a result, ERM decided to reflect demand-side flexibility as either present or limited within the scenarios, rather than scaling its impact incrementally.

Demand Driver		Business as Usual	System Transition	Net Zero 2050	System Transition – Worst Case	Net Zero 2050– Worst Case
Building Stock Growth		Ontario Ministry of Finance Projection				
Core Energy Efficiency		Low	Medium	High	Low	Low
Thermal Energy Efficiency		Low	Medium	High	Low	Low
Electrified Heating Uptake		Low	Medium	High	Medium	High
Electric Vehicle Uptake		Low	Medium	High	Medium	High
Behind-the-meter Solar		Low	Medium	High	Low	Low
Behind-the-meter Storage		Low	Medium	High	Low	Low
Demand Side Flexibility		Increased role of DSF to mitigate peaks			No increased role of DSF compared to today	

Figure 9: Mapping individual demand drivers to scenarios and sensitivities.

5. ELECTRIFICATION DRIVER MODELLING

A structured approach to modelling individual electrification drivers was taken as outlined in Figure 3. Electrification drivers refer to low-carbon technologies that use or produce electricity as their main fuel, such as heat pumps, EVs, solar PV or batteries.

First, the baseline asset stock is identified through Ontario publicly available datasets and Hydro One-owned data. This includes, for example, the number of buildings, data on building demand and existing heating systems, number of cars and buses, etc. This forms a picture of how energy is currently being used across Ontario, including the number of electric demand technologies (e.g. heat-pumps, EVs, etc), how they are geographically distributed, and also the number of non-electric technologies that could be candidates for future electrification.

Second, future growth trends for electrified technologies are developed through a combination of policy analysis, stakeholder engagement, and modelling of consumer uptake (e.g. purchasing of electric technologies).

Finally, Low-carbon technologies growth trajectories are disaggregated to individual Hydro One stations, enabling an assessment of how localised technology uptake impacts network infrastructure.

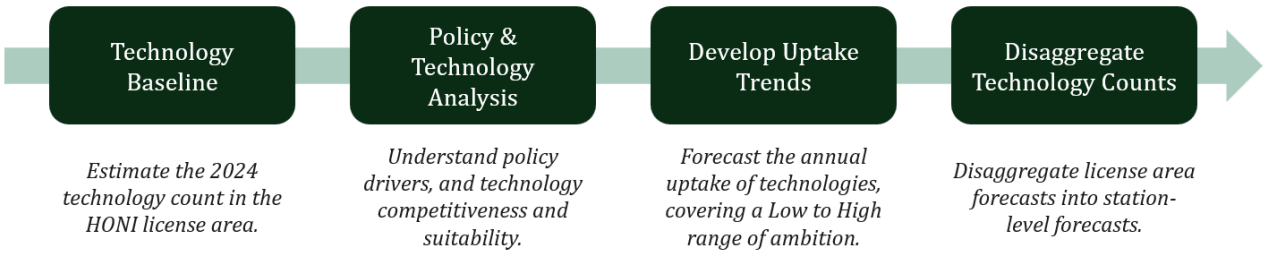


Figure 10: General approach to modelling electrification drivers.

The following sections outline in detail the specific modelling approach for key electrification drivers.

Drivers that act to decrease peak load:

- Energy efficiency improvements
- Distributed generation and storage
- Demand side flexibility

Drivers that act to increase peak load:

- Electrification of heat
- Electrification of transport
- Building stock growth
- Expected commercial and industrial demand connections

Single large demand sites like data centres were excluded from this study because they lead to a large increase in demand that cannot be predicted or modelled accurately without site specific knowledge, which was unavailable for the study.

5.1 CONNECTIONS GROWTH

The population of Ontario is forecasted to grow in the coming decades, through a combination of natural population growth and migration. This will drive an increasing number of connections to the distribution network and could likely result in an increase in power demand. There is also a near-term pipeline of large I&C customer planning to connect to the distribution network in the coming years.

5.1.1 BUILDING STOCK GROWTH

The Study assumes a proportional increase in the number of households in line with the Ontario Ministry of Finance (MOF) central population forecast [1], while industrial and commercial (I&C) buildings are assumed to increase in proportion to the increase in the working age population. The MOF forecasts a 35% increase in the total population and a 31% increase in the working age population in Ontario from 2024 to 2050 (Figure 11).

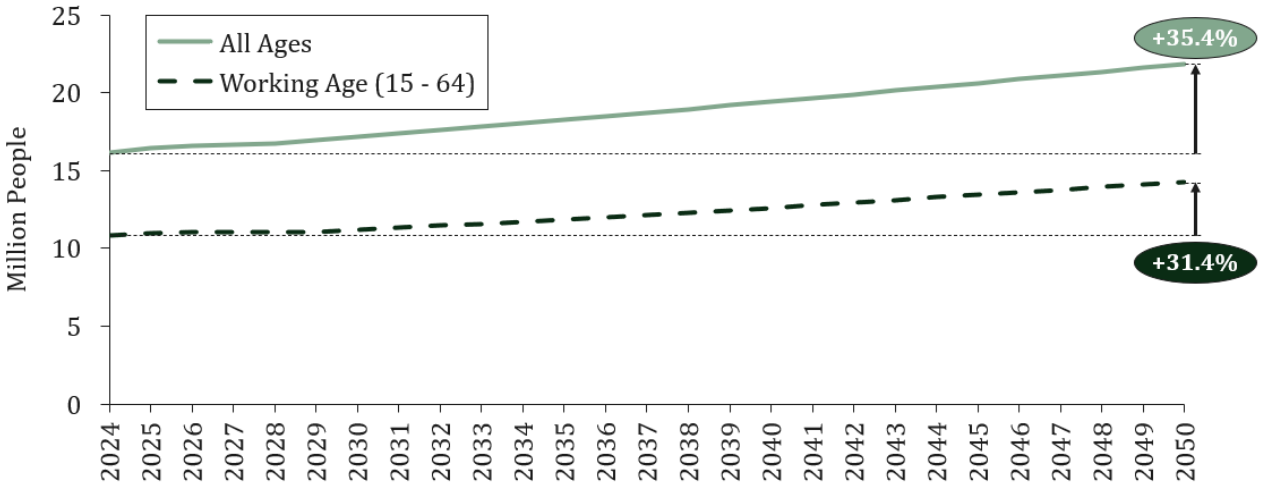


Figure 11: Forecasted population growth in Ontario

Regional variations in population growth were accounted for by using the MOF projections at Census Division. These were applied to Hydro One customer counts at stations to arrive at final Hydro One customer counts change projections to 2050.

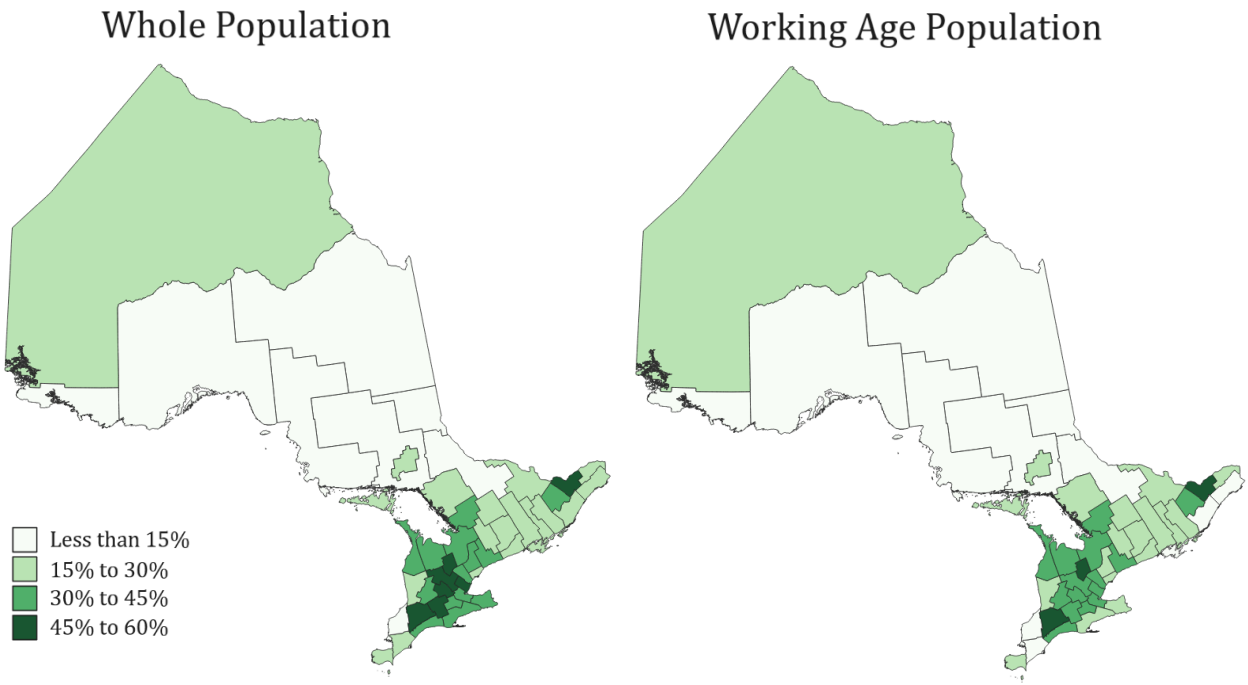


Figure 12: Percentage population growth, 2024 to 2050, for Ontario census divisions (MOF projections).

5.1.2 LARGE I&C CUSTOMER CONNECTION PIPELINE

Hydro One data on large-demand customer requests was used to estimate near-term growth in I&C connections. It is assumed that the current pipeline of connection requests, totalling 1,051 MW of peak demand, will be fulfilled over the next eight years. That dataset is provided at station-level directly from Hydro One.

5.2 ENERGY EFFICIENCY

Households and businesses in Ontario continue to consume energy more efficiently, through upgrades to their appliances and building fabric. Projected improvements to energy-efficiency were divided into core and thermal efficiency. Core demand refers to energy demand from anything apart from heating, for example appliances, lighting, or air-conditioning. Thermal demand refers to demand for space and water heating only.

5.2.1 CORE ENERGY EFFICIENCY

Appliances, air-conditioning units, and lighting are expected to become increasingly efficient over time. Energy efficiency projections were developed for both residential and non-residential core demand. For the residential sector, the analysis considered the turnover of household appliances to high-efficiency models. For the non-residential sector, projections assumed retrofit rates for commercial buildings.

Residential Core Efficiency

Figure 13 lists all appliance types included in the modelling of residential core demand. The impact of residential core efficiency was modelled by assuming that different proportions of all appliances are being upgraded to newer and more efficient systems at end of life, across the different scenarios.

Base year core demand per household in Ontario was estimated using the Natural Resources Canada (NRCAN) Comprehensive Energy Use Database [2]. NRCAN data on the number of appliances per household and the average appliance energy consumption was used to estimate share of household core demand from appliance categories. Energy Star Canada data on appliance lifetimes [3] was then used to estimate a turnover rate for each appliance type.

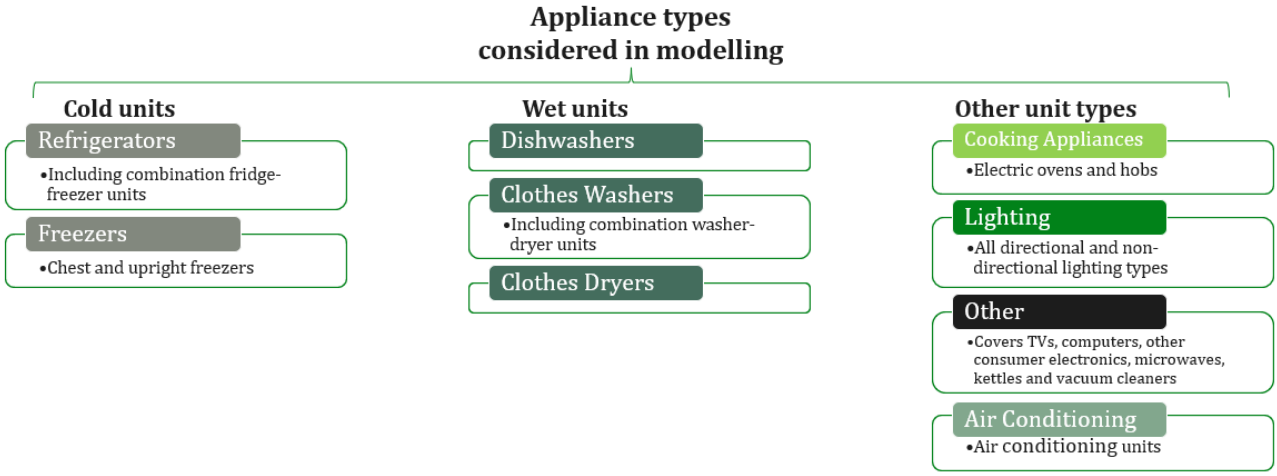


Figure 13: Appliances considered in residential core demand modelling.

At appliance end of life, a proportion of appliances will be replaced with a highly efficient model; the remaining appliances are replaced with a model of average efficiency, with the average appliance efficiency incrementally improving each year in line with the historic rate. The energy consumption of highly efficient appliances was taken from the Energy Star 'Most Efficient Product' database [4]; the model logic is summarized in Figure 14.

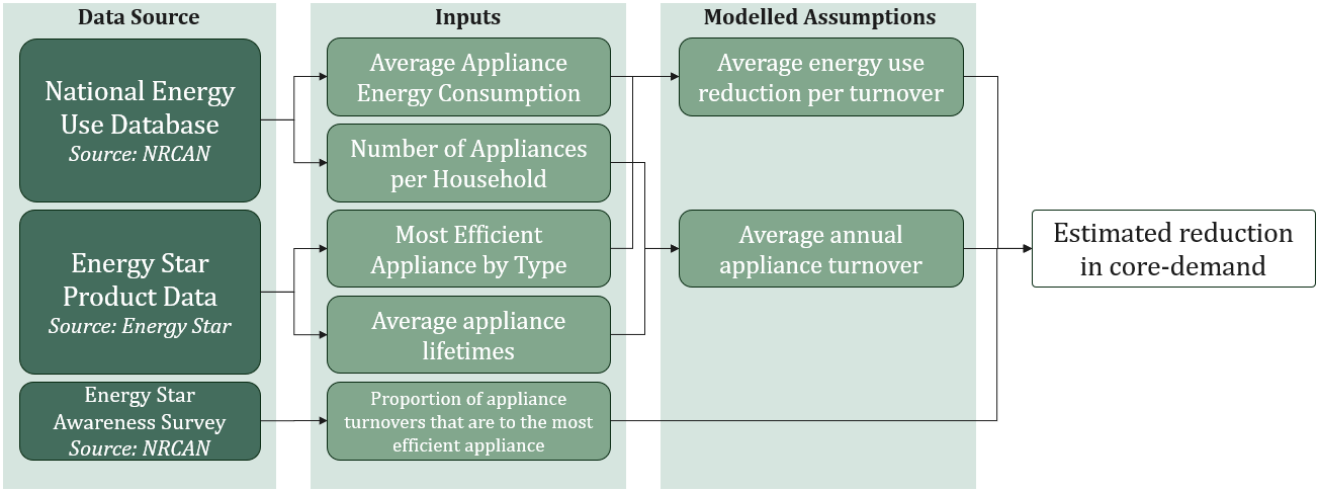


Figure 14: Model logic for residential core demand energy efficiency projections.

An estimated 7.3% of Ontario consumers currently purchase the most-efficient product on the market when replacing appliances, based on an Ipsos study of awareness of Energy Star products [5]. The Business as Usual scenario and the Worst-case scenario sensitivities assumes this rate of replacement continues to 2050, while

System Transition and Net Zero 2050 see an increase to 11% and 15%, respectively, in the rate of replacement with most-efficient appliances at end of life (Table 1).

Table 1: Core residential demand energy efficiency assumptions

Scenario	Rate of turnover to most-efficient appliance at end of life	Relative Decrease in Core Energy Demand per Household in 2050
Business as Usual and Worst-Case Sensitivities	7.3%	7%
System Transition	11.0%	19%
Net Zero 2050	14.6%	23%

The average Ontario household was estimated to use between 3.3 and 6.3 MWh per year for appliances, lighting, and cooling [2]. Modelling appliance turnover as described, this is expected to lead to a decrease in core energy demand between 7% and 23% per household by 2050.

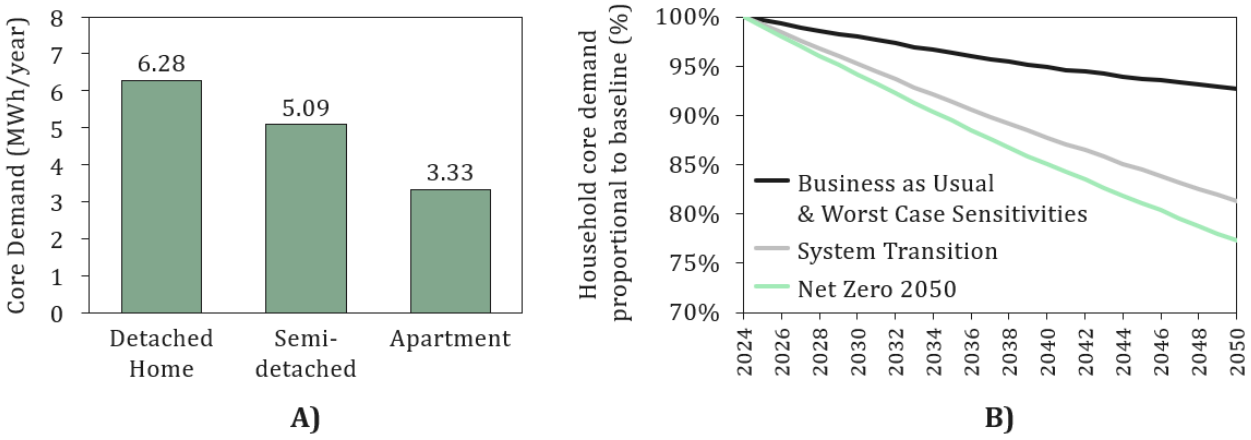


Figure 15: (A) Average baseline demand from appliances, lighting, and cooling in Ontario households [2]. (B) Estimated decrease in core demand in Ontario households through energy-efficiency improvements.

Non-Residential Core Efficiency

Due to the greater variety in the end-use of industrial and commercial core demand, a generalized approach was taken in the estimation of energy efficiency improvements for non-residential buildings. NRCANs National Energy Use Database (NEUD) [6] data was used to baseline commercial and industrial energy demand in Ontario by end-use category.

Research from Efficiency Canada [7] on typical demand reduction post-retrofit for commercial buildings (Table 2) was used to estimate the reduction in energy demand for I&C customers.

Table 2: Post-retrofit demand reduction estimates for non-residential buildings [7].

End-use	Estimated Reduction in Demand post retrofit
Lighting	20%
Space Cooling	10%
Equipment	20%
Motors	50%
Space Heating	35%

A range of assumptions on retrofit rates was selected to capture low to high ambition in future retrofitting of non-residential buildings. Assumed retrofit rates, and corresponding demand reductions, are described in Table 3. These assumptions reflect either a continuation of historic trend, for the Business as Usual scenario, or an increase in ambition that would be needed in both other scenarios. The core energy demand change is aligned with projections performed by ERM across other geographies and in other electrification studies. The annual reduction in thermal demand relative to baseline is seen in Figure 16.

Table 3: Core non-residential energy efficiency assumptions

Scenario	Proportion of commercial properties retrofitted by 2050	Relative Core Energy Demand Decrease by 2050
Business as Usual and Worst-Case Sensitivities	*Continuation of historic trends in I&C core energy efficiency, 20%*	8%
System Transition	40%	14%
Net Zero 2050	75%	26%

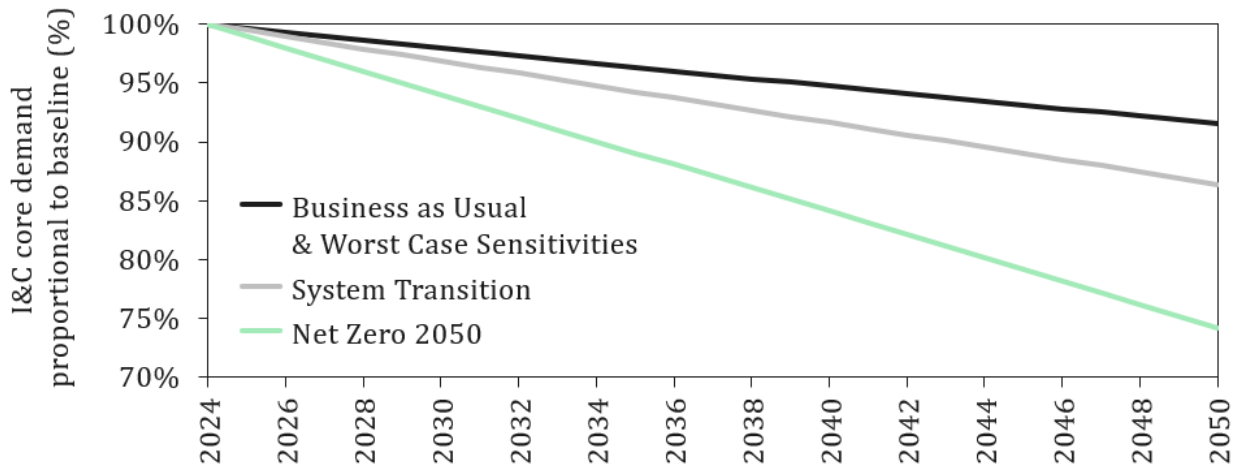


Figure 16: Estimated Core Energy demand relative to the baseline for non-residential buildings.

In the case of non-residential core demand, the core efficiency improvement trajectories were applied to a baseline for I&C core demand derived from Hydro One's own data for the demand of I&C customers at different voltage levels[1] and NRCAN data on the split of electrical demand between core and thermal demands.

5.2.2 THERMAL ENERGY EFFICIENCY

The majority of building energy use in Ontario is due to space and water heating. Heating energy demand is expected to decline as homes and businesses become more efficient through improved thermal insulation. Energy demand reduction for heating can also happen through switching to more efficient technologies (i.e. heat-pumps); this is captured separately through electrification of heat modelling (Section 5.3).

Thermal energy efficiency improvements are modelled with the following steps:

1. Define building archetypes.
2. Estimate the baseline thermal demand of the building archetypes.
3. Estimate the thermal demand of each archetype after a retrofit has been carried out.
4. Estimate the rate of building retrofits.

This process and the outcomes are described in detail in the following sections.

Residential thermal energy efficiency

Residential thermal demand in Ontario was baselined with the NRCAN National Energy Use Database (NEUD) [6]. Research from Efficiency Canada [7] on typical demand reduction post-retrofit for residential buildings was used to estimate the reduction in energy demand for each residential retrofit. A rate of retrofitting was assumed for each scenario as described in Table 4. These assumptions reflect either a continuation of historic trend, for the Business as Usual scenario, or an increase in ambition that

[1] Considering General Service Demand (GSD), General Service Energy (GSE) and Sub-Transmission Direct (ST Direct) customers. GSD customers have peak demand of 50kW or higher, GSE customer peak demand is less than 50kW and ST Direct customers are >500kW peak demand.

would be needed in both other scenarios. The core energy demand change is aligned with projections performed by ERM across other geographies and in other electrification studies.

Table 4: Residential building retrofit rate assumptions and corresponding thermal demand decrease.

Scenario	Proportion of residential properties retrofitted by 2050	Relative Thermal Energy Demand Decrease by 2050
Business as Usual and Worst-Case Sensitivities	18% (in line with historic rate of 0.7% retrofits/year [7])	9%
System Transition	25%	12%
Net Zero 2050	50%	24%

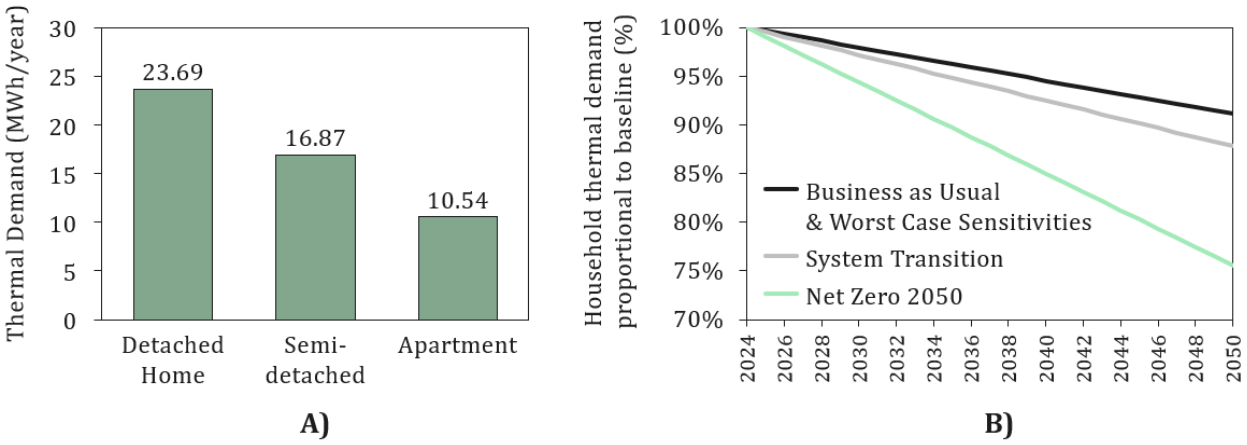


Figure 17: (A) Average baseline demand from space and water heating in Ontario households. (B) Estimated decrease in thermal energy demand in Ontario households through energy-efficiency improvements.

Non-residential thermal energy efficiency

Non-residential thermal energy efficiency improvements were modelled in line with the method described in Section 5.2.1. Average post-retrofit energy savings from Efficiency Canada for space and water heating were applied using the same retrofit rates in the Core energy efficiency modelling. Baselining was completed using the NRCAN National Energy Use Database. Estimated reductions in thermal energy demand per non-residential building can be seen in Figure 18. As in the case of core demand efficiency, these trajectories are applied to baseline thermal demand estimates derived from Hydro One's data and NRCAN assumptions on electricity consumption for thermal demands.

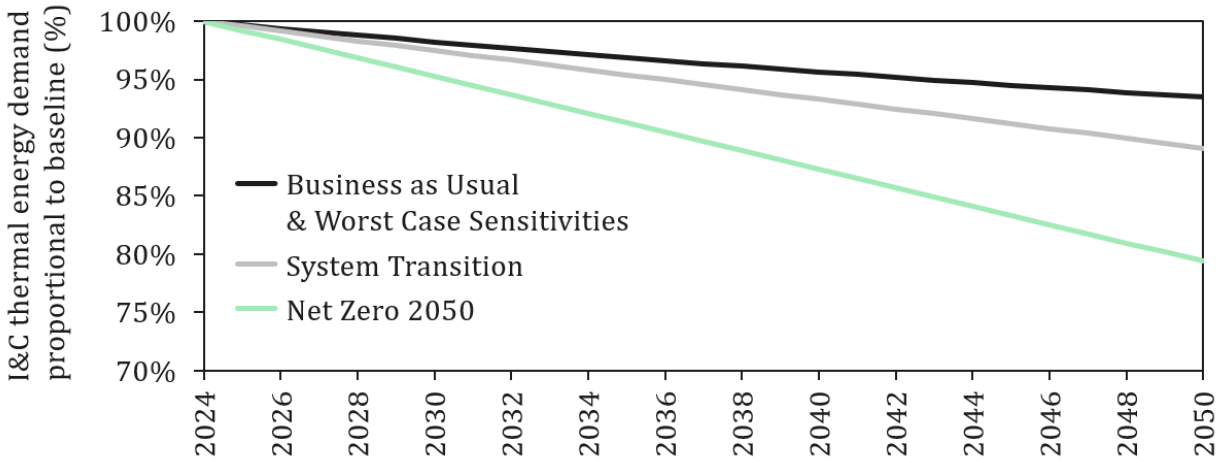


Figure 18: Estimated Thermal Energy demand relative to the baseline for non-residential buildings.

5.3 ELECTRIFICATION OF HEAT

Building space and water heating can be decarbonised through electrification or the use of low-carbon fuels. The analysis in this study focuses on predicting the uptake trajectories of electrified heating technologies, specifically air-source and ground-source heat pumps (ASHP and GSHP, respectively), hybrid heat-pump systems, and resistive electric systems (electric), because these have a direct impact on power grids, whereas others do not. District heat networks were excluded from scope, as Hydro One's largely rural distribution area is less suited to the dense heat loads required for viable district energy systems.

The heating futures for each scenario is described below:

Scenario	Narrative
Business as Usual and Worst-Case Sensitivities	Continuation in historic heat electrification trends. The gas grid remains operational and cost-effective in 2050, with natural gas continuing to supply most heat in Ontario. Other fossil fuel heating systems (oil/propane) are near phased out by 2050.
System Transition	Strong progress is made towards electrification, but some hard-to-heat homes remain on fossil-fuel systems in 2050. Some homes in colder regions of Ontario leave their gas heating systems in place alongside the installation of a heat-pump system, to supply additional heat in the coldest weeks. Oil/propane heating systems are phased out by 2050.
Net Zero 2050	Complete electrification of heat in Ontario, with the gas distribution network decommissioned by 2050. Homes in colder regions opt for ground-source heat pumps, electric resistive, or hybrid electric resistive air-source heat pump systems (i.e. electric resistive heaters alongside an air-source heat pump)[2].

5.3.1 RESIDENTIAL HEAT

This section outlines the modelling methodology and results for the pathways of residential heat electrification in Hydro One's service area.

Temperature Considerations

Ontario experiences significant variation in winter temperatures due to its expansive geography; southern regions are comparatively mild, while northern areas experience sub-arctic conditions. Large parts of the province regularly see winter temperatures fall below -20°C for extended periods of time. Although modern cold-climate air-source heat pumps can operate at these temperatures, their efficiency declines in extreme cold. Homes with sub-optimal thermal insulation may opt for supplemental heating systems (either electric or fossil fuels) in these periods, or a ground-source heat pump, which can operate more efficiently at low air temperatures [8].

Weather station data from 1990 to 2020 was used to find the average number of January days (which is typically the peak heating month) where the lowest recorded

[2] Hybrid heat pump systems can include a gas heater or an electric resistive heater alongside an air source heat pump. In the Net Zero 2050 scenario the gas system is completely decommissioned by 2050, so hybrid heat pump systems can only be heat pumps with electric resistive heaters.

temperature was below -20°C (Figure 19). In the electrified heating uptake modelling, Hydro One customers that experienced more than 5 January days with temperatures sub -20°C were only assigned a hybrid-heat pump system or a ground-source heat pump.

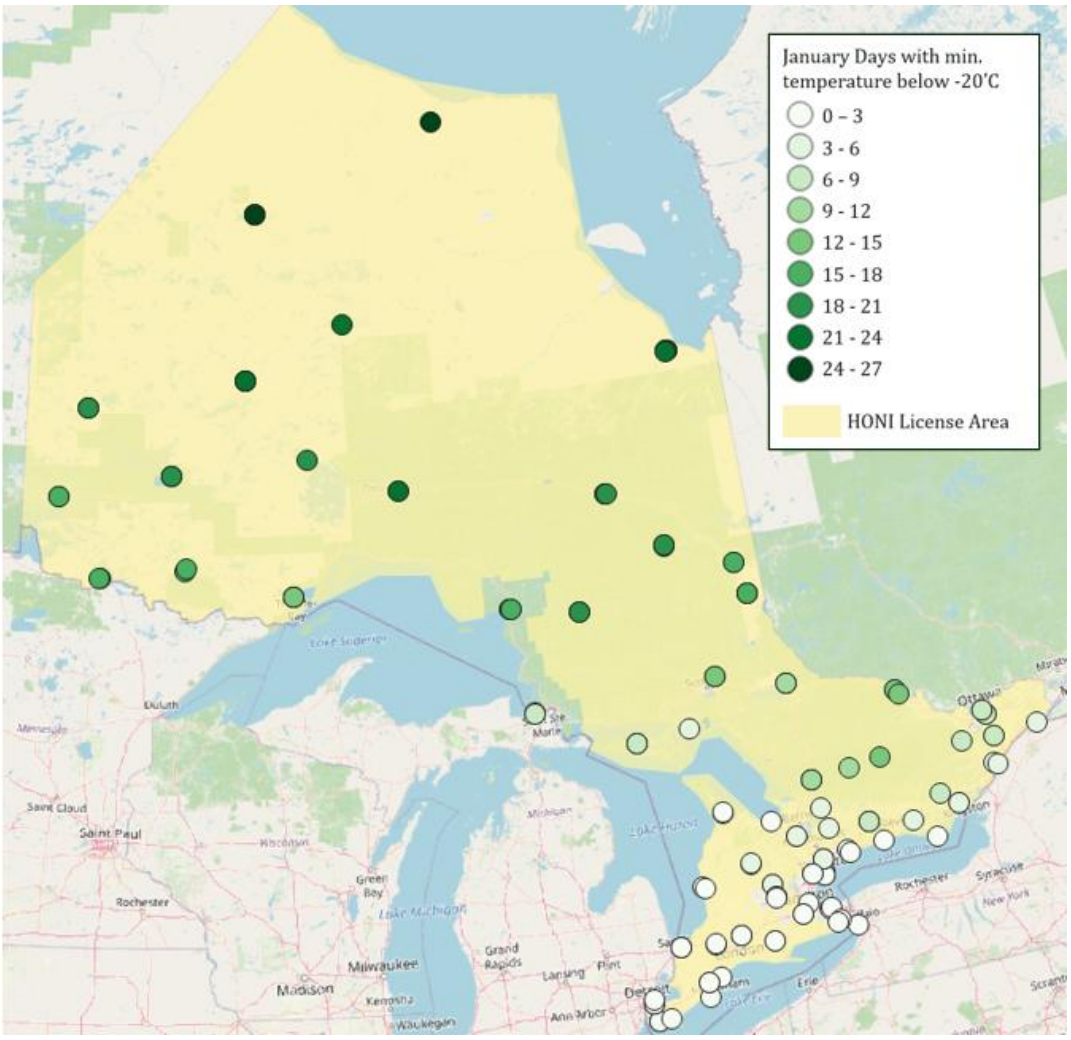


Figure 19: Average number of January days with minimum temperatures below -20'C according to weather station data, 1991-2020 [9].

Building Stock Archetyping

To understand how the Ontario building stock might electrify its supply of heat, the building stock was first divided into a set of representative archetypes. The stock was divided based on

- House type (detached/semi-detached and apartments),
- Current heating technology fuel (natural gas, other fossil fuels, and electric technologies), and
- Connection to the gas grid.

The stock dataset was aggregated through a combination of Hydro One customer survey data, NRCAN energy data, and 2021 Census data on building type.

Around half (49%) of residential buildings in Hydro One's service area rely on natural gas furnaces to heat their homes, suggesting that nearly 90% of those with access to the gas network have gas furnaces[3] (Figure 20). One quarter of Hydro One's customers use other fossil fuel systems to heat their home, with the remaining 24% already using electric technologies.

Hydro One's customer base is described by ten building archetypes, as shown in Figure 21. The majority (89%) of homes are detached or semi-detached properties. The typical Hydro One customer is a detached/semi-detached property with a gas heating system (43%), with the next most common archetypes being detached/semi-detached properties using electric (22%) or other fossil fuel heating systems (19%).

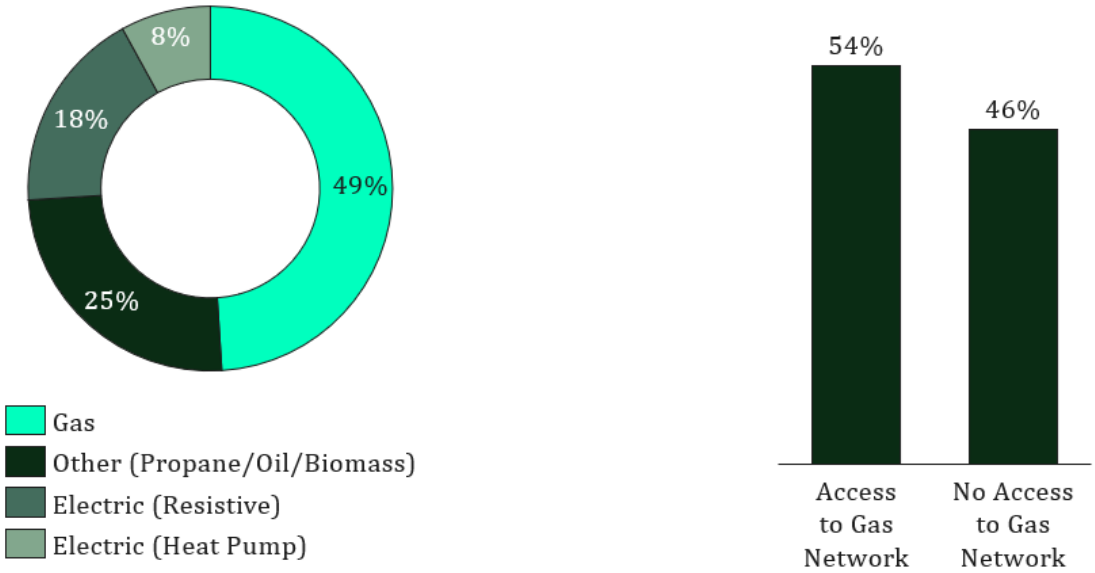


Figure 20: Estimated heating technology split of Hydro One's residential customer base in 2024 (left). Proportion of homes with/without access to the gas distribution network (right).

[3] The 49% of homes with a gas furnace is approx. 90% of the 54% of homes that have access to the gas network.

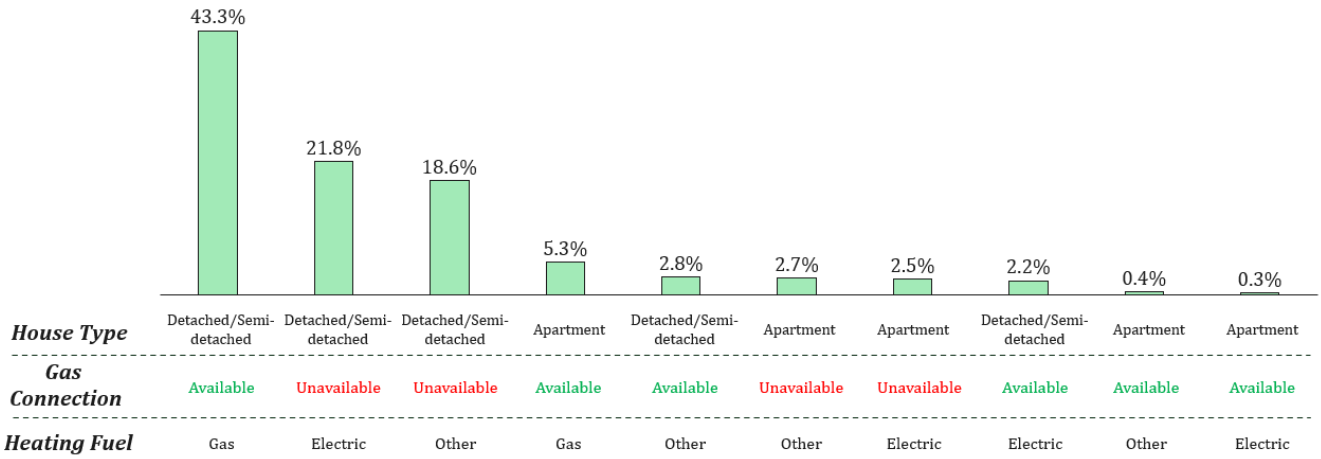


Figure 21: Breakdown of residential building archetypes; 89% of buildings are detached or semi-detached properties, with around 54% connected to the gas grid.

Modelling Assumptions

Uptake scenarios for residential heating technologies were estimated by projecting sales trends across building archetypes. Buildings are assumed to replace their current heating technologies only at end of life, with the choice of replacement technology being influenced by archetype and the policy and market environment.

The Key Modelling Assumptions used to achieve this are:

- Heating technologies are on average replaced **every 12 years**.
- Homes that are not currently connected to the gas network **do not connect** in future. This is because the impact of OEB gas rollout programmes is expected to be too low to be significant for this modelling exercise.
- In future, policy may be introduced in Ontario to limit the installation of fossil fuel heating systems; assumptions as to when this occurs are outlined in Table 5.
- Buildings in colder regions of Ontario will only install **hybrid or ground-source heat pumps** for heating.
- **No new-builds install an oil or propane heating system after 2030**, instead opting for natural gas or electric systems.

Across scenarios, policy interventions are introduced in different years to incentivise the phase-out of fossil fuel heating systems. Separate phase-out dates are assumed for natural gas vs oil/propane heating systems, described in Table 6.

Table 5: Year in which *existing* buildings can no longer install fossil fuel heating systems.

Existing Heating Fuel	Business as Usual and Worst-Case Sensitivities	System Transition	Net-Zero 2050
Gas	No restrictions	No restrictions	2039
Oil or LPG	2049	2039	2035

New residential buildings are treated separately, with the assumption being that policy introduced to restrict the installation of fossil-fuel heating systems is likely to target new-builds ahead of existing buildings. Additionally, oil and LPG heating is typically uneconomical so avoided for new-builds without the need for explicit policy. For example, Montréal has introduced a ban on combustion heating in new buildings [10].

Table 6: Year in which *new* buildings can no longer choose fossil fuel heating systems. It is assumed that no new buildings in Ontario have oil/LPG systems installed after 2030.

Heating Fuel	Business as Usual and Worst-Case Sensitivities	System Transition	Net-Zero 2050
Gas	No restrictions	2050	2035
Oil or LPG	2030	2030	2030

Modelling Results

Across all scenarios, the number of electric heating technologies is projected to increase significantly across Hydro One's service area. A total of 220,000, 1,100,000, and 1,300,000 additional residential heat-pumps are expected to connect to Hydro One's distribution network by 2050 in the Business as Usual, System Transition, and Net-Zero 2050 scenarios respectively (Figure 22). Resistive electric systems remain roughly as popular in 2050 as in 2024 in the Business as Usual scenario, with 190,000 systems in 2050. The prevalence of resistive electric systems decreases in System Transition (140,000) and Net Zero 2050 (80,000), with customers more likely to switch over to more efficient heat-pump systems as economies of scale bring down installation costs.

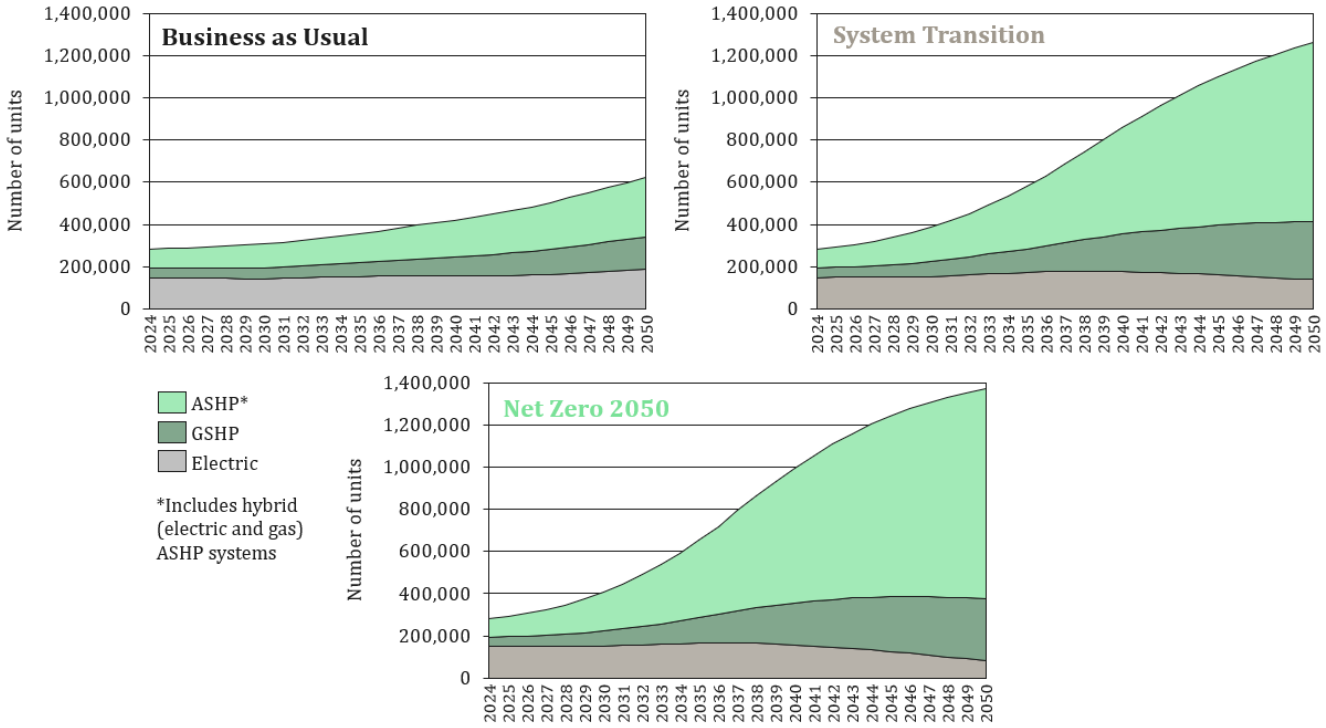


Figure 22: Electric heating technology count projections by scenario.

5.3.2 NON-RESIDENTIAL HEAT

The electrification of non-residential heat is modelled using the same overarching methodology applied to residential buildings. Uptake trajectories incorporate regional winter temperature patterns to reflect variations in technology suitability across Ontario.

Building Stock Archetyping

Hydro One non-residential customer archetypes were used in the modelling of heat electrification. These are based on the voltage level of their connection:

Archetype	
General Service Energy (GSE)	<50KW Peak Demand
General Service Demand (GSD)	≥ 50KW Peak Demand
Sub-transmission Direct (ST Direct)	>500KW Peak Demand

The electrification of sub-transmission Direct (ST Direct) connections was considered out of scope; these customers represent large industrial connections. A site-by-site analysis of these connections and their routes to decarbonisation is required to fully understand future power demands from these sites. ST Direct demand was treated as a fixed baseload.

Modelling Assumptions

Baseline heating technology counts were taken from the Natural Resources Canada (NRCAN) energy use database [2]. Varying ambitions in the phase-out of fossil fuel heating was set across scenarios. In the Business as Usual (BAU) scenario, gas remains the most prominent fuel for heating non-residential buildings in 2050. In the System Transition (ST) scenario, 20% of non-residential buildings already built in 2024 use gas heating in 2050. Gas is phased out completely by 2050 in the Net Zero 2050 (NZ 2050) scenario. The proportion of fossil-fuel heating systems in key years for the existing non-residential building stock are outlined in Table 7.

Table 7: Proportion of non-residential customers with Gas and Other Fossil Fuel heating systems by scenario in 2024, 2030, and 2050.

	Gas			**Other Fossil Fuel**		
	BAU	ST	NZ 2050	BAU	ST	NZ 2050
2024	92%			4%		
2030	89%	75%	75%	3%	2%	0%
2050	80%	20%	0%	0%	0%	0%

A range of ambitions were captured across scenarios for the electrification of new-non-residential builds (Table 8). It was assumed that no new I&C buildings would be constructed with oil or propane heating systems, owing to the low number of existing non-residential buildings in Ontario that currently opt for these heating systems.

Table 8: Proportion of non-residential new builds with Gas and Other Fossil Fuel heating systems by scenario, 2024, 2030, and 2050.

	Gas			**Other Fossil Fuel**		
	BAU	ST	NZ 2050	BAU	ST	NZ 2050
2024*	90%	80%	80%	0%		
2030	70%	50%	40%	0%	0%	0%
2050	40%	0%	0%	0%	0%	0%

**constructed in 2024*

Modelling Results

Projected uptake of electric heating technologies across non-residential buildings are presented in Figure 23. Between 28,000 and 110,000 electric heating systems are projected to supply heat to non-residential customers across Hydro One's service area.

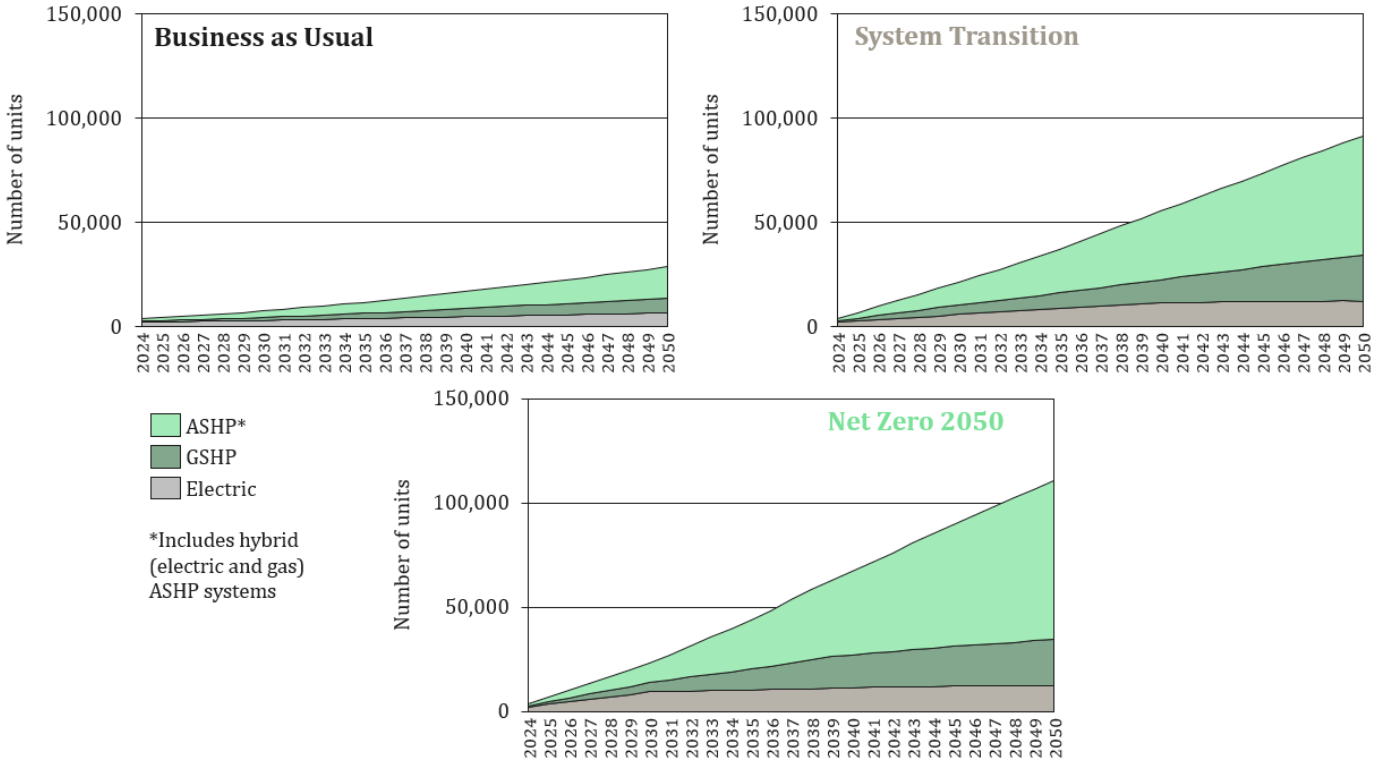


Figure 23: Projected non-residential heating technology by scenario

5.4 ELECTRIFICATION OF TRANSPORT

Uptake trajectories were developed for the electrification of a range of vehicle types, including cars, vans, heavy duty vehicles (HDVs), and buses. Three levels of ambition were captured in the projected uptakes for each technology, reflecting the study's scenarios approach.

5.4.1 VEHICLE STOCK BASELINE AND GROWTH

Transport electrification was modelled by modelling the proportion of vehicle sales each year that were low-emission. A baseline number of vehicles and expected growth in the stock was therefore estimated, shown in Figure 24. The growth in the stock, together with assumptions for the rate of replacement of vehicles in the existing stock (a varying replacement rate was assumed for vehicles of different ages), combined to determine a number of new vehicle sales per year (this varies by year, but is approximately 10% of the existing stock).

An estimated 1,400,000 cars and 280,000 light-trucks exist across Hydro One's service area as of 2024 [11], with an average of 1.58 vehicles per household [12]. It is assumed that the total car and light truck stock will increase by 30% from 2024 to 2050, aligned with the population growth projection in Ontario. In the base year, 2% of the total vehicle stock are electric vehicles [13].

There are 20,000 active transit buses in Ontario as of 2024 [11]. Just 16 of 180 bus stations in Ontario are in the Hydro One service area, it is therefore assumed that approximately 1,800 buses operate within Hydro One (scaling proportionally to the number of bus stations). No increase in the total number of buses in the Hydro One service area is modelled.

There are 145,000 heavy duty vehicles (HDVs) in Ontario, estimated to increase to 190,000 by 2040[4] [14]. Of the 503 truck fuel stops in Ontario, 213 are in Hydro One's service area. It is therefore estimated that in 2024 there are 61,500 HDVs across Hydro One, increasing to 91,200 by 2050[5]. No BEV HDVs are modelled as operating in Hydro One in the base year.

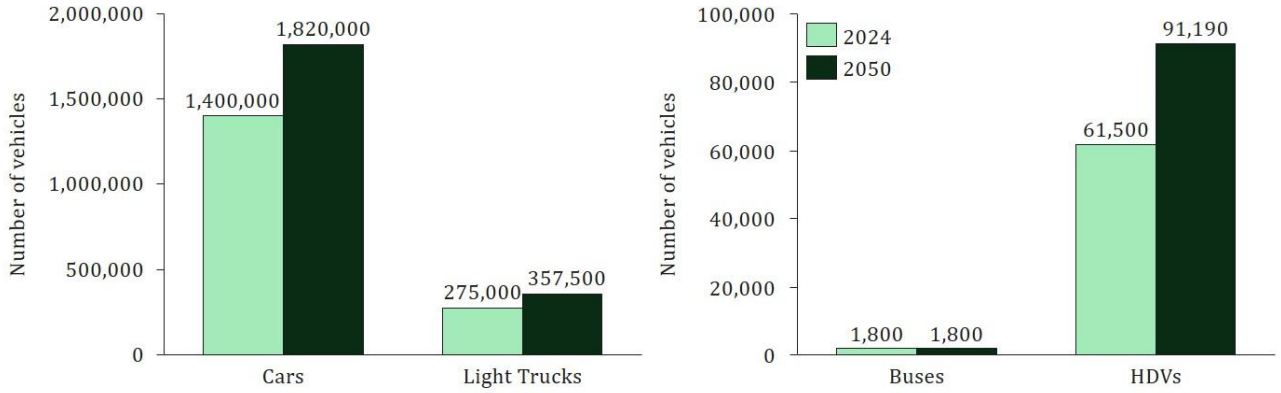


Figure 24: Estimated number of vehicles by vehicle type, Hydro One service area, 2024 and 2050.

5.4.2 CARS AND LIGHT TRUCKS

A range of ambitions for car and light-truck electrification is reflected in the three uptake trajectories. The Business as Usual scenario aligns to the Canadian National Electrification Assessment's baseline scenario [15]. The System Transition and Net Zero 2050 scenarios align to the Emission Reduction Plan (ERP) targets of 20% ZEV sales in 2026, 60% by 2030, and 100% in 2035[6]; Net-Zero 2050 sees a higher proportion of vehicles as fully electric (BEVs) compared to the System Transition scenario. Proportions of vehicle sales in 2030, 2035, and 2050 are found in Table 9.

[4] It is assumed that the rate of increase in HDV stock modelled by Ebrahimi et al. continues to 2050, reaching 215,000 HDVs in Ontario by 2050.
[5] Assuming that the proportion of Ontario's HDVs that are in Hydro One's service area is equal to the proportion of truck fuel stops that are in Hydro One's service area.
[6] The policy mandate on which this assumption was based has changed after the study was performed.

Table 9: Proportion of car and light truck sales that are battery-electric vehicles (BEV) and plug-in-hybrid vehicles (PHEV) in 2030 and 2050.

	Battery-electric vehicles (BEV)			**Plug-in hybrid electric vehicles (PHEV)**		
	BAU	ST	NZ 2050	BAU	ST	NZ 2050
2030	10%	35%	45%	15%	25%	15%
2035	20%	50%	75%	25%	50%	25%
2050	50%	70%	100%	20%	30%	0%

The resulting EV uptake projections (Figure 25) estimate 780,000 to 2,100,000 BEVs and 78,000 to 840,000 PHEVs by 2050.

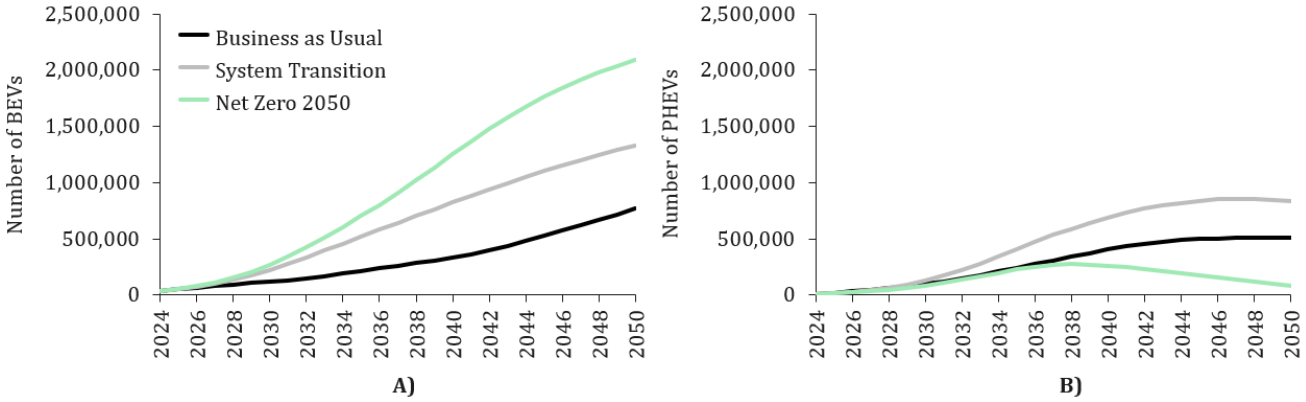


Figure 25: Number of BEV (A) and PHEV (B) cars and light-trucks in Hydro One's service area.

5.4.3 BUSES

There are 2,600 electric buses planned to be deployed across Ontario [16]. The uptake scenarios define different years by which this deployment pipeline is fulfilled (Table 10), and the ambition in long-term bus sales proportions that are BEV or PHEV (Table 11).

Table 10: Year in which the current pipeline of electric buses is fulfilled; Ontario pipeline is scaled to Hydro One service area using bus stations.

BAU	ST	NZ 2050
2035	2030	2028

Table 11: Estimated proportion of bus sales that are BEV or PHEV in 2035 and 2050.

	BEV			**PHEV**		
	BAU	ST	NZ 2050	BAU	ST	NZ 2050
2035	20%	50%	90%	0%	0%	0%

2050	20%	95%	100%	0%	5%	0%

In Net Zero 2050 the Hydro One bus stock is fully electrified. System Transition makes strong progress towards full electrification, while in the Business as Usual scenario 20% of the bus stock is assumed to be electrified[7] (Figure 26).

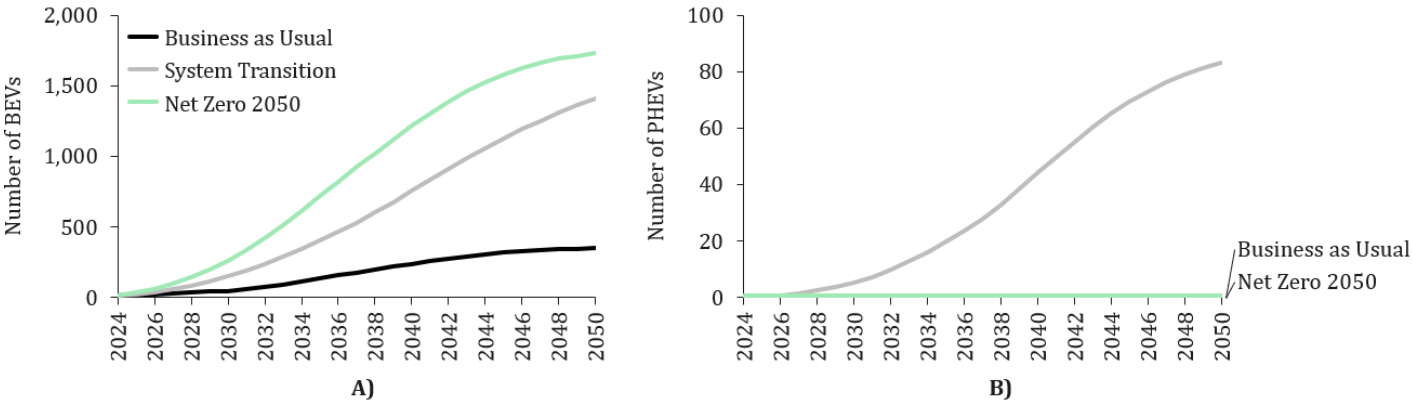


Figure 26: Number of electric (A) and plug-in hybrid (B) buses in Hydro One's service area.

5.4.4 HEAVY DUTY VEHICLES

In the Business as Usual scenario, 23% of the HDV stock is electrified by 2050. This aligns to the IESO 2025 Annual Planning outlook [13]. Greater ambition for the electrification of HDVs is seen in the System Transition and Net Zero 2050 scenarios, reaching 100% EV sales by 2045 and 2040 respectively. Sales milestones are provided in Table 12, with corresponding trajectories in Figure 27.

[7] Based on the conservative assumption that 2,600 currently planned battery electric buses (BEB) are delivered by 2035 and that the BEB market share remains constant at 20% of new sales from 2035 to 2050.

Table 12: Proportion of medium- and heavy-duty truck sales that are battery-electric vehicles (BEV) and plug-in-hybrid electric vehicles (PHEV) in 2030, 2035, and 2050.

	BEV			PHEV		
	BAU	ST	NZ 2050	BAU	ST	NZ 2050
2030	2%	3%	34%	0%	3%	1%
2035	7%	5%	62%	0%	12%	6%
2050	40%	90%	95%	0%	10%	5%

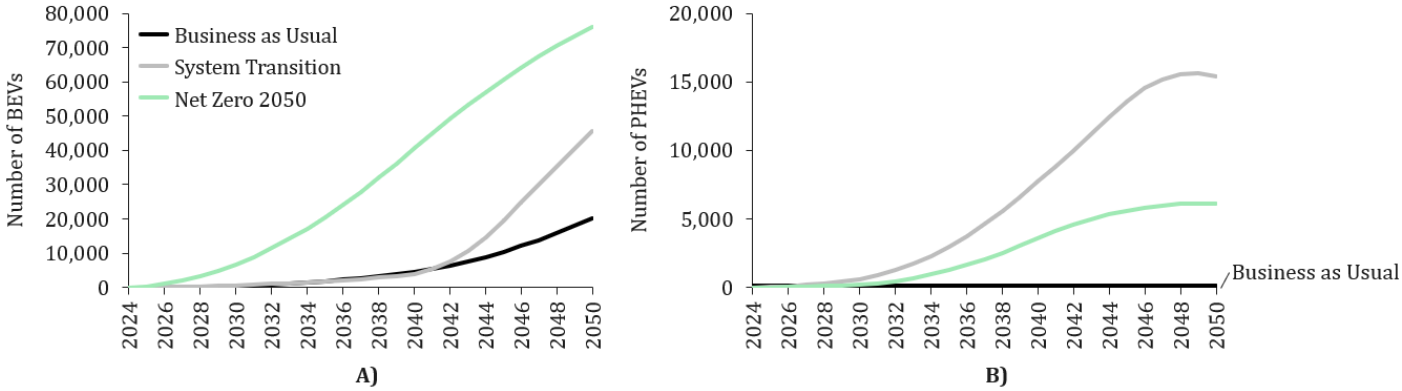


Figure 27: Number of electric (A) and plug-in hybrid (B) medium- and heavy-duty trucks in Hydro One's service area.

5.4.5 CHARGING DISTRIBUTION

Spatially mapping charging demand from electrified road transport goes beyond assigning load to vehicle registration locations. BEV and PHEV cars may charge at home, at destinations, or en-route, meaning demand must be distributed across these locations using different charging profiles. The allocation of demand therefore reflects a set of assumptions on charging behaviour for cars, buses, and HDVs, as outlined in the following section.

5.4.5.1 CARS AND LIGHT TRUCKS

BEVs and PHEVs (both cars and light trucks) are first assigned to a home address, where demand from home charging is assigned. This was carried out using vehicle registration data from Statistics Canada [17]. Uptake modelling for BEVs and PHEVs was carried out at service area resolution and then disaggregated to census subdivisions. In the near term, EV uptake is weighted to regions that already have higher proportions of EVs. By 2050, however, the model assumes that BEVs and PHEVs are evenly distributed across all households.

An estimated 87% of Hydro One residential customers live in detached or semi-detached properties [18] and are therefore assumed to have access to off-street charging. In addition, many EV drivers that do not have private off-street parking

(e.g. garage or driveway) will be able to charge at near-home locations (e.g. on-street chargers). Modelling therefore assumes that 90% of EV charging in Hydro One's service area is completed at public AC (alternating current) or home charge points, as both home or near-home on-street charging happens predominantly in the evening and overnight, with the same charging profile. The remaining 10% of charging demand is modelled to be completed at public DC (direct current) charge points (rapid/high voltage). These public DC chargers are distributed based on existing fuel station locations, from OpenStreetMap's Overpass Turbo API3 [19] weighted by local population data and traffic flow data by region from the Ontario Ministry of Transportation [20].

5.4.5.2 MEDIUM AND HEAVY TRUCKS

HDVs were assumed to do the majority of their charging at their depot, as charging at depots is significantly cheaper than charging on the public network [21]. Hydro One data on large industrial connections was taken as a proxy for depot locations.

5.4.5.3 BUSES

Buses are assumed to charge exclusively at existing bus depots, located using OpenStreetMap data [19]. Urban or local buses are likely to charge at their depot, while buses that cover greater distances are likely to charge at a depot at the end of their routes. In either case, charging at depots will cover the majority of bus charging.

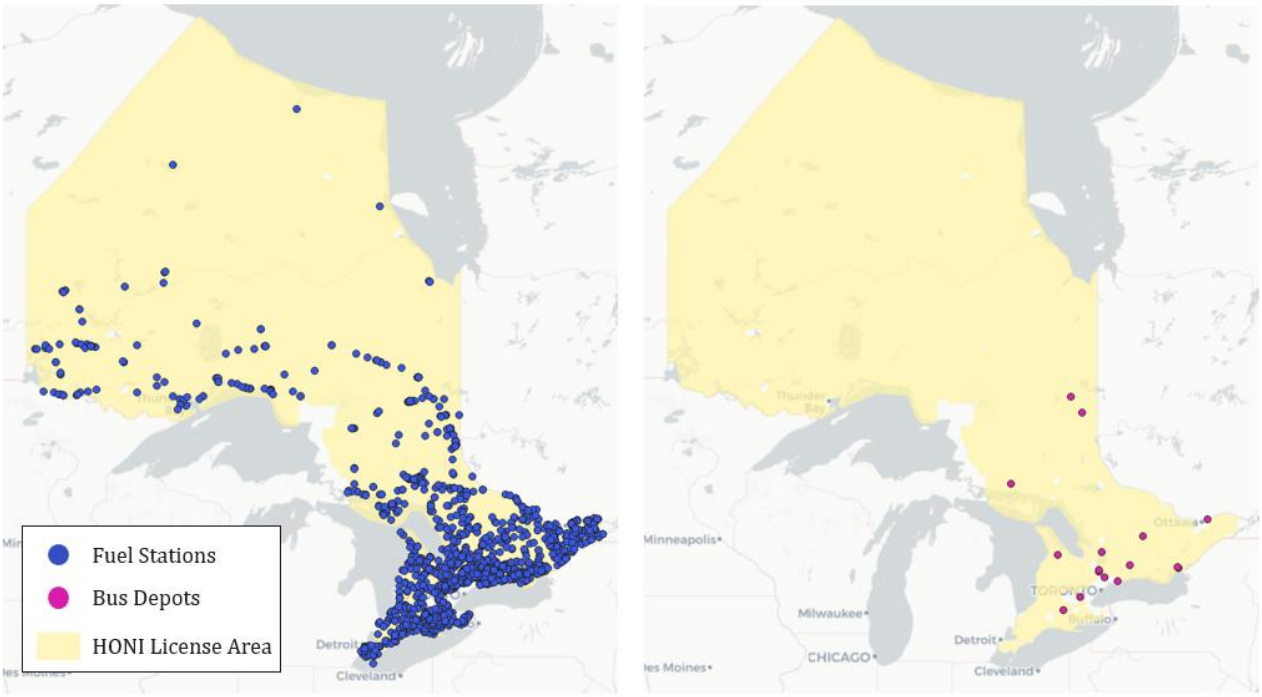


Figure 28: Geographic distributions of fuel stations (left) and bus depots (right).

5.5 ELECTRICITY GENERATION AND STORAGE

A range of generation and storage technologies were assessed in the modelling, including behind-the-meter (BtM) solar and batteries, as well as front-of-the-meter (FtM) generation and storage. The Peak Load modelling approach included BtM generation and storage, as this is seen by all network assets as an effective reduction in the peak load and therefore as a reduction in power flow through the assets.

FtM generation was not explicitly modelled as part of the peak load calculation because it is complicated to precisely predict the impact of large-scale variable renewable generation on peak load. Large capacity of wind might not contribute to peak reduction if the peak happens on a windless day for example.

To model the expected impact of FtM large-scale generation on peak load, peak capacity factors are typically used. These represent how much of the total capacity of a type of generation asset is actually used at peak load time and therefore by how much it can reduce peak load demand. For example, solar generation could have a peak capacity factor of 0 in winter, if the peak occurs after sunset.

The key limitation with these factors is they can only be calculated empirically for previous years, and are therefore not suitable for long term scenario analysis. This is especially true as the total capacity of specific generation types like wind and solar are expected to grow significantly compared to the generation capacity today. Using today's load factors would likely lead to an overestimation of their contribution to mitigating the peak load.

Additionally, any shift in peak time would also mean previously calculated peak capacity factors are unsuitable, for example if the network peak occurs 2 hours later in 2050 compared to 2025 in summer, and therefore the solar contribution to mitigate the later peak is much lower than it would be in 2025.

5.5.1 BEHIND-THE-METER GENERATION AND STORAGE

Rooftop solar and battery storage systems were considered for BtM systems. Feed-in-tariff data on small solar installations was used to baseline the capacity of rooftop solar across Hydro One customers.

Rooftop solar uptake trajectories were aligned to the scenarios in the Canadian Renewable Energy Agency (CanREA) study, *BtM Solar: Canadian Market Outlook* [22]. This study projected that between 1-in-12 and 1-in-3 Canadian homes could install rooftop solar by 2050. Baseline data on rooftop solar installations was found using the IESOs Active Generation Contract List [23]; there are an estimated 15,000 residential and 1,000 non-residential rooftop solar installations as of 2024.

BtM batteries are assumed to be exclusively installed in homes with a solar array. Uptake is modelled as an attachment rate to installed rooftop solar. Data on battery installations in Ontario is not publicly available, so the closest US state to Ontario with data availability (Minnesota) was used as a proxy to estimate attachment rates. An estimated 4% of rooftop solar systems in Ontario are paired with a battery, based on

a Berkley Labs review of battery storage in the USA [24]. In the scenario modelling attachment rate is assumed to increase linearly to 10%, 50%, and 90% for the Business as Usual, System Transition, and Net Zero 2050 scenarios respectively. Capacity projections for behind-the-meter solar and storage are shown in Figure 29.

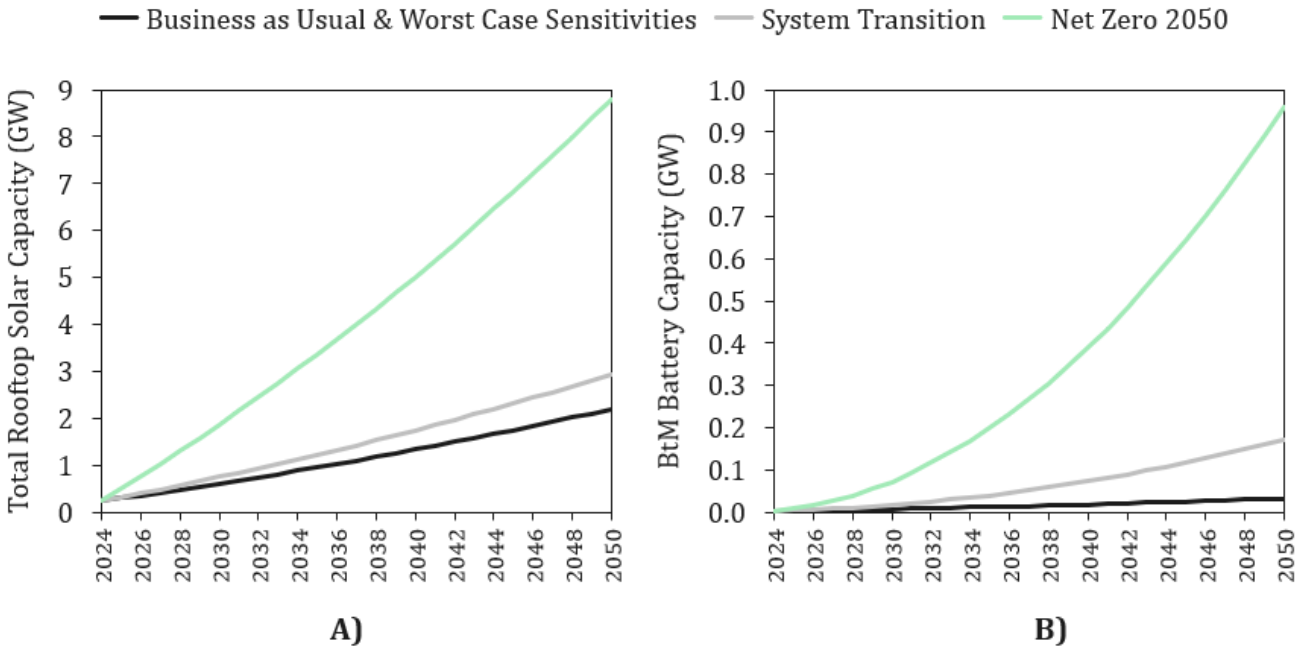


Figure 29: (A) Rooftop solar uptake (GW) for residential and non-residential properties and (B) behind-the-meter battery uptake (GW).

5.6 FLEXIBILITY

5.6.1 DEMAND SIDE FLEXIBILITY

Demand-side flexibility (DSF) refers to the ability of energy consumers to adjust their electricity consumption in response to price signals or other incentives. DSF can include shifting load to off-peak periods or shedding load by temporarily reducing consumption during peak times. Distribution network operators can procure flexibility from large industrial and commercial customers, and increasingly from households and smaller businesses as enabling technologies become more widespread.

Efficiency Canada estimates that the IESO currently has the ability to reduce network peak load by 4% [25] through DSF. Some US utilities have demonstrated significantly greater potential, procuring flexible capacity capable of reducing peak demand by up to 20%. Across the three scenarios in this study, it is assumed that DSF contributes a 10% reduction in peak load by 2050. In the Worst-Case sensitivities, DSF deployment is limited, and peak-load reduction is fixed at 4% (consistent with IESO's estimated current capacity to reduce peak demand), reflecting a lower level of consumer participation and technological adoption.

6. LOAD MODELLING

Following the development of the electrification pathways, the resulting datasets were incorporated into a bespoke load model to model load growth and electricity generation across the Hydro One distribution network to 2050. The model produces annual consumption and half-hourly load projections across 1,088 transmission and distribution stations, as well as for the network as a whole, providing a comprehensive view of potential future changes to network demand.

In addition to peak-load projections at the asset level, the model generates a breakdown of peak demand and energy consumption by end-use technology. This supports a detailed understanding of the drivers of load growth and enables end-users to identify, and prioritise network investment needs.

6.1 METHODOLOGY OVERVIEW

The load modelling process is described in Figure 30, and uses the uptake trajectories for electrified technologies disaggregated at station-level described in the previous section. Technology counts here refers to the projected number of each technology (or capacity figures in the case of generation and storage) and how they are distributed across the network. The development of technology count trends is described in Section 5.

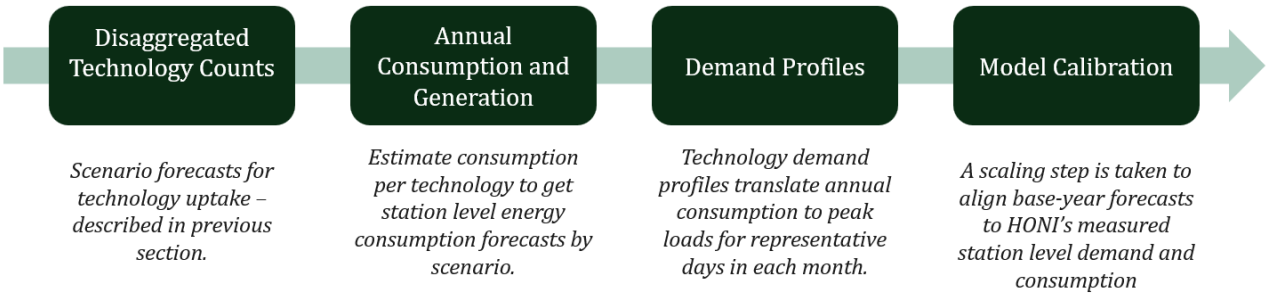


Figure 30: Key steps in estimating future power demand across Hydro One network assets

6.2 CONSUMPTION CALCULATION AND CALIBRATION

First, the total consumption of all these technologies is calculated at station level, and the commercial demand consumption calibrated to the observed consumption at each station. The whole process is described in detail in Figure 31. The annual energy demand for all technologies and building types are identified using NRCAN and other sources specific to Ontario. Once the consumption for all types of technologies is calculated for the baseline year, the annual energy efficiency and technology efficiency changes are factored in to calculate annual consumption from all technologies to 2050 at station level. In order to calibrate the calculated consumption in the baseline year to the observed consumption at station level, we adjust the I&C customer consumption. The reason for using the I&C demand for this calibration is that the I&C stock is very diverse and modeled using archetypes, hence we expect it is likely to be

a less accurate reflection of actual demand than the residential component, where archetypes tend to describe actual consumption relatively closely. Finally, the annual consumption from all technologies is calculated at station level.

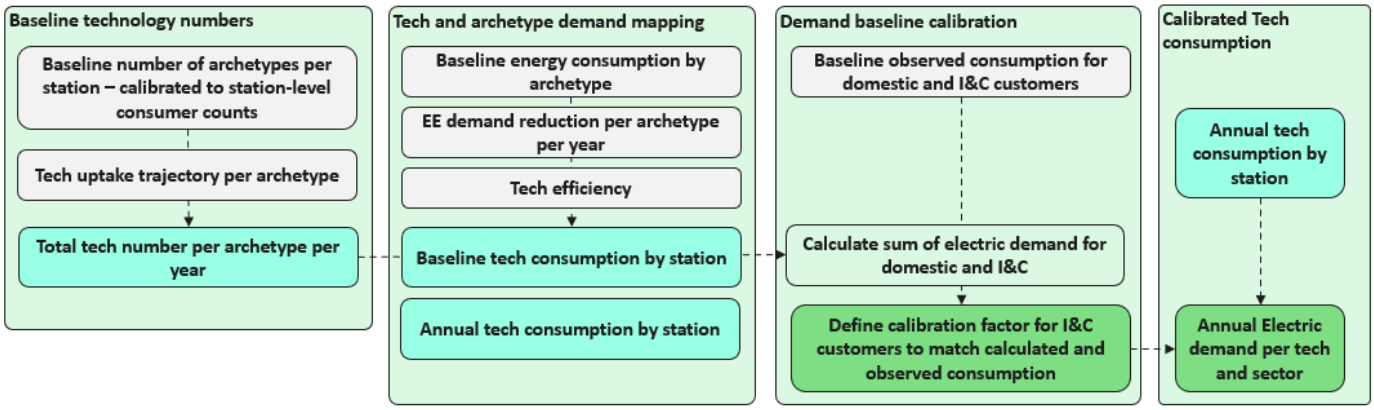


Figure 31: Modelling data flow for consumption calculation and calibration

Estimated annual thermal and core household consumption is shown in Table 13 as an example. Note that in the case of thermal demand, a coefficient of performance is applied to the thermal demand if the home installs a heat-pump.

Table 13: Example of annual consumption estimates for residential building core and thermal demand.

Demand Source	**Archetype**	Consumption (KWh/Year)	**Source(s)**
Core Demand	Apartment	3, 300	NRCAN [2]
Core Demand	Detached/semi-detached	6, 000	NRCAN [2]
Core Demand	New Build	2, 700	NRCAN [2]
Thermal Demand	Apartment	10, 500	NRCAN [2]
Thermal Demand	Detached/semi-detached	22, 400	NRCAN [2]
Thermal Demand	New Build	13,700	City of Ottawa [26]

6.3 PEAK DEMAND CALCULATION AND CALIBRATION

The next step is the calculation and assignment of half hourly normalised consumption demand profiles for each technology. This enables the calculation of half hourly demand for all stations, and from this the peak demand in summer (May to October) and winter (November to April) can be identified. The detailed modelling process is described in Figure 32.

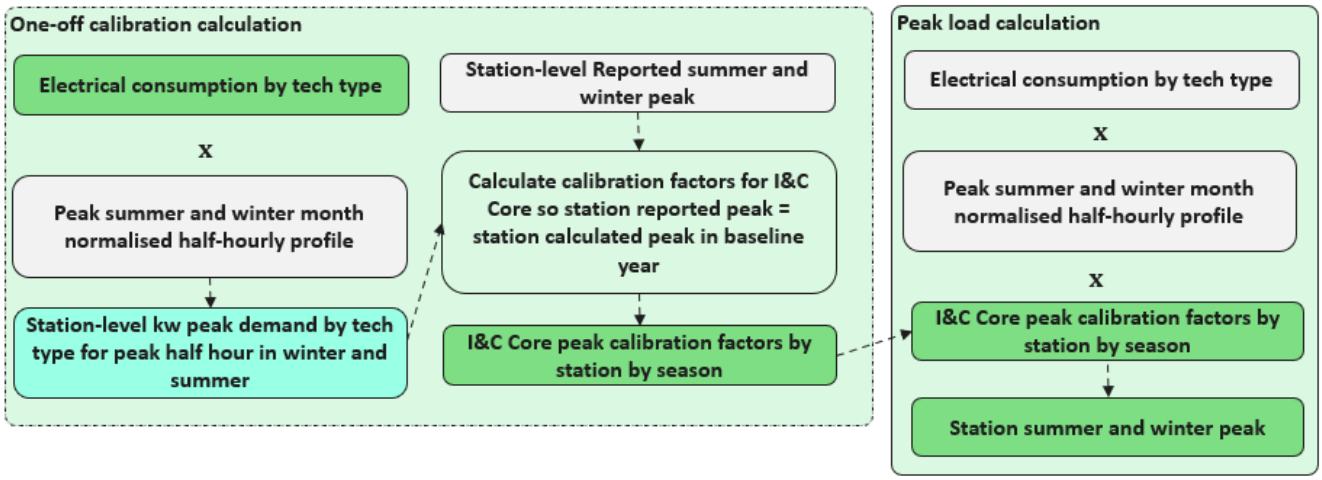


Figure 32: Modelling data flow for peak demand calculation and calibration

The annual consumption for each technology and archetype is multiplied by a normalised annual consumption profile, to translate technology counts to half-hourly demand. Figure 33 shows an example of the resulting profile for a detached home core demand. Similar profiles are obtained for all archetypes and technologies, multiplied by the number of technologies and all profiles are summed together.

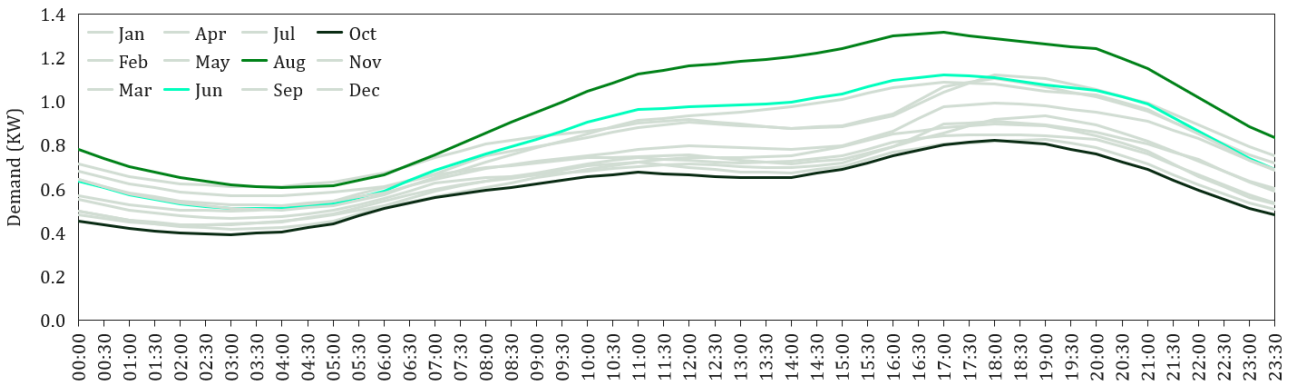


Figure 33: Demand profile for the residential core demand of a detached/semi-detached home in Ontario

For the peak calculation, I&C calculated peak consumption is also calibrated to the Hydro One asset-level observed peak consumption. This is again because the I&C sector is very heterogeneous and the contribution of this sector to the peak demand is complicated to estimate without detailed specific consumer data processing. Using the calibration approach, generic archetypes can be used, and their peak consumption scaled up and down to match the observed data in the baseline year. The resulting

scaling factor was then applied uniformly across all forecast years to maintain consistency in the projected load trajectory.

6.4 PEAK DEMAND AGGREGATION AND NETWORK UTILISATION

6.4.1 PEAK DEMAND AGGREGATION

For the purposes of this analysis, ERM made the modelling simplification that the network-wide peak is equal to the sum of all individual station peaks. This avoids having to report two peaks per station per season, one corresponding to the station peak, and one corresponding to the network-wide peak. The impact on the outcome network peak demand calculated is expected to be negligible because most station peaks happen at similar times.

Additionally to the bottom-up load calculations, Hydro One data on large-demand customer connection requests was used to estimate near-term growth in I&C connections. It is assumed that the current pipeline of connection requests, totalling 1,051 MW of peak demand, will be fulfilled over the next eight years, and this additional peak load growth has been added to the calculated bottom-up load growth.

The peak demand was also aggregated across the following 5 regions of Ontario, following the same approach as described for the network-wide peak calculation:

- North West
- North East
- Central
- East
- South West

6.4.2 NETWORK UTILISATION RATE CALCULATION

The network utilisation rate shows whether the peak load is projected to increase faster or slower than the energy consumption, and as a result, whether the network infrastructure is being used more efficiently. More efficient use of the network reduces the amount of additional capacity that needs to be built as demand grows, delivering cost benefits to customers..

The detailed step-by-step modelling approach is described below:

- Calculate the annual energy consumption from all existing electrified technologies and new electrified technologies that will connect to the system
- We compare the growth in Energy use and Winter Peak Load as the system becomes winter peaking post 2030s to infer utilisation rate. Here the annual calculated peak load is used as denominator, and not the capacity that would be available through existing headroom or reinforcement. Using the latter would require modelling reinforcement of the network, which is beyond the scope of this study.

- We remove the I&C peak growth impact on the peak load growth because we do not have an associated consumption for I&C pipeline growth. This avoids the utilisation rate coming down in the earlier years as a result
- The network utilisation rate is calculated as: Consumption / Winter Peak / 8760. We divide by 8760 (number of hours per year) to make the utilisation rate easier to understand.
    - As an example, a station with 1,000 MWh of consumption and 1MW of peak demand will have a utilisation of: 1,000 / 1 / 8760 = 0.11. If the consumption was 8,760 MWh, the utilisation would be: 8760 / 1 / 8760 = 1. This is not a realistic example but is meant to clarify what the network utilisation rate represents.
- We finally calculate the % change in network utilisation rate annually as: (in-year utilisation - baseline year utilisation)/ baseline year utilisation
        - We then report the change rather than the absolute utilisation rate annually
        - As an example, if the baseline utilisation is 40% and this grows to 60%, the reported growth will be (60-40)/40 = 50%

7. RESULTS

7.1 NETWORK PEAK LOAD

Using the Hydro One Load Model developed by ERM, and the modelled low-carbon technology trends, an estimated peak load by season across stations was calculated. Station level loads were summed to find a network level peak load, shown in Figure 34. The seasons were defined as follows:

- Winter: November to April,
- Summer: May to October

Key Findings

Across all scenarios, peak demand is expected to rise over the coming decades, driven primarily by the electrification of heat and transport, as well as by a near-term estimate pipeline of large I&C demand connections. Hydro One is expected to switch from a summer network peak to a winter peak within the next decade as heating electrifies.

The Business as Usual scenario presents the slowest load growth, reflecting limited uptake of electric technologies. In contrast, both System Transition and Net Zero 2050 show substantially higher peaks, consistent with widespread adoption of heat pumps and electric vehicles.

Notably, the *Net Zero 2050 – Worst-Case* and *System Transition – Worst-Case* sensitivities reveal the significance of energy efficiency, behind-the-meter solar and storage, and demand-side flexibility to mitigate the increase in peak load. These sensitivities assume minimal improvements to building fabric efficiency, lower uptake of rooftop solar and battery storage, and no further procurement of demand-side flexibility (peak shifting), resulting in considerably higher peak loads despite identical technology uptake assumptions to the core scenario equivalents.

The Net Zero 2050 and System Transition central scenarios converge to similar peaks by 2050. This occurs because the higher electrification rates in Net Zero 2050 are broadly offset by stronger improvements in energy efficiency and higher penetration of behind-the-meter solar and storage. As a result, despite the more ambitious electrification pathway, the network winter peak does not exceed that of System Transition.

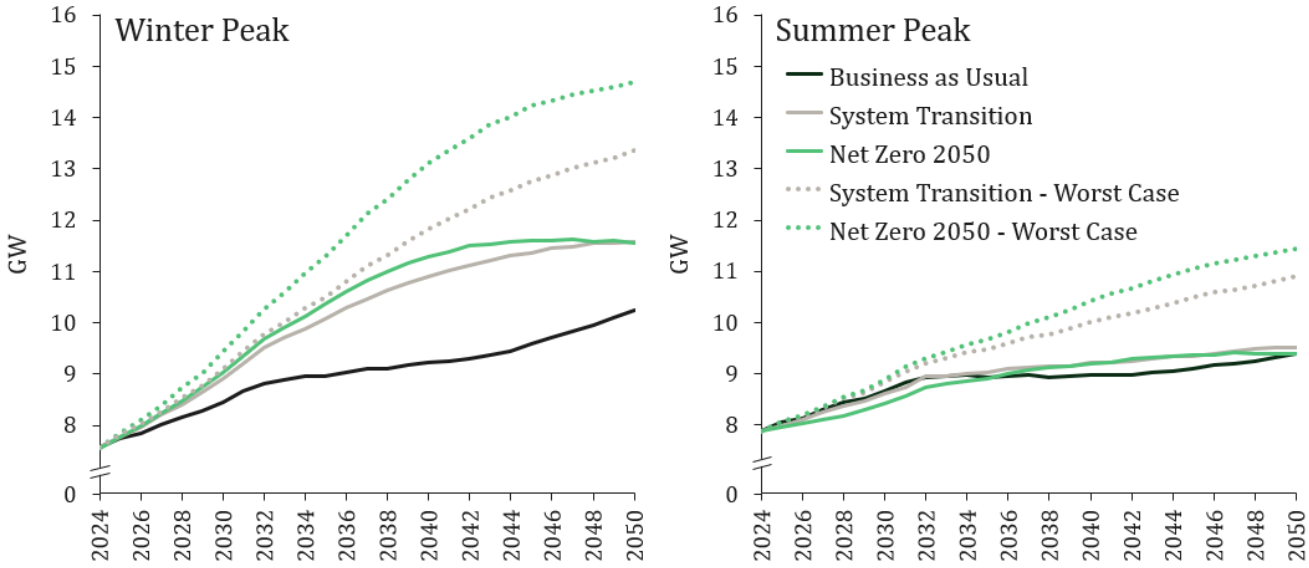


Figure 34: Peak load by scenario and sensitivity for winter (left) and summer (right), 2024 – 2050

7.2 CONTRIBUTION TO PEAK LOAD BY TECHNOLOGY

In Figure 35, network peak load is broken down by end-use category. Heating demand is separated into heat-pump systems (including ASHP, GSHP, and hybrid configurations) and traditional electric resistive heating, which remains prevalent across the Hydro One customer base. The 'EV' category covers battery electric and plug-in hybrid vehicles across all chassis types. 'Core' represents all other end-uses, including air-conditioning, appliances, lighting, and industrial and commercial loads.

The visible heat pump contribution to summer peak is not due to air-conditioning (which is included within the "Core" segment), but is reflective of the fact that some stations experience their summer peak in May, when there is still a significant heating demand.

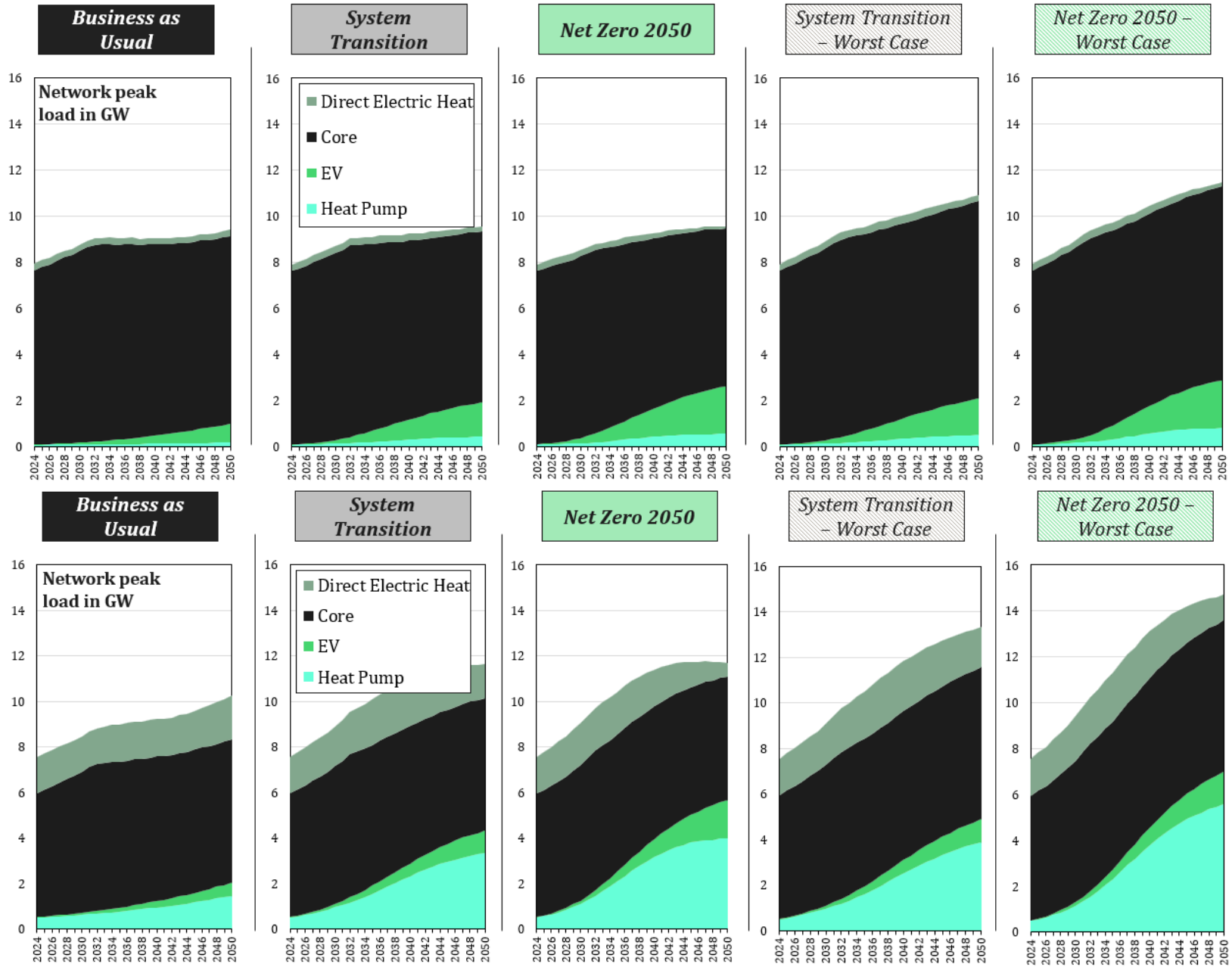


Figure 35: Contribution to network peak load by technology group for **summer (above)** and **winter (below)**. 'Core' refers to all non-heating or transport energy consumption (i.e. Air-Conditioning, appliances, and industrial and commercial end-uses).

Key Findings

Considerable increases in energy consumption from electrification of heat and transport result in increased peak load from these end-uses. The increase in winter peak-load is driven by heat-pump uptake across scenarios. While the electricity consumption from EVs does increase significantly, this end-use is found to have a lesser impact on peak load. This is due to the time-of-peak: the network peak occurs in the early evening, which has greater coincidence with the heating demand profile than the EV charging profiles. Hydro One customers tend to ramp up the charging of their vehicles from 4pm, with the main charging time being during the 7pm-2am time period (Figure 36), and this behaviour is assumed to continue.

EVs are also expected to consume slightly more electricity in winter than in summer due to additional heating requirements. However, EVs have a larger impact on the summer peak. This is because uptake of rooftop solar and behind-the-meter storage reduces the early-evening (5pm) summer peak slightly (but less so the winter peak), and there is minimal evening load from heating demand in summer months. The result is that the network summer peak shifts to later in the evening, increasing the EV contribution to summer peak-load (relative to winter months).

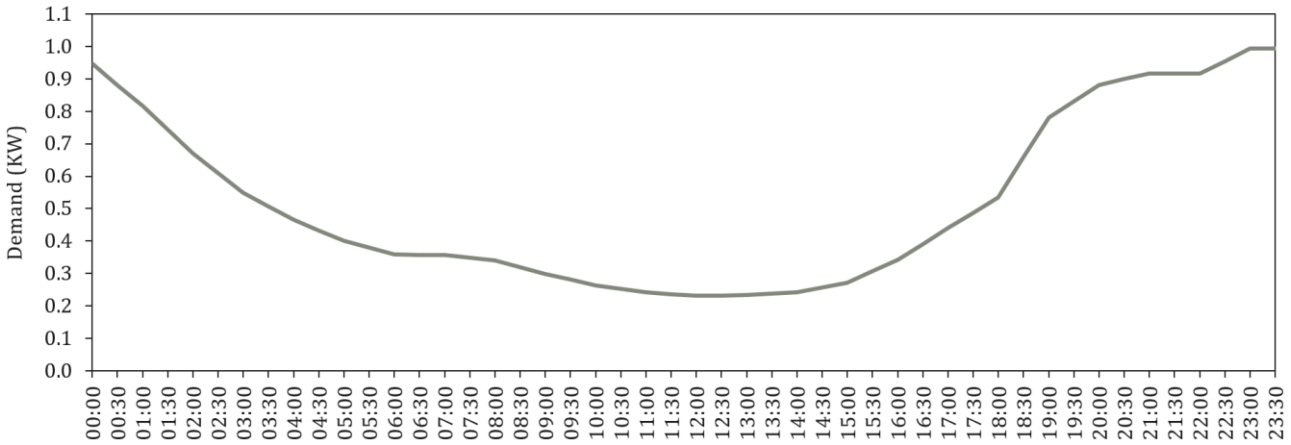


Figure 36: Average Hydro One customer's BEV car charging profile for a January day.

7.3 TIME OF PEAK SHIFT

The Peak Load modelling approach enables the calculation of the actual peak half hour for each station of the network. As a result, ERM was able to identify a significant shift in the summer peak load hour between 2025 and 2050, as visible in Figure 37. In summer, the time of peak is expected to shift to later in the evening due to rooftop solar contribution and EV demand and the minimal daytime/evening heating demand.

Uptake of EVs adds more load to evening/night (peaking at 22:00), while the winter heating load peaks around 17:30. The low heating load in summer shifts the peak later in the evening, while winter peak hovers around 18:00. In addition to this, uptake of solar PV decreases load in summer in the early evening, further pushing the summer time of peak into the evening. As a result of the summer time of peak shifting towards later in the evening, the absolute contribution to network peak from

EVs is higher in summer than in the winter, despite EVs having a greater demand in winter than in summer.

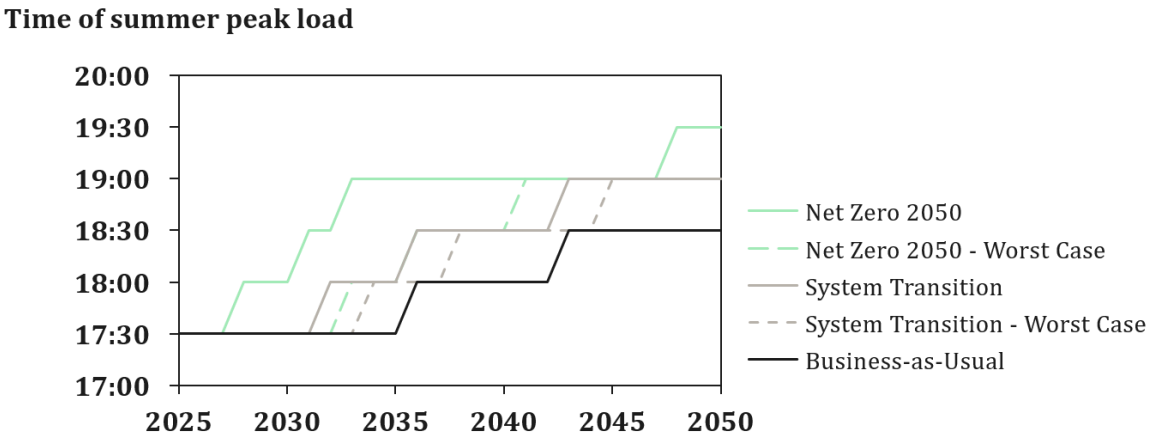


Figure 37: Shift in the time of summer peak load peak, from 2025 to 2050

7.4 COST-EFFECTIVE SOLUTIONS

Reinforcement of network infrastructure can be costly. 'Non-wires' solutions can offer cost-effective alternatives to grid reinforcement, either delaying or reducing network build-out. The most relevant non-wires solutions were considered in the report:

Non-wires Solution	Study Definition
Demand-Side Flexibility (DSF)	Incentivising energy consumers to reduce or shift demand during periods of peak demand. Behind the meter generation is considered DSF but not modelled explicitly in this study.
Energy Efficiency	Reducing electricity consumption by improving the performance of appliances, equipment, and building fabric.
Distributed Energy Resources (DERs)	Behind-the-meter solar PV and battery storage.

By including 'Worst-case' sensitivities for the Net Zero 2050 and System Transition scenarios, it is possible to estimate the difference in system demands that would be seen for an electrified future with less ambitious deployment of these key non-wires solutions. The worst-case sensitivities see the same uptake of electric technologies as their respective electrification pathways, but the same improvements to energy efficiency and DERs as the Business as Usual (and no increase in DSF).

The sensitivities highlight that future load growth is influenced significantly by the deployment of non-wires solutions (Figure 38). The Net Zero 2050 worst-case sensitivity has a 2050 winter peak load that is 27% greater than the Net Zero 2050 scenario. This is driven primarily by energy-efficiency; in the Net Zero 2050 worst-case sensitivity, 63% of the increase in load is from reduced improvements in core and thermal energy efficiency. A further 31% of the increase in peak load comes from lower demand-side flexibility, and 6% of the increase results from lower uptake of DERs. The low contribution from DER is explained through the peak time shift described above: the time of peak happens on average after sunset, hence even large rollout of DER, which is predominantly solar, contributes little to lowering the peak demand. The contribution from non-wires solutions to the Net Zero 2050 sensitivity is seen in Figure 39.

Improving the efficiency of energy end use (primarily thermal end-uses), and procuring demand-side flexibility, plays a critical role in mitigating the peak-load impacts of electrification.

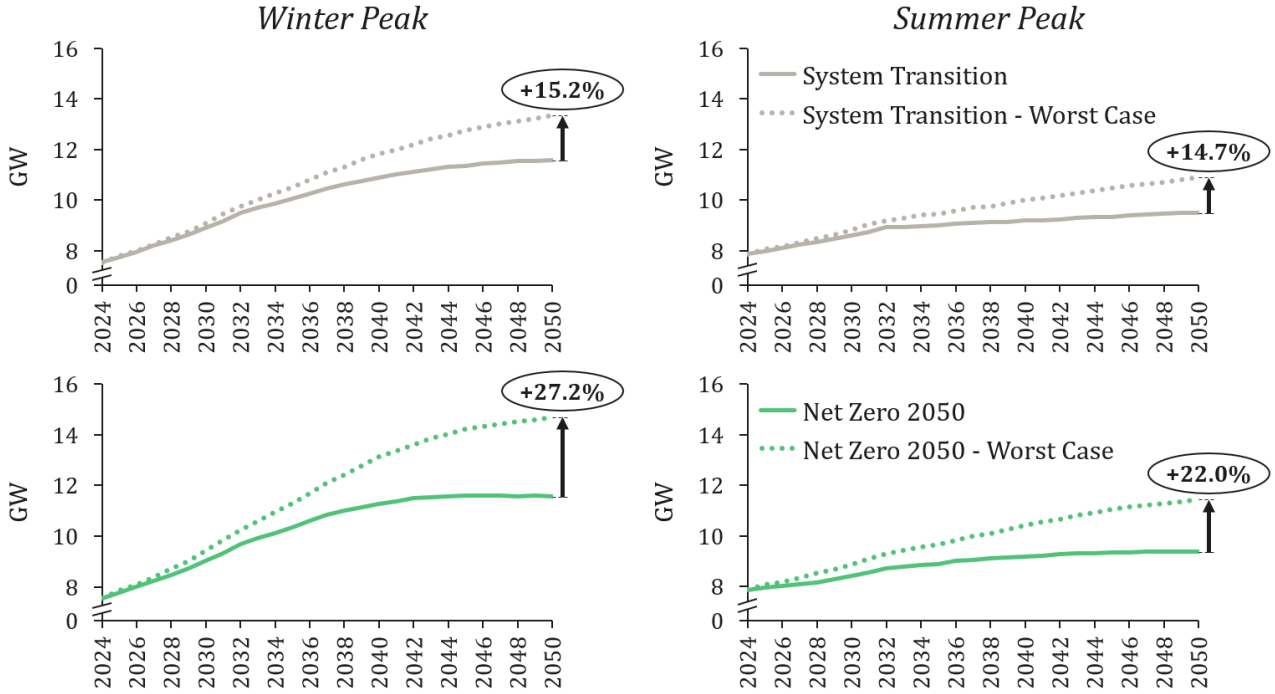


Figure 38: Winter (left) and summer (right) peak load for the System Transition and Net Zero 2050 scenarios, and their worst-case sensitivities.

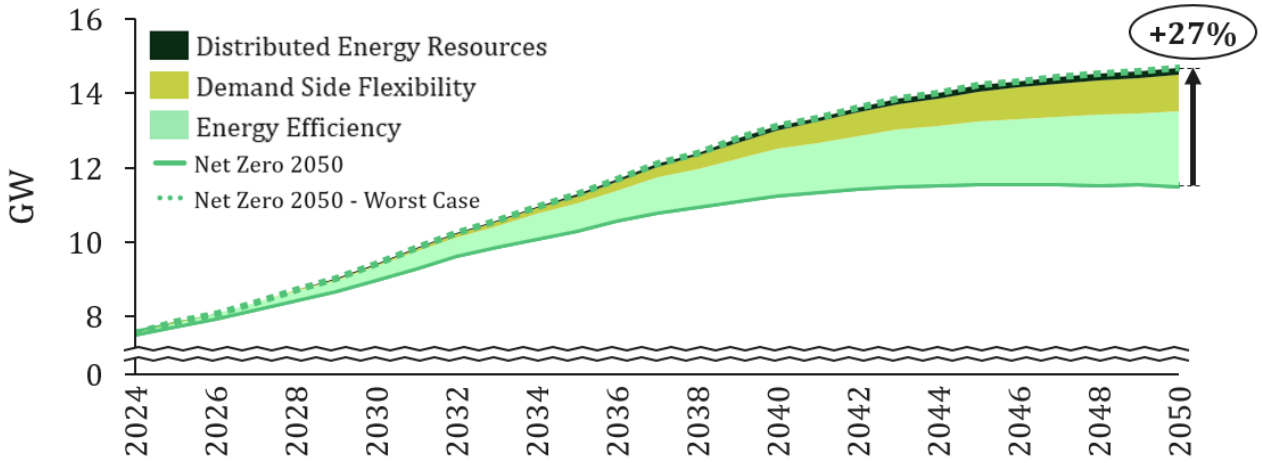


Figure 39: Peak winter load for the Net Zero 2050 scenario and worst-case sensitivity, with driver contributions from Energy Efficiency, Demand Side Flexibility, and Distributed Energy Resources.

7.5 NETWORK UTILISATION RATE

The Network utilisation rate was observed to increase consistently with time across all scenarios and sensitivities. The Net Zero 2050 and System Transition scenarios have a significantly higher utilisation rate increase compared to other scenarios, increasing 25% by 2050. This is due to increased demand from EVs, which largely charge in the evening and overnight during historic periods of low demand, and play a significant role in increasing utilisation rates. The additional demand-side flexibility that is expected in the core scenarios works to shift peak load and increases utilisation of the network. Additionally, increased consumption from rooftop solar results in consumer demand being met without impacting the system peak demand. All these factors increase network utilisation by enabling extra demand to be added to the network without any significant increase in peak load.

The Business as Usual and the worst-case sensitivities are expected to see an increase in network utilisation rate of up to 15% by 2050. Lower uptake of BtM generation, EVs, and a lack of increase in demand side response, result in a reduced increase in network utilisation compared to System Transition and Net Zero 2050. There is still an increase in utilisation rate mainly led by EVs overnight charging, reflecting today's charging approach. Uptake of BtM generation, although significantly less than in the Net Zero 2050 and System Transition scenarios, also contributes to the increase in network utilisation rate.

These results indicate that the electrical demand met by the network increases at a faster rate than the increase in network peak load across all scenarios and worst-case sensitivities. This flattening of the load profile means that network infrastructure is being used more efficiently and should reduce the amount of additional capacity that needs to be built as demand grows, delivering cost benefits to customers. In the Net Zero 2050 and System Transition in particular, the level of electrification and

improvement in infrastructure utilisation could benefit customers by reducing costs by a higher amount than in other scenarios and worst-case sensitivities.

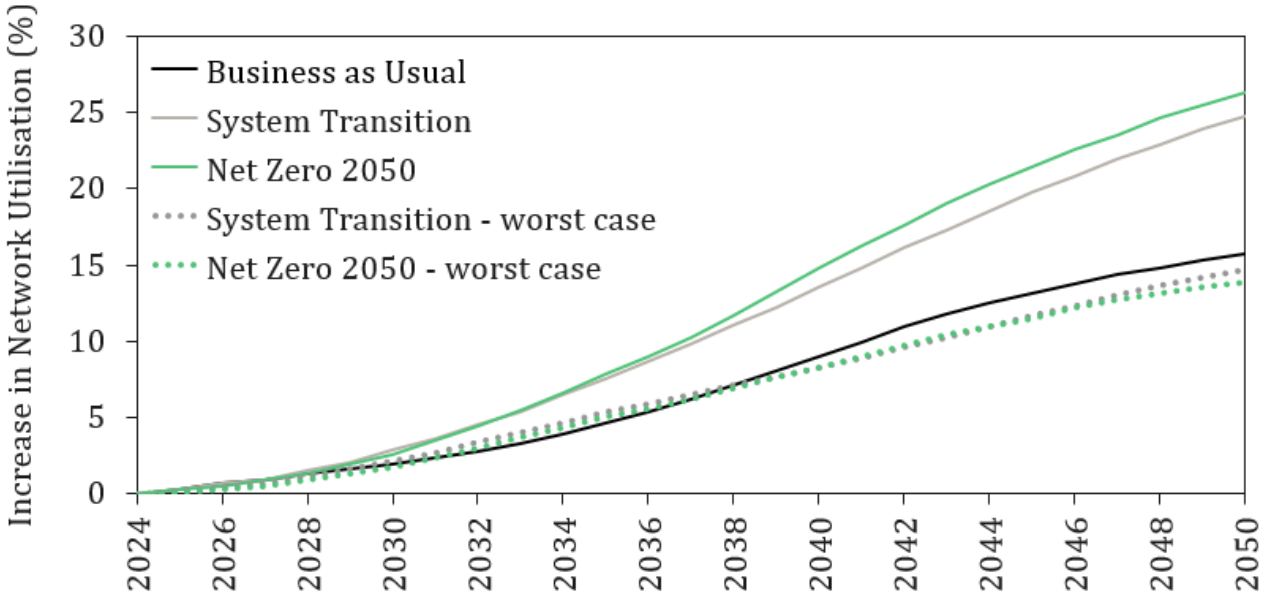


Figure 40: Increase in network utilisation rate for all electrification scenarios and sensitivities.

7.6 REGIONAL AGGREGATION ANALYSIS

Analysis of load growth across geographic regions of Hydro One's service area was performed. Figure 41 shows the South West and East regions are expected to experience the largest increase in peak load due to being the most densely populated. The South West and Central zones are expected to gain the most benefit from DER, EE, and DSF, as indicated by the difference in peak load increase between the NZ and NZ worst-case scenarios. The North West and North East regions are expected to experience little growth in peak load.

Globally, the shape of the peak load growth to 2050 for each region is aligned with the network-wide peak load growth to 2050.

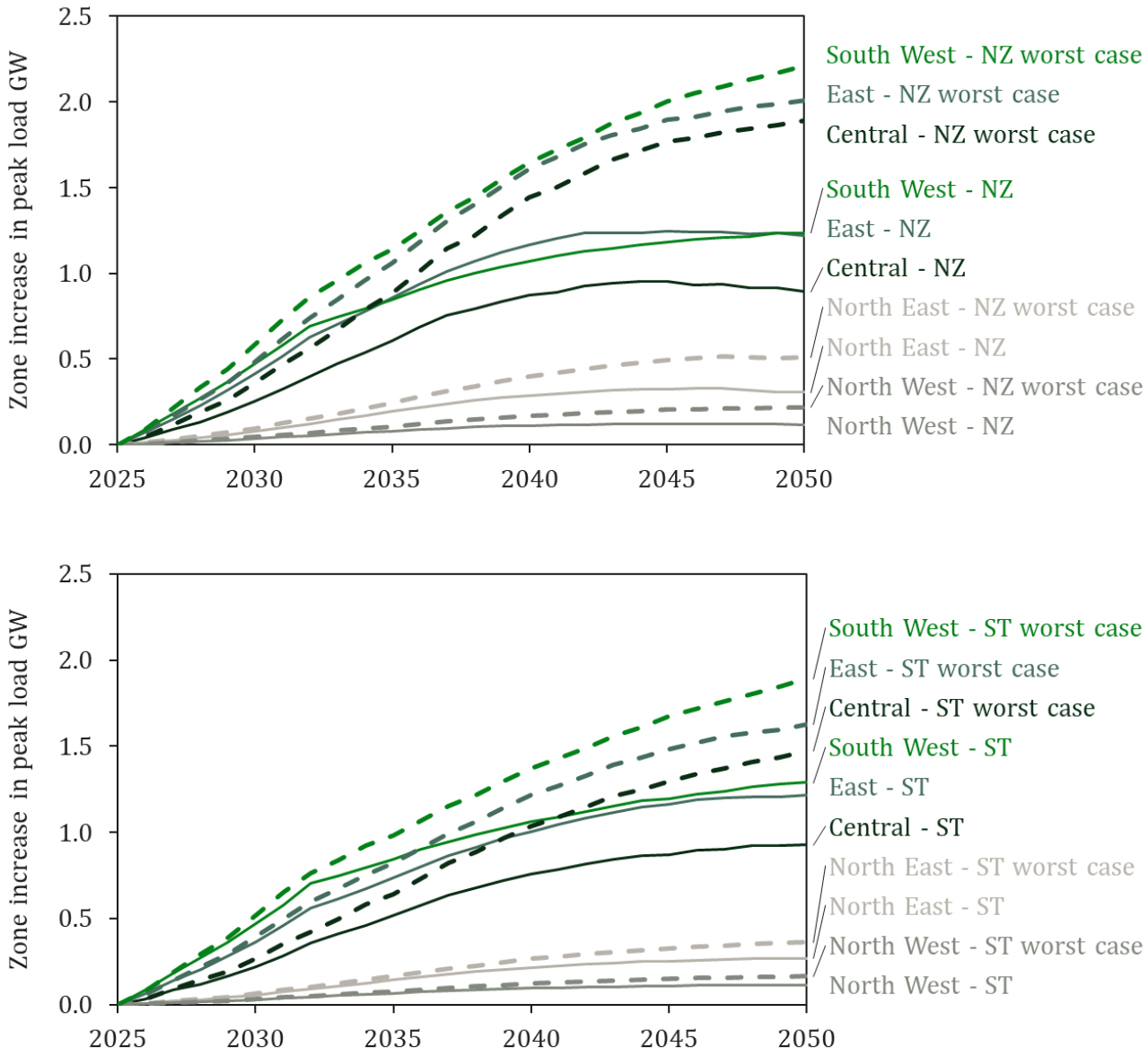


Figure 41: Projected increase in Peak Load for all 5 Zones for the NZ 2050 (top) and System Transition (bottom) scenarios and sensitivities

8. CONCLUSIONS

This study was commissioned to provide Hydro One Networks Inc. (Hydro One) with an independent, scenario-based assessment of how electrification could affect electricity demand and peak load across its distribution network between 2030 and 2050. The primary aim was to understand the scale, timing, and drivers of future peak load growth, with a particular focus on how different electrification pathways could impact the network peak load. The study also sought to provide directional insight into the role that non-wires solutions can play in mitigating peak demand, without undertaking formal cost or net present value analysis.

A structured scenario framework was used to capture uncertainty in long-term electrification possibilities. Three core scenarios were developed, ranging from a Business as Usual pathway through to a highly ambitious Net Zero 2050 pathway, alongside worst-case sensitivities that tested the impact of weaker deployment of energy efficiency, distributed energy resources, and demand-side flexibility. These scenarios were not assigned probabilities; instead, each represents a plausible future used to model the network under different combinations of policy ambition, consumer behaviour, and technology uptake.

Electrification drivers were modelled bottom-up, including population and connection growth, electrification of heat, electrification of transport, energy efficiency improvements, behind-the-meter generation and storage, and demand-side flexibility. These drivers were spatially disaggregated to individual Hydro One stations and incorporated into a bespoke load model that produces annual energy consumption and half-hourly demand profiles to 2050. Industrial and commercial demand was calibrated to observed station-level data, and a near-term pipeline of large I&C customer requests was incorporated to capture near-term peak growth.

Across all scenarios, the results show a substantial increase in network peak load over the coming decades, driven primarily by the electrification of space and water heating and, to a lesser extent, electric vehicle uptake and new large I&C HV customer connections. The total network peak load is modelled to increase from 8 GW today to up to 15GW by 2050. A key finding is that the Hydro One network is expected to transition from a summer-peaking to a winter-peaking system within the next decade, based on the assumption that heating electrifies. Winter evening peaks become the dominant system constraint, while summer peaks shift later into the evening as rooftop solar reduces early evening demand and electric vehicle charging increases evening and overnight consumption.

Despite higher levels of electrification, the Net Zero 2050 and System Transition scenarios result in similar winter peak demand by 2050. This outcome reflects the offsetting effect of stronger improvements in building fabric efficiency, higher appliance efficiency and greater deployment of behind-the-meter solar and storage in the Net Zero 2050 scenario. In contrast, the worst-case sensitivities demonstrate that, if these non-wires solutions are not delivered, including demand side flexibility, peak

demand could be significantly higher even when electrification uptake remains unchanged. For example, the Net Zero 2050 worst-case winter peak in 2050 is about 27% higher than the Net Zero 2050 central case. Of that 27% gap, approximately 63% is attributable to weaker energy-efficiency progress, around 31% to lower demand-side flexibility, and roughly 6% to reduced behind-the-meter solar and storage uptake.

The analysis highlights that improvements to building thermal performance, appliance energy efficiency and demand-side flexibility could be effective non-wires levers for mitigating the increase in peak load. Behind-the-meter solar and storage can provide additional benefits, particularly for reducing energy consumption and mitigating summer peaks, but their ability to reduce winter evening peaks is more limited. Improvements in network utilisation rate of 15-25% are observed across the different scenarios, indicating that electricity consumption grows faster than peak demand, allowing network assets to be used more intensively over time.

The study establishes an evidenced view on how electrification could reshape future network demand and identifies the conditions under which ambitious decarbonisation pathways can be achieved without proportionally higher peak loads. The results underline the importance of integrating energy efficiency programmes, demand-side flexibility, and distributed energy resources into long-term network operations. These insights can support Hydro One in targeting cost-effective non-wires solutions, while detailed cost-effectiveness assessments are undertaken separately using OEB’s established regulatory frameworks on a project-by-project basis.

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January 23, 2026

Hydro One Networks In.
483 Bay Street
7th floor, South Tower
Toronto, ON M5G 2P5

Attention: John McCarthy, *Regulatory Advisor*

Dear John:

RE: DISTRIBUTION ELECTRIFICATION SCENARIOS STAKEHOLDER CONSULTATION SESSION

Thank you for the opportunity to provide an independent facilitation service to Hydo One Networks Inc. This letter provides a brief summary of the session.

The intervenor consultation took place virtually at 900hrs ET on November 25, 2025. It concluded at approximately 1100hrs ET. Of the ten registered intervenors organization, nine participated and one sent last minute regrets. The Ontario Energy Board, Hydro One staff, Torys LLP and Hydro One's consultant ERM.

The consultant provided a presentation of their current analysis and findings for the electrification scenarios they are undertaking for Hydro One. Participants were provided with the opportunity to ask questions and provide comments on the study.

Participants commented that the study was a good start. The discussion revolved around the following topic areas:

1. Impact of electric vehicles;
2. Distributed energy resources;
3. Large incremental loads;
4. Local impact of electrification;
5. Distribution system operator;
6. Cost analysis; and
7. Non-wires alternatives.

The consultant was asked to consider the input for their analysis and final report.

It was a pleasure to provide this service. Please reach out should you have any further questions.

Sincerely,

Andrew Pride, P.Eng.

Hydro One Networks Inc. (HONI): Distribution Electrification Scenarios Stakeholder Consultation Session - Intervenor Organizations Attendance

1. Quinte Manufacturers Association
2. School Energy Coalition
3. Environmental Defence
4. Canadian Manufacturers and Exporters
5. Energy Probe
6. Pollution Probe
7. Association of Major Power Consumers in Ontario
8. Society of United Professionals
9. Ontario Federation of Agriculture
10. *(regrets) Consumers Council of Canada*

SECTION 3.4 – DSP – CONNECTING DER RESOURCES

3.4.1 OVERVIEW

This exhibit 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 OEB's Chapter 5 Filing Requirements.

In the context of this schedule, DERs are electricity sources that connect to the distribution system and supply electricity to serve local areas, including energy storage systems. Hydro One classifies DER into three categories for planning purposes:

- Mid/Large DER (> 500kW)
- Small DER (>12 kW, ≤500kW)
- Micro-embedded generation (≤12kW).

At the end of 2025, Hydro One had connected over 20,000 DERs for a total of 2,837MW[1] to its distribution system. Figure 1 provides a breakdown of the total DERs connected to Hydro One distribution system by project size.

[1] In the 2023-2027 rate application (EB-2021-0110) Hydro One reported 3,174MW of installed capacity. The reported MW total included DERs connected to other LDC systems that are not directly connected to Hydro One's distribution system. These DERs have been excluded from the current count and as a result, the reported DER capacity is lower than previously reported.

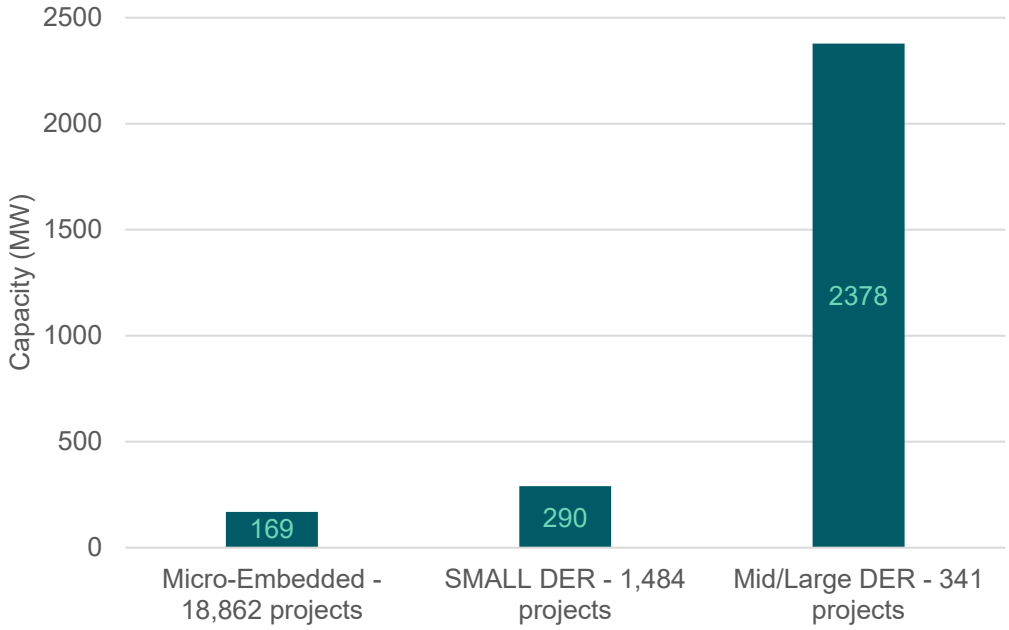


Figure 1: Total Connected Capacity by DER Project Size

The DERs connected to Hydro One's distribution system primarily consist of solar, wind and hydroelectric installations, ranging in size from a few kW to several MW. Figure 2 illustrates the connected DER capacity by fuel type. In recent years, Hydro One has observed increased interest in the connection of Battery Energy Storage Systems (BESS). A BESS operates as a load when charging from the grid, and as a generator when discharging into the system.

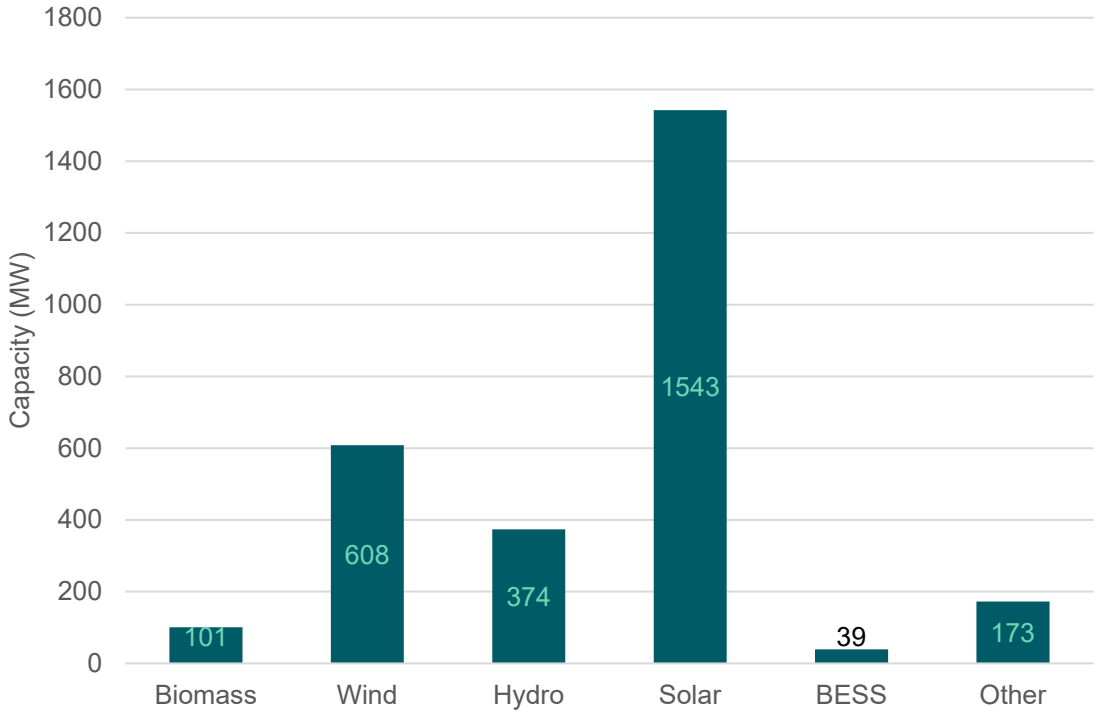


Figure 2: Total Connected Capacity of DER by Fuel Type

Hydro One continues to process and connect new DER applications in accordance with the Distribution System Code (DSC) and the Distributed Energy Resources Connection Procedures (DERCP). Additionally, the OEB expects that distributors "prepare for DER impacts on their systems, including integrating these resources cost-effectively, while maintaining reliable service for their customers."[2] To meet these expectations and ensure that the limitations of the distribution system do not pose an undue barrier to customers exercising their choice to adopt DER, Hydro One is implementing various initiatives as described in section 3.4.6 below.

As required by section 5.3.4 of the OEB's Filing Requirements, this evidence (i) provides a list of restricted feeders by name, the feeder designation, the reason for the restriction, and number of connected customers, and (ii) explains Hydro One's plans to improve its distribution system's ability to connect DER. This information can be found in Table 4.

[2] Framework for Energy Innovation: Setting a Path Forward for DER Integration, OEB, January 2023, p. 3.

Throughout this evidence, Hydro One also provides the various data points required in Appendix 5 of Chapter 5 of the Filing Requirements.

3.4.2 RENEWABLE APPLICATIONS

Following the conclusion of the Feed-in Tariff (FIT) program in 2018, DER activity within Hydro One's service territory shifted toward behind-the-meter (BTM) load displacement generation. This activity has primarily been driven by participation in the IESO's Industrial Conservation Initiative (ICI) program and the Ontario Net Metering program, established under Ontario Regulation 541/05 (O. Reg. 541/05), which is limited to renewable generation. In parallel, Hydro One continues to observe ongoing activity associated with the refurbishment and upgrading of legacy non-utility generators (NUGs), particularly hydroelectric facilities.

Looking ahead, these sources of DER activity are expected to persist, with further growth anticipated as a result of IESO procurement initiatives under the Resource Adequacy Framework. The first phase of the Long-Term Procurement (LT1) process has been completed, with contracted projects expected to come into service between 2026 and 2028. Additional DER connections are anticipated under the second phase (LT2), which is intended to address system needs beyond 2030. These procurements are expected to be energy-source agnostic and will likely result in a mix of renewable and non-renewable DER connections.

The IESO's ICI program continues to provide incentives for large electricity consumers to reduce Global Adjustment costs by curtailing grid consumption during peak demand periods. DER facilities developed under this program are predominantly non-renewable and typically range in size from approximately 500kW to 20MW, depending on the host facility's load. Since 2018, DER applications received by Hydro One under this framework have primarily consisted of combined heat and power (CHP)/co-generation, natural gas, diesel generation, and battery energy storage systems (BESS). Connection costs for these non-renewable DER projects are fully recoverable from the proponent. At present, Hydro One is receiving a relatively limited number of new applications under the ICI program.

The Net Metering program remains an active and consistent driver of renewable DER connections. Pursuant to O. Reg. 541/05, it enables residential, commercial, and industrial customers to reduce electricity costs by offsetting consumption through renewable generation.

Most recently, in 2025, as part of the Save on Energy initiative, the Province of Ontario introduced incentives for residential customers installing solar photovoltaic (PV) and/or battery energy storage systems to support behind-the-meter load displacement. Incentives are also available to commercial, industrial, and institutional customers installing behind-the-meter solar PV systems for the same purpose. This program applies to two categories of eligible projects: micro-embedded generation (up to 12 kW) and small- to medium-scale generation (greater than 12kW up to 1MW). These incentives are expected to support continued growth in DER adoption.

In addition to new connections, Hydro One continues to see refurbishment and reinvestment in existing DER facilities as assets age. While such activities do not typically require distribution system upgrades, some projects involve capacity increases that may trigger incremental system requirements. This trend is expected to become more pronounced with the introduction of the IESO's forthcoming Local Generation program, anticipated to launch in 2026.[3] This program is intended to re-contract approximately 2,000 MW of existing generation capacity, including biogas, wind, solar, and CHP facilities, whose current contracts are expiring over the next decade. While contract renewal alone is not expected to drive significant distribution system impacts, the program's focus on enabling facility expansions and new-build opportunities may result in additional connection-related investments

Table 1 provides a summary of DER applications subject to a Connection Impact Assessment (CIA) from 2020-2025.

[3] https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Local-Generation-Program

Table 1 - DER Applications for CIA 2020-2025

Project Type		2020	2021	2022	2023	2024	2025	Total
Mid/Large DER	**Projects**	13	14	15	14	13	13	82
	Capacity (MW)	323.5	354.8	689.0	511.6	1,210.6	918.4	4,008.0
Small DER	**Projects**	81	52	69	87	81	102	472
	Capacity (MW)	81.9	54.8	68.0	101.78	103.6	113.1	523.0
Total	**Projects**	94	66	84	101	94	115	554
	Capacity (MW)	405.3	409.5	757.0	613.4	1,314.2	1,031.5	4,531.0

3.4.3 CONNECTION FORECAST

Since 2020, Hydro One has connected over 3,500 DERs with a combined capacity of approximately 191MW. The majority of these DERs are renewable and have been connected under IESO programs. Table 2 details the additions to the system in terms of quantity and capacity of DER projects from each of the three segments.

Table 2 - DER Projects Connected from 2020-2025

Year		2020	2021	2022	2023	2024	2025	Total
Mid/Large DER	**Projects**	10	8	7	2	4	**1**	**32**
	Capacity (MW)	37.2	29.3	21.3	11.5	12.1	5.0	**116.2**
Small DER	**Projects**	57	70	22	47	56	56	**308**
	Capacity (MW)	20.2	9.0	1.6	4.1	6.9	5.6	**47.4**
Micro	**Projects**	143	324	528	778	764	650	**3187**
	Capacity (MW)	1.3	2.8	4.5	6.6	6.8	5.8	**27.8**
Total	**Projects**	210	402	557	827	824	707	**3527**
	Capacity (MW)	58.6	41.1	27.4	22.2	25.7	16.5	**191.4**

As shown in Table 2, the majority of existing DER installations predominantly consist of micro-embedded generation projects. Historically, these installations were limited to a generation capacity of 10kW or less per unit and collectively represent less than 10% of the capacity of the total installed DER capacity on Hydro One's system. Effective May

2026, the OEB revised the definition of micro-embedded generation to include projects with a generation capacity of up to 12kW.[4]

For the purposes of forecasting, Hydro One has also considered and incorporated the findings of the IESO's Distributed Energy Resources (DER) Potential Study (Dunsky Study), prepared by Dunsky Energy + Climate Advisors. The Dunsky Study identifies the types and volumes of DER that could materialize in Ontario over a 10 year time period beginning in 2023, and provides three projection models based on three different scenarios: (i) a 'Business-As-Usual' projection, (ii) a 'Business-As-Usual +' which includes a slightly increased projection, and (iii) an 'Accelerated' projection where significantly increased efforts are made to adopt and integrate DER within the province of Ontario.

As of January 1, 2026, Hydro One has accumulated three years of actual DER connection data, which was used to assess the applicability of the Dunsky Study projections to Hydro One's distribution system. Hydro One evaluated the study's three projection models against observed historical trends for Micro, Small and Mid/Large DER categories to determine the best alignment.[5]

Table 3 presents the projected number of DER connections over the 2026 to 2032 period, differentiated by renewable and non-renewable resource types. Projections for 2026 and 2027 are based on current DER programs and initiatives, while projections for 2028 to 2032 are also informed by the findings of the Dunsky Study.

[4] Notice of Final Amendments to the Distribution System Code, December 19, 2025 (EB-2019-0207).
[5] While the Dunsky Study does not directly categorize DER in the same manner as Hydro One does for business planning purposes, Hydro One approximated the DSC prescribed categories of Small DER, Medium/Large DER and micro-embedded generation that correspond to the categories used in the study.

Table 3 - Number of DER Forecast for 2026-2032

Project Type		Forecast						
		2026	2027	2028	2029	2030	2031	2032
Non Renewable Energy Projects	Mid/Large DER	16	16	32	32	32	32	32
	Small DER	2	2	10	10	10	10	10
	Micro	20	20	20	20	20	20	20
Renewable Energy Projects	Mid/Large DER	8	8	16	16	16	16	16
	Small DER	60	60	285	285	285	285	285
	Micro	1,306	1,306	1,615	1,615	1,615	1,615	1,615

The forecast of non-renewable energy projects consists of combined heat and power (CHP), energy storage systems, natural gas, diesel etc. connecting behind the meter for the purpose of load displacement or peak shaving. The majority of energy storage systems are lithium-ion batteries as the technology becomes increasingly more accessible. The majority of forecasted renewable energy projects are expected to be solar and are expected to connect under the Ontario Net Metering program or the Save on Energy program.

Net-metering and Save on Energy applications are expected to occur throughout Hydro One's service territory. Hydro One does not currently have any information that would predict or suggest a specific geographic concentration of activity. In the absence of this information, Hydro One has assumed that applications will materialize broadly across the system consistent with historical experience. Hydro One's distribution system has sufficient overall capacity to support the projected scale of DER adoption; however, localized feeder or station constraints, such as thermal, short-circuit, and system limits, may restrict connections in certain areas to maintain equipment protection, power quality, and system reliability.

3.4.4 DER HOSTING CAPACITY

The Hydro One distribution system is predominantly radial in design, with limited capability to transfer supply between feeders. While the distribution system does have some capacity to accommodate DER connections, it was originally designed for one-way power

flow, with electricity delivered from the transmission system downstream to end-use customers. As a result, this design inherently limits the capacity available to support DER connections without additional system enhancements.

At a provincial level, Hydro One expects that the distribution system has sufficient capacity to accommodate the forecasted levels of DER adoption. However, localized and regional system constraints may limit available capacity in certain areas, which can affect DER connection opportunities, as discussed below.

The availability of DER capacity on Hydro One's distribution system may be limited in certain areas due to thermal limits, short-circuit constraints or system limits at the feeder or station level. These constraints reflect the requirement to operate distribution system assets within established ratings, prevent equipment damage associated with excessive reverse power flow, maintain acceptable power quality for customers, and ensure system reliability and resilience under both normal and contingency conditions.

As of December 31, 2025**,** 75 feeders (approximately 2.3% of Hydro One's distribution feeders), as identified in Table 4, are unable to accommodate additional DER connections. Hydro One has planned system upgrades that would address short-circuit constraints at Wanstead TS. These upgrades are expected to enable additional DER capacity on 24 feeders as indicated by an asterisk (*) in Table 4. For the remaining constrained feeders in Table 4, there are no planned capital investments within the 2028 to 2032 period specifically targeted at mitigating the limitations affecting the stations and associated feeders.

Table 4 - Restricted Feeders for DER Connections

Feeder Name	Type of Restriction	Number of Customers[6]
ALVINSTON DS - F1 *	Short Circuit Limit	378
ALVINSTON DS - F2 *	Short Circuit Limit	1
ALVINSTON DS - F3 *	Short Circuit Limit	215
BRIGDEN DS - F1 *	Short Circuit Limit	327
BRIGDEN DS - F2 *	Short Circuit Limit	279
BRIGDEN DS - F3 *	Short Circuit Limit	235
CASS BRIDGE DS - F1	Restricted Station (upstream)	407
CASS BRIDGE DS - F2	Restricted Station (upstream)	315
CASS BRIDGE DS - F3	Restricted Station (upstream)	353
DIXONS CORNERS DS - F1	Restricted Station (upstream)	723
DIXONS CORNERS DS - F2	Restricted Station (upstream)	300
DIXONS CORNERS DS - F3	Restricted Station (upstream)	408
GLEN BECKER DS - F1	Restricted Station (upstream)	642
GLEN BECKER DS - F2	Restricted Station (upstream)	424
GLEN BECKER DS - F3	Restricted Station (upstream)	447
HECKSTON DS - F1	Restricted Station (upstream)	480
HECKSTON DS - F2	Restricted Station (upstream)	646
HECKSTON DS - F3	Restricted Station (upstream)	298
JOHNSTOWN DS - F1	Restricted Station (upstream)	549
JOHNSTOWN DS - F2	Restricted Station (upstream)	626
KLEINBURG TS - M5	Short Circuit Limit	2,292
KLEINBURG TS - M6	Short Circuit Limit	1,133
KLEINBURG TS - M7	Short Circuit Limit	3,495
KLEINBURG TS - M8	Short Circuit Limit	1,232
LEAMINGTON DS #2 - F1	Restricted Station (upstream)	N/A
LEAMINGTON DS #2 - F2	Restricted Station (upstream)	262
LEAMINGTON DS #2 - F3	Restricted Station (upstream)	520
LEAMINGTON TS DESN 1 - M22	Restricted Station	228 + (1,574)
LEAMINGTON TS DESN 1 - M24	Restricted Station	19
LEAMINGTON TS DESN 1 - M26	Restricted Station	609
LEAMINGTON TS DESN 1 - M28	Restricted Station	504
LEAMINGTON TS DESN 1 - M30	Restricted Station	468 + (782)
LEAMINGTON TS DESN 1 - M32	Restricted Station	24
MARTHAVILLE DS - F1 *	Short Circuit Limit	385
MARTHAVILLE DS - F2 *	Short Circuit Limit	217

[6] 'Number of Customers' includes the number of directly connected customers and where applicable, in brackets, is the count of downstream customers connected to that feeder via an F class distribution feeder. Those F class feeders also have their own entry in the table.

MARTHAVILLE DS - F3 *	Short Circuit Limit	415
MORRISBURG TS - M23	Restricted Station	15 + (1,175)
MORRISBURG TS - M24	Restricted Station	1
MORRISBURG TS - M25	Restricted Station	682 + (4,368)
MORRISBURG TS - M26	Restricted Station	(3,186)
MURILLO DS - F1	Thermal Limit	1,617
MURILLO DS - F2	Thermal Limit & SC Limit	928
MURILLO DS - F3	Thermal Limit	1,105
MURILLO DS - F4	Thermal Limit & SC Limit	855
MURILLO DS - F5	Thermal Limit	159
MURILLO DS - F6	Thermal Limit & SC Limit	1,014
MURILLO DS - K3.4F	Thermal Limit	1,038
OIL SPRINGS DS - F1 *	Short Circuit Limit	248
OIL SPRINGS DS - F2 *	Short Circuit Limit	95
SOUTH GOWER DS - F1	Restricted Station (upstream)	248
SOUTH GOWER DS - F2	Restricted Station (upstream)	799
SOUTH GOWER DS - F3	Restricted Station (upstream)	466
WANSTEAD TS - M1 *	Short Circuit Limit	65 + (2,119)
WANSTEAD TS - M2 *	Short Circuit Limit	1067 + (1,067)
WANSTEAD TS - M3 *	Short Circuit Limit	49
WANSTEAD TS - M4 *	Short Circuit Limit	47 + (1,184)
WARWICK DS - F1 *	Short Circuit Limit	291
WARWICK DS - F2 *	Short Circuit Limit	152
WARWICK DS - F3 *	Short Circuit Limit	378
WHEATLEY DS #2 - F1	Restricted Station (upstream)	577
WHEATLEY DS #2 - F2	Restricted Station (upstream)	657
WHEATLEY DS #2 - F3	Restricted Station (upstream)	340
WINCHESTER ST LAW DS - F1	Restricted Station (upstream)	277
WINCHESTER ST LAW DS - F2	Restricted Station (upstream)	285
WINCHESTER ST LAW DS - F3	Restricted Station (upstream)	47
WYOMING CHURCHILL DS - F1 *	Short Circuit Limit	531
WYOMING CHURCHILL DS - F2 *	Short Circuit Limit	595
WYOMING NORTH DS - F1 *	Short Circuit Limit	280
WYOMING NORTH DS - F2 *	Short Circuit Limit	127
WYOMING NORTH DS - F3 *	Short Circuit Limit	297

Additionally, 130 feeders (approximately 4% of Hydro One's distribution feeders) have reached their capacity to accommodate additional micro-embedded generation, although they may be able to support larger projects subject to the outcome of a Connection Impact

Assessment (CIA). These micro-embedded generation constrained feeders are identified in Table 5 and represent potential candidates for enabling upgrades under the investments proposed in Section 3.4.5.1 of this document, and DSP Section 3.11, D-SS-07.

Table 5 - Restricted Feeders for Micro-embedded Generation Connections

Feeder Name	Type of Restriction	Number of Customers
ABBEY DS - F3	Micro Limit	693
AMULREE DS - F1	Micro Limit	429
AMULREE DS - F2	Micro Limit	401
APPIN DS - F2	Micro Limit	264
ARGYLE DS - F1	Micro Limit	203
ATHENS DS - F1	Micro Limit	N/A
AUBURN DS - F3	Micro Limit	150
BEST DS - F2	Micro Limit	300
BLENHEIM DS - F2	Micro Limit	444
BOTANY DS - F3	Micro Limit	153
BRANT TS - M22	Micro Limit	1,700
BROCKVIL WATER DS - F2	Micro Limit	N/A
CALSTOCK DS - F1	Micro Limit	117
CANFIELD DS - F1	Micro Limit	478
CANFIELD DS - F3	Micro Limit	272
CHAPLEAU DS - F2	Micro Limit	1
CLARENCE DS - F3	Micro Limit	N/A
CLAYTON DS - F3	Micro Limit	244
COLDSTREAM DS - F1	Micro Limit	337
COMET DS - F2	Micro Limit	224
COMMANDA DS - F1	Micro Limit	344
COTTAM DS - F2	Micro Limit	240
COTTAM DS - F4	Micro Limit	726
CROSBY TS - M1	Micro Limit	3,192
DEMORESTVILLE DS - F1	Micro Limit	480
DEVLIN DS - F2	Micro Limit	233
DOVER CENTRE DS - F2	Micro Limit	486
DOVER CENTRE DS - F3	Micro Limit	692
DUBLIN DS - F2	Micro Limit	285
DUNBOYNE DS - F1	Micro Limit	712
ERIEAU DS - F3	Micro Limit	54
ESSEX DS - F1	Micro Limit	312
ESSEX DS - F2	Micro Limit	1,082

FERNDALE DS - F2	Micro Limit	1,396
FOREST JURA DS - F4	Micro Limit	N/A
FOREST UNION DS - F3	Micro Limit	51
GLENCOE DS - F3	Micro Limit	117
GODERICH TS - M6	Micro Limit	N/A
GODERICH TS - M8	Micro Limit	N/A
GREENBANK DS - F3	Micro Limit	148
HARRISTON DS #2 - F1	Micro Limit	300
HARROWSMITH DS - F4	Micro Limit	1,291
HAYCROFT DS - F1	Micro Limit	301
HAYCROFT DS - F3	Micro Limit	162
HIGHGATE DS - F2	Micro Limit	379
JARVIS DS - F3	Micro Limit	420
JARVIS TS - M7	Micro Limit	N/A
KENORA DS - F1	Micro Limit	771
KENORA DS - F3	Micro Limit	75
KERWOOD DS - F1	Micro Limit	278
KINCARDINE DS #2 - F2	Micro Limit	233
KINGSTON GARDINER TS DESN2 - M24	Micro Limit	1,263
LAMBTON TS - M8	Micro Limit	N/A
LUCKNOW DS - F2	Micro Limit	288
MADOC DS #2 - F3	Micro Limit	174
MALDEN TS - M7	Micro Limit	147
MANSFIELD DS - F2	Micro Limit	99
MATACHEWAN DS - F2	Micro Limit	50
MCNAB DS - F3	Micro Limit	31
MERLIN DS - F1	Micro Limit	224
MERLIN DS - F2	Micro Limit	718
NORTHCOTE DS - F3	Micro Limit	711
OWEN SOUND DS #2 - F2	Micro Limit	238
PAISLEY DS #2 - F1	Micro Limit	443
PAISLEY DS #2- F2	Micro Limit	269
PAKENHAM DS - F2	Micro Limit	95
PELEE ISLAND DS - F1	Micro Limit	125
PETERBOROUGH LANGTON DS - F2	Micro Limit	8
PETERBOROUGH LANSDOWNE DS - F1	Micro Limit	N/A
PORT ALBERT DS - F2	Micro Limit	309
PORT ALBERT DS - F3	Micro Limit	779

PORT LAMBTON DS - F3	Micro Limit	158
PRECIOUS CORNERS DS - F1	Micro Limit	361
PROSPECT DS - F2	Micro Limit	497
PROSPECT HILL DS - F1	Micro Limit	310
RED ROCK DS - F3	Micro Limit	519
REDDENDALE DS - F1	Micro Limit	578
REDDENDALE DS - F2	Micro Limit	160
REDDENDALE DS - F3	Micro Limit	524
RICE DS - F1	Micro Limit	6
ROCKWOOD DS - F2	Micro Limit	74
ROTHSAY DS - F2	Micro Limit	230
SAUBLE BEACH DS - F1	Micro Limit	815
SCIENCE HILL DS - F3	Micro Limit	183
SHEFFIELD DS - F1	Micro Limit	680
SHEFFIELD DS - F2	Micro Limit	11
SHEFFIELD DS - F3	Micro Limit	13
SHELBURNE DS - 4.16 kV - F2	Micro Limit	664
SILVER CREEK DS - F1	Micro Limit	14
SIMCOE EVERGREEN DS - F3	Micro Limit	N/A
SLEEMAN DS - F1	Micro Limit	247
SLEEMAN DS - F2	Micro Limit	145
SMITHS FALLS DS - F3	Micro Limit	78
SMITHS FLS LORNE DS - F2	Micro Limit	259
SNOW ROAD DS - F2	Micro Limit	873
SOUTH MIDDLE ROAD TS - M61	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M62	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M63	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M64	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M65	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M66	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M67	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M68	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M69	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M70	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M71	Micro Limit	N/A
SOUTH MIDDLE ROAD TS - M72	Micro Limit	N/A
SPENCERVILLE DS - F2	Micro Limit	624
ST MARYS DS - F2	Micro Limit	227
ST MARYS DS - F3	Micro Limit	167
STIRLING DS - F2	Micro Limit	487

STRAFFORDVILLE DS - F3	Micro Limit	570
STRATFORD EASTHP DS - F1	Micro Limit	268
TARA DS #2 - F3	Micro Limit	169
THAMESVILLE NORTH DS - F1	Micro Limit	404
THAMESVILLE NORTH DS - F3	Micro Limit	241
THEDFORD DS - F2	Micro Limit	424
TILBURY PELTIER DS - F1	Micro Limit	284
TILBURY PELTIER DS - F2	Micro Limit	405
VANDELEUR DS - F1	Micro Limit	724
VIRGINIA BEACH DS - F1	Micro Limit	10
WALKERTON DS #2 - F2	Micro Limit	381
WALLACEBURG DS - F1	Micro Limit	153
WALLACEBURG DS - F2	Micro Limit	271
WALLACEBURG DS - F3	Micro Limit	223
WARKWORTH DS - F1	Micro Limit	722
WAUBAUSHENE NORTH DS - F3	Micro Limit	10
WAUPOOS DS - F1	Micro Limit	767
WAUPOOS DS - F2	Micro Limit	536
WELLINGTON DS - F1	Micro Limit	453
WEST LORNE DS - F1	Micro Limit	310
WOODSTOCK EAST DS - F1	Micro Limit	252

In addition to the feeders identified in Tables 4 and 5, Hydro One has identified further feeders with limited capacity to accommodate incremental micro-embedded generation connections. In the absence of measures to relieve these constraints, Hydro One anticipates that the number of unaccommodated DER connections requests will increase as DER adoption continues to grow. This expectation is consistent with the projected trends outlined in the study prepared for the IESO by Dunsky,[7] as additional feeders are expected to reach their capacity limits over time.

Hydro One provides information on station and feeder capacity to assist prospective DER proponents in identifying suitable locations for their projects. This information is made available on Hydro One's website in two formats. First, an online Station Capacity Calculator tool enables prospective DER Customers to estimate available DER capacity

7 Dunsky Energy + Climate Advisors, Ontario's Distributed Energy Resources (DER) Potential Study Volume I: Results & Recommendations, September 28 2022, p. 57.

based on a selected feeder and proposed project size. Second, Hydro One contributes regular data updates to the OEB's Centralized Capacity Information Map (CCIM), which provides transparent and accessible data about the province's electrical grid capacity for both load and DER connections.

A local distributor embedded within Hydro One's distribution system that wants 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 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 RENEWABLE ENERGY GENERATION (REG) INVESTMENTS

Consistent with regulatory requirements, Hydro One undertakes Renewable Energy Generation (REG) investments to enable the connection of renewable generation facilities to its distribution system.

Historically, the Feed-in-Tariff (FIT) program represented the primary source of REG-related investment activity. At present, REG investments are predominantly driven by connection requests under the net-metering program.

Through its *Framework for Energy Innovation* (FEI) report, the OEB expects distributors to plan, design, and operate their systems in a manner that proactively considers the anticipated impacts of DER adoption.[8] In response, Hydro One is proposing a new investment as outlined in DSP Section 3.11, D-SS-07, to alleviate hosting capacity constraints on micro-embedded generation restricted feeders and proposes to recover 40% of the cost of these investments as Renewable Enabling Improvement (REI) investments under section 79.1 of the OEB Act and O. Reg. 330/09 under the OEB Act. Based on a representative sample of system assessments and engineering studies, approximately 40% of the proposed system enhancements in DSP Section 3.11, D-SS-07

[8] *Framework for Energy Innovation: Setting a Path Forward for DER Integration*, OEB, January 2023, p. 14

are expected to qualify as REI investments. This allocation is supported by historical data indicating a high degree of confidence that almost all anticipated residential DER connections will be renewable in nature.

Refer to Attachment 7 for the RGCRP Funding Request Letter and the associated Appendices 2FA 2FB 2FC HONI - Hydro One Distribution RGCRP Revenue Requirement Model and 2FA 2FB 2FC PRZ – Peterborough RZ RGCRP Revenue Requirement Model.

Hydro One is proposing REG investments solely to improve the ability of the local distribution system to accommodate renewable energy resources. As these investments are locally driven and are not identified through regional planning activities, they do not fall within the scope of regional planning processes overseen by the IESO. Where a DER connection is proposed on a shared feeder, Hydro One coordinates with the affected neighbouring LDC(s) to ensure that any required investments are appropriately scoped and aligned across service territories.

3.4.6 FEI INVESTMENTS AND CAPACITY INCREASE

In the Framework for Energy Innovation report, the OEB set out its expectations that distributors plan, design, and operate their systems in a way that accounts for the anticipated impacts of DER. The OEB expects that these activities will be informed by forecast DER adoption, helping ensure that distribution customers continue to receive reliable distribution service and that service quality is not degraded by DER integration. Doing so will also ensure that limitations of the distribution system do not pose an undue barrier to customers exercising their choice to adopt DERs. Customers would still be expected to pay for connection costs that are specific to their DER (for example, protection systems that are only required due to the existence of that facility). However, a distributor may propose system investments that enable DER integration, where the investments are not necessarily attributable to a given customer's facility or group of facilities and are justifiable in light of expected DER adoption and the benefits that may be conferred.[9]

[9] *Framework for Energy Innovation: Setting a Path Forward for DER Integration*, OEB, January 2023, p. 14

In the current 2023-2027 rate period, Hydro One has taken several actions to increase DER connection capacity on the distribution system. This includes the following initiatives:

- Updated connection requirements to permit the use of smart inverter settings for customer-owned equipment. This enhancement has increased the available incremental capacity on a typical feeder for residential DER connections by approximately 42%. Since October 2022, this change has enabled Hydro One to issue an additional 1,104 connection offers, resulting in 517 additional residential DER connections that would have otherwise been unable to proceed.
- Undertook an assessment of transformer technical limits, including their ability to safely accommodate reverse power flow, to identify opportunities for additional DER capacity. As a result, four feeders that were previously fully constrained with respect to DER connections have been reclassified as unconstrained, with up to 8.4MW of incremental capacity now available for new DER connections.
- Worked with Hydro One Transmission to reassess transformer stations with identified short-circuit constraints and determine that the projected volume of micro embedded generation can be accommodated without exceeding the standards for short circuit levels, given the non-material contribution of these smaller-scale resources.
- Established and approved a solution that utilizes utility-grade protection systems installed at customer sites, enabling qualifying behind-the-meter load displacement projects to connect to the distribution system without reducing available DER feeder thermal capacity.
- Deployed new equipment and technologies, including feeder-level line sensors, to enhance monitoring of distribution system loading. These investments have improved the accuracy of feeder loading assessments and supported the refinement of feeder capacity limits. This has enabled Hydro One to increase the utilization of existing distribution assets and create incremental capacity to accommodate additional DER connections. These ongoing efforts have resulted in over 13MW of additional capacity on 25 feeders.
- Ongoing assessment of the use of flexible capacity arrangements to address system constraints and related technical limitations. Where appropriate, flexible connection options have been offered to proponents. While several projects have

been presented with this option, most have elected not to proceed under a flexible capacity framework. As of December 31, 2025, a single project is advancing under such an arrangement, providing Hydro One with an opportunity to evaluate the operational performance and customer impacts of flexible capacity connections.

To support broader integration and enablement of DERs in the upcoming 2028-2032 planning period, Hydro One plans to undertake targeted distribution system investments to create additional hosting capacity on restricted feeders for micro-embedded generation connections, and to prioritize these investments to meet demonstrated customer demand. These enabling investments can include upgrades such as regulator installations, system reconfigurations, monitoring, and control enhancements required to safely accommodate additional generation. The distribution system investments proposed to relieve DER capacity constraints over the 2028-2032 period are detailed in DSP Section 3.11, D-SS-07. In the absence of these investments, customers connected to currently constrained feeders will be unable to proceed with their micro-embedded generation installations. Furthermore, the number of constrained feeders is expected to increase over time as DER adoption continues to grow.

3.4.7 ATTACHMENTS

The following attachments are provided as part of this section

Table 6 - Attachments

Attachment	Report
1	2023 Front of Meter DER
2	2023 Behind the Meter DER
3	2024 Front of Meter DER
4	2024 Behind the Meter DER
5	2025 Front of Meter DER
6	2025 Behind the Meter DER
7	7.0 RGCRP Funding Request
7.1	Appendices 2FA 2FB 2FC HONI - Hydro One Distribution RGCRP Revenue Requirement
7.2	Appendices 2FA 2FB 2FC Peterborough RZ RGCRP Revenue Requirement Model

Number and MW of Front of the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2023

The breakdown of front-of-the-meter Distributed Energy Resources (FTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by station as of December 31, 2023 is as follows:

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
AGIMAK DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
AGUASABON DS	6.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.09
ALLANBURG TS	70.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	1.36
ALLISTON TS	41.00	1.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.00	1.03
ALMONTE TS	112.00	21.79	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	113.00	21.80
ARDOCH DS	13.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.12
ARMITAGE TS DESN1	73.00	7.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.00	7.18
ARMITAGE TS DESN2	93.00	1.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	93.00	1.26
ARNPRIOR TS	119.00	22.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	119.00	22.20
AYLMER TS	50.00	2.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00	2.47
BALLINAFAD MS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
BARWICK TS	103.00	25.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.00	25.96
BATTERSEA DS	70.00	1.22	0.00	0.00	1.00	0.25	0.00	0.00	4.00	2.00	75.00	3.47
BEAMSVILLE TS	8.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.17
BEARDMORE DS #2	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.00	0.00	0.00	1.00	6.00
BEAVERTON TS	300.00	57.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300.00	57.58
BELLE RIVER TS	166.00	3.19	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	167.00	13.19
BELLEVILLE TS	205.00	52.66	0.00	0.00	1.00	0.25	0.00	0.00	1.00	0.50	207.00	53.41
BILBERRY CREEK TS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
BLOOMSBURG DS	17.00	13.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	13.24

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
BRACEBRIDGE TS	15.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.13
BRANT TS	107.00	9.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	9.67
BRANTFORD TS	11.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	1.00	8.10	12.00	8.21
BROCKVILLE TS	219.00	32.42	0.00	0.00	0.00	0.00	0.00	0.00	2.00	1.00	221.00	33.41
BROWN HILL TS	212.00	32.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	212.00	32.85
BUCHANAN TS	14.00	0.34	0.00	0.00	1.00	2.85	0.00	0.00	0.00	0.00	15.00	3.19
BUNTING TS	0.00	0.00	0.00	0.00	0.00	0.00	2.00	4.00	0.00	0.00	2.00	4.00
BURLEIGH DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CALEDONIA TS	31.00	20.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	20.92
CALSTOCK DS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
CAMPBELL TS DESN2	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CENTRALIA TS	145.00	5.13	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.50	147.00	5.63
CHESTERVILLE TS	100.00	21.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	21.32
CLARABELLE TS	80.00	2.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.00	2.51
CLARENCE DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
CLARKE TS	63.00	1.34	0.00	0.00	1.00	0.30	0.00	0.00	3.00	0.75	67.00	2.39
CLEARWATER BAY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
COBDEN DS	37.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.00	0.36
COBDEN TS	137.00	4.41	0.00	0.00	1.00	0.50	0.00	0.00	0.00	0.00	138.00	4.90
COCHRANE WEST DS	19.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.19
COMMERCE WAY TS	91.00	2.76	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	92.00	20.76
CONSTANCE DS	97.00	1.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	97.00	1.43
CRAIG DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CRILLY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CROSBY TS	5.00	40.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	40.01

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
CROSBY TS DESN1	49.00	21.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	21.86
CROWLAND TS	15.00	10.27	1.00	9.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	19.27
CRYSTAL FALLS TS	43.00	5.61	0.00	0.00	0.00	0.00	3.00	11.50	0.00	0.00	46.00	17.11
CUMBERLAND DS	21.00	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.38
DEEP RIVER DS	15.00	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.27
DES JOACHIMS DS	3.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.26
DOBBIN DS	24.00	0.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.00	0.32
DOBBIN TS	189.00	14.02	1.00	10.00	0.00	0.00	0.00	0.00	1.00	0.10	191.00	24.12
DOUGLAS POINT TS	117.00	2.07	3.00	11.05	0.00	0.00	0.00	0.00	0.00	0.00	120.00	13.12
DRYDEN TS	31.00	10.27	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.38	33.00	10.65
DUART TS DESN1	103.00	10.91	1.00	10.00	0.00	0.00	0.00	0.00	1.00	0.25	105.00	21.16
DUNDAS TS	211.00	4.77	0.00	0.00	0.00	0.00	0.00	0.00	2.00	8.49	213.00	13.26
DUNNVILLE TS	24.00	0.69	2.00	9.90	0.00	0.00	0.00	0.00	1.00	4.11	27.00	14.70
DYMOND TS	59.00	9.89	0.00	0.00	0.00	0.00	1.00	9.50	0.00	0.00	60.00	19.39
EAR FALLS TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
EDGEWARE TS	107.00	3.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	3.73
ELLIOT LAKE TS	14.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.20
ELMIRA TS	27.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.23	29.00	3.75
ENFIELD TS DESN 1	92.00	1.52	3.00	35.85	0.00	0.00	0.00	0.00	0.00	0.00	95.00	37.37
ESPANOLA TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
ETON DS	29.00	0.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.00	0.32
EVERETT TS	108.00	1.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	108.00	1.07
FALLOWFIELD DS	0.00	0.00	0.00	0.00	1.00	5.55	0.00	0.00	0.00	0.00	1.00	5.55
FAUQUIER DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
FERGUS TS	199.00	2.92	3.00	41.20	0.00	0.00	0.00	0.00	1.00	0.14	203.00	44.25

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
FOREST JURA DS	98.00	1.36	2.00	16.50	0.00	0.00	0.00	0.00	0.00	0.00	100.00	17.86
FOREST LEA DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
FORT WILLIAM TS	2.00	15.90	0.00	0.00	1.00	3.20	0.00	0.00	0.00	0.00	3.00	19.10
FRONTENAC TS	130.00	2.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	130.00	2.23
GALT TS	16.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.14
GODERICH TS	79.00	1.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.00	1.14
GRAND BEND EAST DS	42.00	1.00	1.00	0.80	1.00	0.50	0.00	0.00	0.00	0.00	44.00	2.30
GREELY DS	67.00	1.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	1.57
HANOVER TS	362.00	8.78	1.00	22.17	0.00	0.00	2.00	0.28	3.00	0.75	368.00	31.98
HARROWSMITH DS	139.00	1.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	139.00	1.22
HAVELOCK TS	242.00	11.50	0.00	0.00	0.00	0.00	1.00	18.00	0.00	0.00	243.00	29.50
HAWTHORNE TS	82.00	11.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.00	11.72
HEARST TS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
HERRIDGE LAKE DS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
HIGHBURY TS	35.00	7.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.00	7.48
HINCHINBROOKE DS	39.00	0.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.58
HOLLAND TS	77.00	2.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.00	2.41
INGERSOLL TS	132.00	21.63	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.25	133.00	21.88
INNISFIL MS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
IROQUOIS FALLS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
JARVIS TS	33.00	4.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	4.20
KAPUSKASING TS	64.00	8.58	0.00	0.00	0.00	0.00	4.00	22.00	0.00	0.00	68.00	30.58
KEITH TS DESN1	6.00	20.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	20.04
KENORA DS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14
KENT TS DESN1	178.00	2.62	3.00	30.00	0.00	0.00	0.00	0.00	0.00	0.00	181.00	32.62

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
KENT TS DESN2	125.00	1.22	2.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	127.00	21.22
KINGSTON GARDINER TS DESN1	147.00	42.26	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	148.00	52.26
KINGSTON GARDINER TS DESN2	34.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.36	35.00	0.97
KINGSVILLE TS	197.00	4.21	3.00	25.80	0.00	0.00	0.00	0.00	1.00	12.00	201.00	42.01
KIRKLAND LAKE TS	34.00	8.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	8.50
KLEINBURG TS	172.00	3.54	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.23	173.00	6.77
LAFOREST ROAD DS	1.00	0.01	0.00	0.00	0.00	0.00	1.00	14.00	0.00	0.00	2.00	14.01
LAMBTON TS	42.00	40.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.00	40.60
LARCHWOOD TS	34.00	0.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	0.85
LAUZON TS DESN1	3.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.23
LAUZON TS DESN2	149.00	2.99	2.00	20.00	1.00	0.25	0.00	0.00	0.00	0.00	152.00	23.24
LDC OWNED STATION	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
LEAMINGTON TS DESN 1	166.00	3.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	166.00	3.25
LEAMINGTON TS DESN 2	43.00	1.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.00	1.07
LINDSAY TS	233.00	45.51	0.00	0.00	1.00	0.50	1.00	0.50	1.00	0.34	236.00	46.84
LODGEROOM DS	67.00	1.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	1.08
LONGLAC TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
LONGUEUIL TS	143.00	51.39	1.00	0.01	3.00	0.46	0.00	0.00	0.00	0.00	147.00	51.86
LONGWOOD TS	158.00	3.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	158.00	3.31
MALDEN TS	109.00	12.35	3.00	29.80	0.00	0.00	0.00	0.00	0.00	0.00	112.00	42.15
MANITOULIN TS	101.00	0.92	2.00	5.60	0.00	0.00	0.00	0.00	0.00	0.00	103.00	6.52
MANITOUWADGE DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
MANITOUWADGE TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
MANOTICK DS	18.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	19.00	0.95

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
MARATHON DS	17.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.12
MARGACH DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
MARIONVILLE DS	64.00	0.59	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.75	66.00	1.34
MARTINDALE TS	48.00	10.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.00	10.90
MASSEY DS	13.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.13
MATTAWA DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
MAZINAW DS	12.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.10
MEAFORD TS	64.00	1.15	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	65.00	19.15
MIDHURST TS DESN1	244.00	37.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	244.00	37.72
MINDEN TS	86.00	2.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.00	2.25
MODELAND TS	5.00	50.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	10.84	7.00	60.84
MONTEITH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MORRISBURG TS	115.00	20.67	1.00	30.00	0.00	0.00	0.00	0.00	0.00	0.00	116.00	50.67
MOUNTAIN CHUTE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MURILLO DS	100.00	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	1.19
MUSKOKA TS	222.00	29.01	0.00	0.00	0.00	0.00	1.00	5.00	0.00	0.00	223.00	34.01
NAKINA DS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.50	1.00	1.50
NAPANEE TS	230.00	59.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	230.00	59.97
NAVAN DS	11.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.09
NEBO TS DESN1	90.00	0.98	0.00	0.00	1.00	3.20	0.00	0.00	0.00	0.00	91.00	4.18
NELSON TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NESTOR FALLS DS	13.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.12
NEWINGTON DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
NIPIGON DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
NORFOLK TS	131.00	19.56	2.00	19.90	0.00	0.00	0.00	0.00	0.00	0.00	133.00	39.46

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
NORTH BAY TS	1.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.08
NORTH SHORE DS	17.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.16
NORTHBROOK DS	31.00	0.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.51
ORANGEVILLE TS DESN1	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
ORANGEVILLE TS DESN2	361.00	5.25	5.00	44.23	0.00	0.00	0.00	0.00	0.00	0.00	366.00	49.48
ORILLIA TS	183.00	31.77	0.00	0.00	0.00	0.00	1.00	1.65	1.00	1.06	185.00	34.48
ORLEANS TS	70.00	3.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	3.07
OTONABEE TS DESN1	17.00	2.33	0.00	0.00	1.00	1.60	0.00	0.00	0.00	0.00	18.00	3.93
OTONABEE TS DESN2	235.00	9.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	235.00	9.12
OWEN SOUND TS	370.00	10.49	0.00	0.00	1.00	0.10	0.00	0.00	0.00	0.00	371.00	10.59
PALERMO TS	0.00	0.00	0.00	0.00	1.00	2.10	0.00	0.00	0.00	0.00	1.00	2.10
PALMERSTON TS	256.00	4.66	1.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	257.00	5.16
PARRY SOUND TS	57.00	3.62	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.00	58.00	5.62
PEMBROKE TS	33.00	0.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	0.57
PETAWAWA DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
PIC DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
PICTON TS	218.00	28.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	218.00	28.64
PLEASANT TS DESN1	23.00	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.00	0.28
PORT ARTHUR TS #1	30.00	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.27
PORT COLBORNE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
PORT HOPE TS DESN1	237.00	34.84	0.00	0.00	1.00	0.01	0.00	0.00	0.00	0.00	238.00	34.85
PUSLINCH DS	96.00	1.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.00	1.55
RAMORE TS	12.00	8.11	0.00	0.00	0.00	0.00	1.00	0.52	0.00	0.00	13.00	8.63
RED LAKE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
RED ROCK DS	29.00	1.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.00	1.25

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
ROCKLAND DS	6.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.05
ROCKLAND EAST DS	14.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.13
RUSSELL DS	7.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.13
SCHREIBER WINNIPEG DS	9.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.07
SEAFORTH TS	102.00	2.59	1.00	15.00	0.00	0.00	0.00	0.00	0.00	0.00	103.00	17.59
SHABAQUA DS	9.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.09
SHARBOT DS	22.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	0.19
SIDNEY TS	246.00	3.94	0.00	0.00	0.00	0.00	1.00	10.00	0.00	0.00	247.00	13.94
SIOUX NARROWS DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
SMITHS FALLS TS	257.00	83.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	257.00	83.26
SOUTH GLOUCESTER DS	13.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.15
SOUTH MARCH TS	66.00	1.26	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.40	67.00	7.66
SOUTH MIDDLE ROAD TS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	1.00	13.33	7.00	13.39
SOWERBY DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
SPANISH DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
ST ANDREWS TS	2.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	20.00
ST ISIDORE TS	162.00	23.02	0.00	0.00	2.00	4.70	0.00	0.00	5.00	1.22	169.00	28.95
ST LAWRENCE TS	80.00	71.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.00	71.22
ST MARYS TS	51.00	1.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.00	1.17
STAYNER TS	199.00	6.03	2.00	28.45	0.00	0.00	0.00	0.00	0.00	0.00	201.00	34.48
STEWARTVILLE TS	84.00	4.35	0.00	0.00	0.00	0.00	1.00	12.06	0.00	0.00	85.00	16.41
STRATFORD TS	170.00	1.96	0.00	0.00	0.00	0.00	0.00	0.00	3.00	1.10	173.00	3.06
STRATHROY TS	59.00	14.58	1.00	4.10	0.00	0.00	0.00	0.00	0.00	0.00	60.00	18.68
STRIKER DS	60.00	2.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.00	2.53

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
TALBOT TS DESN2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMAGAMI DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
THOROLD TS	30.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.25
TILBURY WEST DS	48.00	0.56	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	10.56
TILLSONBURG TS	170.00	2.01	2.00	19.80	0.00	0.00	0.00	0.00	0.00	0.00	172.00	21.81
TIMMINS TS	4.00	0.04	0.00	0.00	0.00	0.00	2.00	20.50	0.00	0.00	6.00	20.54
TROUT LAKE TS	87.00	2.32	0.00	0.00	0.00	0.00	2.00	10.80	0.00	0.00	89.00	13.12
VERMILION BAY DS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
VERNER DS	31.00	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.63
WALLACE TS	100.00	0.95	0.00	0.00	0.00	0.00	1.00	0.60	0.00	0.00	101.00	1.55
WALLACEBURG TS	174.00	1.71	1.00	10.00	0.00	0.00	0.00	0.00	1.00	5.16	176.00	16.86
WANSTEAD TS	186.00	3.71	1.00	10.00	1.00	2.40	0.00	0.00	0.00	0.00	188.00	16.11
WARREN DS	16.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.71
WAUBAUSHENE TS	141.00	42.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	141.00	42.86
WENDOVER DS	62.00	13.08	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	63.00	13.58
WHARNCLIFFE DS	18.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.17
WHITEFISH DS	16.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.62
WILHAVEN DS	21.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.19
WILSON TS DESN2	143.00	21.91	0.00	0.00	0.00	0.00	1.00	0.01	1.00	19.40	145.00	41.32
WINGHAM TS	130.00	1.93	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	131.00	19.93
WOLVERTON DS	61.00	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.00	1.32
WONDERLAND TS	39.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.61
WOODSTOCK TS	36.00	2.92	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	38.00	2.94

Notes on Data

- The FTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only resources directly connected to Hydro One's network are included. Resources that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.

Number and MW of Behind the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2023

The breakdown of behind-the-meter Distributed Energy Resources (BTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by transmission station as of December 31, 2023 is as follows:

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
AGUASABON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
ALLANBURG TS	21.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.18
ALLISTON TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	2.00	18.24	5.00	18.26
ALMONTE TS	38.00	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.00	0.43
ARDOCH DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
ARMITAGE TS DESN1	15.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	16.00	0.62
ARMITAGE TS DESN2	22.00	0.56	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.49	24.00	1.05
ARNPRIOR TS	40.00	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.00	0.46
AYLMER TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
BARRIE TS	1.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.20
BATTERSEA DS	8.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.09
BEAMSVILLE TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
BEAVERTON TS	30.00	0.36	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.36
BELLE RIVER TS	8.00	0.10	1.00	0.01	0.00	0.00	0.00	0.00	1.00	0.03	10.00	0.13
BELLEVILLE TS	48.00	1.22	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.90	49.00	2.12
BILBERRY CREEK TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
BIRCH TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.98	2.00	3.98
BLOOMSBURG DS	14.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.18
BRACEBRIDGE TS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
BRANT TS	16.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.13
BRANTFORD TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
BROCKVILLE TS	45.00	0.87	0.00	0.00	0.00	0.00	0.00	0.00	4.00	13.10	49.00	13.97
BROWN HILL TS	54.00	0.46	1.00	0.01	0.00	0.00	0.00	0.00	2.00	0.64	57.00	1.11
BUCHANAN TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	6.00	0.06
BURLEIGH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CALEDONIA TS	17.00	0.20	4.00	0.01	0.00	0.00	0.00	0.00	2.00	4.00	23.00	4.22
CENTRALIA TS	13.00	0.77	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	14.00	0.78
CHAPLEAU DS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.80	1.00	1.80
CHESTERVILLE TS	18.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.19
CLARABELLE TS	16.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.26
CLARENCE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CLARKE TS	16.00	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.44
CLEARWATER BAY DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
COBDEN DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
COBDEN TS	19.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07	26.00	0.20
COCHRANE WEST DS	7.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.30
COMMERCE WAY TS	7.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.50	8.00	2.71
CONSTANCE DS	5.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	6.00	0.11
CRAIG DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CRAWFORD TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.79	1.00	0.79
CROSBY TS DESN1	11.00	0.20	1.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	13.00	0.21
CROWLAND TS	7.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	1.00	5.63	8.00	5.68
CRYSTAL FALLS TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
CUMBERLAND DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
DES JOACHIMS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
DOBBIN DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
DOBBIN TS	49.00	0.47	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.50	50.00	2.97
DOUGLAS POINT TS	18.00	0.64	1.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.89
DRYDEN TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
DUART TS DESN1	9.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.31
DUNDAS TS	31.00	0.27	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.23	34.00	0.50
DUNNVILLE TS	19.00	0.31	1.00	0.02	0.00	0.00	0.00	0.00	2.00	0.02	22.00	0.35
DYMOND TS	5.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.07	7.00	3.13
EDGEWARE TS	41.00	0.87	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.80	42.00	1.67
ELMIRA TS	2.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.05
ENFIELD TS DESN 1	8.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.52	9.00	0.61
ESPANOLA TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
ETON DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
EVERETT TS	14.00	0.12	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.13
FAUQUIER DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
FERGUS TS	92.00	1.44	1.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	93.00	1.47
FOREST JURA DS	13.00	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.46
FOREST LEA DS	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.07
FRONTENAC TS	38.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.00	0.52
GALT TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
GODERICH TS	5.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	6.00	0.17
GRAND BEND EAST DS	6.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.10
GREELY DS	23.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.00	0.24
HANOVER TS	59.00	0.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.00	0.59
HARROWSMITH DS	20.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	0.16
HAVELOCK TS	31.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	1.00	4.00	32.00	4.25

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
HAWTHORNE TS	36.00	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.00	0.37
HEARST TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
HERRIDGE LAKE DS	1.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	4.00	0.08
HIGHBURY TS	12.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.22
HINCHINBROOKE DS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
HOLLAND TS	11.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.33
HOYLE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
INGERSOLL TS	24.00	1.21	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	27.00	1.24
JARVIS TS	16.00	0.48	2.00	0.01	0.00	0.00	0.00	0.00	4.00	0.03	22.00	0.52
KAPUSKASING TS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.16	3.00	0.17
KEEWATIN DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
KEITH TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.40	1.00	3.40
KENORA DS	12.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.10
KENT TS DESN1	10.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.00	0.10
KENT TS DESN2	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	3.00	0.77
KINGSTON GARDINER TS DESN1	27.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.00	0.21
KINGSTON GARDINER TS DESN2	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.00	16.80	3.00	16.81
KINGSVILLE TS	13.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.82	14.00	1.17
KIRKLAND LAKE TS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
KLEINBURG TS	43.00	0.68	1.00	0.01	0.00	0.00	0.00	0.00	3.00	4.62	47.00	5.31
LAFOREST ROAD DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
LAMBTON TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
LARCHWOOD TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	5.00	0.05
LAUZON TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.95	1.00	0.95
LAUZON TS DESN2	5.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	6.00	1.05

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
LDC OWNED STATION	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
LEAMINGTON TS DESN 1	10.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	1.00	10.00	11.00	10.30
LEAMINGTON TS DESN 2	2.00	0.51	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.82	3.00	1.33
LINDSAY TS	29.00	1.38	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	31.00	1.40
LODGEROOM DS	11.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.15
LONGLAC TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
LONGUEUIL TS	25.00	0.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.00	0.74
LONGWOOD TS	22.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	0.33
MALDEN TS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	1.00	9.20	6.00	9.25
MANITOULIN TS	24.00	0.73	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	25.00	0.74
MANOTICK DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
MARATHON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MARGACH DS	12.00	0.09	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.10
MARIONVILLE DS	6.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.14
MARTINDALE TS	15.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	18.00	0.15
MASSEY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MAZINAW DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
MEAFORD TS	59.00	0.55	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.99	60.00	3.54
MIDHURST TS DESN1	30.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	31.00	1.11
MINDEN TS	47.00	0.36	1.00	0.00	0.00	0.00	1.00	0.04	0.00	0.00	49.00	0.41
MONTEITH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MORRISBURG TS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14
MURILLO DS	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.07
MUSKOKA TS	62.00	0.98	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06	68.00	1.04
NAPANEE TS	26.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.00	0.23

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
NAVAN DS	7.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07
NEBO TS DESN1	27.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	2.00	5.25	29.00	5.59
NESTOR FALLS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NEWINGTON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NORFOLK TS	22.00	0.41	0.00	0.00	0.00	0.00	0.00	0.00	2.00	2.02	24.00	2.43
NORTHBROOK DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
ORANGEVILLE TS DESN1	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
ORANGEVILLE TS DESN2	90.00	1.03	1.00	0.01	0.00	0.00	0.00	0.00	1.00	0.05	92.00	1.09
ORILLIA TS	38.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	4.00	3.28	42.00	3.63
ORLEANS TS	20.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	21.00	1.25
OTONABEE TS DESN1	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
OTONABEE TS DESN2	48.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.00	0.60
OWEN SOUND TS	161.00	1.60	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	162.00	1.60
PALMERSTON TS	37.00	1.17	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.26	39.00	1.44
PARRY SOUND TS	38.00	0.28	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	39.00	0.29
PEMBROKE TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
PETAWAWA DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.05	3.00	3.06
PIC DS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
PICTON TS	73.00	0.72	1.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	74.00	0.80
PLEASANT TS DESN1	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
PORT ARTHUR TS #1	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
PORT HOPE TS DESN1	46.00	1.54	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.00	47.00	4.54
PUSLINCH DS	28.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.00	0.26
RAMORE TS	2.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.04
RED LAKE TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
ROCKLAND DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
ROCKLAND EAST DS	12.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.18
RUSSELL DS	6.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.05
SAM LAKE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SAPAWE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SCHREIBER WINNIPEG DS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
SEAFORTH TS	11.00	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.29
SHARBOT DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
SIDNEY TS	38.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.00	0.31
SIOUX NARROWS DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
SMITHS FALLS TS	68.00	1.05	0.00	0.00	0.00	0.00	0.00	0.00	23.00	1.44	91.00	2.48
SOUTH GLOUCESTER DS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
SOUTH MARCH TS	31.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.30
SOWERBY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SPANISH DS	2.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.17
ST ISIDORE TS	22.00	1.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	1.67
ST LAWRENCE TS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14
ST MARYS TS	7.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.39
STAYNER TS	51.00	0.63	0.00	0.00	0.00	0.00	0.00	0.00	1.00	4.00	52.00	4.63
STEWARTVILLE TS	18.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.14
STRATFORD TS	16.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	17.00	0.62
STRATHROY TS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
STRIKER DS	4.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.08
TEMAGAMI DS	0.00	0.00	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
THOROLD TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
TILBURY WEST DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
TILLSONBURG TS	23.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.86	28.00	1.17
TIMMINS TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.57	1.00	1.57
TROUT LAKE TS	25.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	28.00	0.28	53.00	0.49
VERNER DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
WALLACE TS	23.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.09	32.00	0.23
WALLACEBURG TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
WANSTEAD TS	4.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.07
WARREN DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
WAUBAUSHENE TS	30.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.21
WENDOVER DS	16.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.39
WHARNCLIFFE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
WHITEFISH DS	10.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06	16.00	0.14
WILHAVEN DS	9.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.17
WILSON TS DESN2	28.00	15.96	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	29.00	15.96
WINGHAM TS	19.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.71
WOLVERTON DS	13.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.24
WONDERLAND TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
WOODSTOCK TS	15.00	1.13	0.00	0.00	1.00	0.01	0.00	0.00	1.00	1.00	17.00	2.14

Notes on Data

- The BTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only DERs directly connected to Hydro One's network are included. DERs that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.
- The list only consists of BTM DER Resources that Hydro One has records of. There may be BTM DERs that are utilized by customers for their own purposes (e.g. backup diesel generation in mines). As customers have no obligation to inform Hydro One of these installations, these installations are neither tracked nor included in this list.

Number and MW of Front of the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2024

The breakdown of front-of-the-meter Distributed Energy Resources (FTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by station as of December 31, 2024 is as follows:

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
AGIMAK DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
AGUASABON DS	6.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.09
ALLANBURG TS	70.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	1.40
ALLISTON TS	41.00	1.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.00	1.06
ALMONTE TS	112.00	21.82	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	113.00	21.83
ARDOCH DS	13.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.12
ARMITAGE TS DESN1	73.00	7.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.00	7.24
ARMITAGE TS DESN2	93.00	1.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	93.00	1.31
ARNPRIOR TS	119.00	22.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	119.00	22.23
AYLMER TS	50.00	2.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00	2.48
BALLINAFAD MS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
BARWICK TS	103.00	25.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.00	25.99
BATTERSEA DS	70.00	1.24	0.00	0.00	1.00	0.25	0.00	0.00	2.00	1.00	73.00	2.49
BEAMSVILLE TS	7.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07
BEARDMORE DS #2	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.00	0.00	0.00	1.00	6.00
BEAVERTON TS	300.00	57.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300.00	57.72
BELLE RIVER TS	167.00	2.87	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	168.00	12.87
BELLEVILLE TS	205.00	52.76	0.00	0.00	1.00	0.25	0.00	0.00	1.00	0.50	207.00	53.51
BILBERRY CREEK TS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
BLOOMSBURG DS	17.00	13.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	13.24
BRACEBRIDGE TS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
BRANT TS	107.00	9.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	9.70
BRANTFORD TS	11.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	1.00	8.10	12.00	8.21
BROCKVILLE TS	219.00	32.53	0.00	0.00	0.00	0.00	0.00	0.00	2.00	10.00	221.00	42.53
BROWN HILL TS	212.00	32.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	212.00	32.97
BUCHANAN TS	14.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.34
BUNTING TS	0.00	0.00	0.00	0.00	0.00	0.00	2.00	4.00	0.00	0.00	2.00	4.00
BURLEIGH DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CALEDONIA TS	31.00	20.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	20.95
CALSTOCK DS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
CAMPBELL TS DESN2	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CENTRALIA TS	145.00	5.16	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.50	147.00	5.66
CHESTERVILLE TS	100.00	21.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	21.35
CLARABELLE TS	79.00	2.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.00	2.51
CLARENCE DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
CLARKE TS	63.00	1.38	0.00	0.00	1.00	0.30	0.00	0.00	3.00	0.75	67.00	2.43
CLEARWATER BAY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
COBDEN DS	37.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.00	0.36
COBDEN TS	137.00	4.45	0.00	0.00	1.00	0.50	0.00	0.00	0.00	0.00	138.00	4.95
COCHRANE WEST DS	19.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.19
COMMERCE WAY TS	94.00	2.90	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	95.00	20.90
CONSTANCE DS	97.00	1.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	97.00	1.44
CRAIG DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CRILLY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CROSBY TS	5.00	40.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	40.01
CROSBY TS DESN1	49.00	21.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	21.89

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
CROWLAND TS	14.00	0.27	1.00	9.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	9.27
CRYSTAL FALLS TS	43.00	5.62	0.00	0.00	0.00	0.00	3.00	11.50	0.00	0.00	46.00	17.12
CUMBERLAND DS	21.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.39
DEEP RIVER DS	15.00	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.28
DES JOACHIMS DS	3.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.26
DOBBIN DS	24.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.00	0.34
DOBBIN TS	189.00	14.12	1.00	10.00	0.00	0.00	0.00	0.00	1.00	0.10	191.00	24.22
DOUGLAS POINT TS	117.00	2.10	3.00	11.05	0.00	0.00	0.00	0.00	0.00	0.00	120.00	13.15
DRYDEN TS	31.00	10.28	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.38	33.00	10.66
DUART TS DESN1	103.00	10.91	1.00	10.00	0.00	0.00	0.00	0.00	1.00	0.25	105.00	21.16
DUNDAS TS	210.00	4.89	0.00	0.00	0.00	0.00	0.00	0.00	2.00	8.49	212.00	13.38
DUNNVILLE TS	23.00	0.67	2.00	9.90	0.00	0.00	0.00	0.00	2.00	10.42	27.00	20.99
DYMOND TS	59.00	9.92	0.00	0.00	0.00	0.00	1.00	9.50	0.00	0.00	60.00	19.42
EAR FALLS TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
EDGEWARE TS	107.00	3.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	3.77
ELLIOT LAKE TS	14.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.20
ELMIRA TS	24.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.25	25.00	0.60
ENFIELD TS DESN 1	92.00	1.56	4.00	35.85	0.00	0.00	0.00	0.00	0.00	0.00	96.00	37.41
ESPANOLA TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
ETON DS	29.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.00	0.33
EVERETT TS	106.00	1.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	106.00	1.10
FALLOWFIELD DS	0.00	0.00	0.00	0.00	1.00	5.55	0.00	0.00	0.00	0.00	1.00	5.55
FAUQUIER DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
FERGUS TS	198.00	3.01	3.00	41.20	0.00	0.00	0.00	0.00	1.00	0.14	202.00	44.35
FOREST JURA DS	98.00	1.38	2.00	16.50	0.00	0.00	0.00	0.00	0.00	0.00	100.00	17.88

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
FOREST LEA DS	12.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.12
FRONTENAC TS	130.00	2.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	130.00	2.31
GALT TS	16.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.15
GODERICH TS	79.00	1.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.00	1.15
GRAND BEND EAST DS	42.00	1.01	1.00	0.80	2.00	1.00	0.00	0.00	0.00	0.00	45.00	2.81
GREELY DS	67.00	1.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	1.61
HANOVER TS	362.00	8.88	1.00	22.17	0.00	0.00	2.00	0.28	3.00	0.75	368.00	32.08
HARROWSMITH DS	139.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	139.00	1.28
HAVELOCK TS	242.00	12.11	0.00	0.00	0.00	0.00	1.00	18.00	0.00	0.00	243.00	30.11
HAWTHORNE TS	82.00	11.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.00	11.75
HEARST TS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
HERRIDGE LAKE DS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
HIGHBURY TS	35.00	7.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.00	7.49
HINCHINBROOKE DS	39.00	0.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.58
HOLLAND TS	76.00	2.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	76.00	2.45
INGERSOLL TS	133.00	21.83	0.00	0.00	0.00	0.00	0.00	0.00	4.00	1.00	137.00	22.83
INNISFIL MS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
IROQUOIS FALLS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
JARVIS TS	33.00	4.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	4.21
KAPUSKASING TS	64.00	8.64	0.00	0.00	0.00	0.00	4.00	22.00	0.00	0.00	68.00	30.64
KEITH TS DESN1	6.00	20.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	20.04
KENORA DS	15.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.15
KENT TS DESN1	178.00	2.63	3.00	30.00	0.00	0.00	0.00	0.00	0.00	0.00	181.00	32.63
KENT TS DESN2	125.00	1.25	2.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	127.00	21.25
KINGSTON GARDINER TS DESN1	147.00	42.35	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	148.00	52.35

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
KINGSTON GARDINER TS DESN2	34.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	0.62
KINGSVILLE TS	191.00	3.00	3.00	25.80	0.00	0.00	0.00	0.00	1.00	12.00	195.00	40.80
KIRKLAND LAKE TS	34.00	8.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	8.51
KLEINBURG TS	172.00	3.63	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.23	173.00	6.86
LAFOREST ROAD DS	1.00	0.01	0.00	0.00	0.00	0.00	1.00	14.00	0.00	0.00	2.00	14.01
LAMBTON TS	42.00	40.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.00	40.61
LARCHWOOD TS	34.00	0.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	0.86
LAUZON TS DESN1	3.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.23
LAUZON TS DESN2	149.00	2.60	2.00	20.00	1.00	0.25	0.00	0.00	0.00	0.00	152.00	22.85
LDC Owned Station	11.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.11
LEAMINGTON TS DESN 1	163.00	3.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	163.00	3.49
LEAMINGTON TS DESN 2	42.00	0.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.00	0.85
LINDSAY TS	232.00	45.60	0.00	0.00	1.00	0.50	1.00	0.50	1.00	0.34	235.00	46.94
LODGEROOM DS	67.00	1.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	1.10
LONGLAC TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
LONGUEUIL TS	144.00	51.57	1.00	0.01	3.00	0.46	0.00	0.00	0.00	0.00	148.00	52.04
LONGWOOD TS	158.00	3.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	158.00	3.33
MALDEN TS	109.00	12.39	3.00	29.80	0.00	0.00	0.00	0.00	0.00	0.00	112.00	42.19
MANITOULIN TS	101.00	0.95	2.00	5.60	0.00	0.00	0.00	0.00	0.00	0.00	103.00	6.55
MANITOUWADGE DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
MANITOUWADGE TS	3.00	0.03	0.00	0.00	2.00	13.00	0.00	0.00	0.00	0.00	5.00	13.03
MANOTICK DS	18.00	0.46	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	19.00	0.96
MARATHON DS	17.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.13
MARGACH DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
MARIONVILLE DS	64.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.75	66.00	1.37

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
MARTINDALE TS	47.00	10.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.00	10.91
MASSEY DS	13.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.13
MATTAWA DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
MAZINAW DS	12.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.10
MEAFORD TS	64.00	1.16	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	65.00	19.16
MIDHURST TS DESN1	242.00	37.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	242.00	37.89
MINDEN TS	86.00	2.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.00	2.28
MONTEITH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MORRISBURG TS	115.00	20.73	1.00	30.00	0.00	0.00	0.00	0.00	0.00	0.00	116.00	50.73
MOUNTAIN CHUTE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MURILLO DS	100.00	1.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	1.21
MUSKOKA TS	222.00	29.07	0.00	0.00	0.00	0.00	1.00	5.00	0.00	0.00	223.00	34.07
NAKINA DS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.50	1.00	1.50
NAPANEE TS	231.00	60.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	231.00	60.35
NAVAN DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
NEBO TS DESN1	90.00	1.06	0.00	0.00	1.00	3.20	0.00	0.00	0.00	0.00	91.00	4.26
NESTOR FALLS DS	13.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.12
NEWINGTON DS	9.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.10
NIPIGON DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
NORFOLK TS	131.00	11.13	2.00	19.90	0.00	0.00	0.00	0.00	1.00	8.50	134.00	39.53
NORTH BAY TS	1.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.08
NORTH SHORE DS	17.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.16
NORTHBROOK DS	31.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.52
ORANGEVILLE TS DESN1	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
ORANGEVILLE TS DESN2	361.00	5.44	5.00	44.23	0.00	0.00	0.00	0.00	0.00	0.00	366.00	49.67

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
ORILLIA TS	183.00	31.84	0.00	0.00	0.00	0.00	1.00	1.65	1.00	1.06	185.00	34.55
ORLEANS TS	71.00	3.10	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	72.00	4.10
OTONABEE TS DESN1	17.00	2.34	0.00	0.00	1.00	1.60	0.00	0.00	0.00	0.00	18.00	3.94
OTONABEE TS DESN2	235.00	9.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	235.00	9.24
OWEN SOUND TS	370.00	10.62	0.00	0.00	1.00	0.10	0.00	0.00	0.00	0.00	371.00	10.72
PALMERSTON TS	256.00	4.76	1.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	257.00	5.26
PARRY SOUND TS	57.00	3.63	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.00	58.00	5.63
PEMBROKE TS	33.00	0.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	0.59
PETAWAWA DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
PIC DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
PICTON TS	218.00	28.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	218.00	28.78
PLEASANT TS DESN1	23.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.00	0.31
PORT ARTHUR TS #1	30.00	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.28
PORT COLBORNE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
PORT HOPE TS DESN1	237.00	34.97	0.00	0.00	1.00	0.01	0.00	0.00	0.00	0.00	238.00	34.98
PUSLINCH DS	96.00	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.00	1.60
RAMORE TS	12.00	8.11	0.00	0.00	0.00	0.00	1.00	0.52	0.00	0.00	13.00	8.63
RED LAKE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
RED ROCK DS	29.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.00	1.28
ROCKLAND DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
ROCKLAND EAST DS	14.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.14
RUSSELL DS	7.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.13
SCHREIBER WINNIPG DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
SEAFORTH TS	102.00	2.61	1.00	15.00	0.00	0.00	0.00	0.00	0.00	0.00	103.00	17.61
SHABAQUA DS	9.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.09

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
SHARBOT DS	22.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	0.19
SIDNEY TS	246.00	4.04	0.00	0.00	0.00	0.00	1.00	10.00	0.00	0.00	247.00	14.04
SIOUX NARROWS DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
SMITHS FALLS TS	256.00	83.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	256.00	83.34
SOUTH GLOUCESTER DS	13.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.16
SOUTH MARCH TS	66.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.40	67.00	7.68
SOUTH MIDDLE ROAD TS	9.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	1.00	13.33	10.00	13.42
SOWERBY DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
SPANISH DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
ST ISIDORE TS	162.00	23.10	0.00	0.00	2.00	4.70	0.00	0.00	5.00	1.22	169.00	29.03
ST LAWRENCE TS	80.00	81.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.00	81.25
ST MARYS TS	51.00	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.00	1.19
STAYNER TS	199.00	6.12	2.00	28.45	0.00	0.00	0.00	0.00	0.00	0.00	201.00	34.57
STEWARTVILLE TS	83.00	4.35	0.00	0.00	0.00	0.00	1.00	10.70	0.00	0.00	84.00	15.05
STRATFORD TS	170.00	1.98	0.00	0.00	0.00	0.00	0.00	0.00	3.00	1.10	173.00	3.08
STRATHROY TS	59.00	14.58	1.00	4.10	0.00	0.00	0.00	0.00	0.00	0.00	60.00	18.68
STRIKER DS	60.00	2.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.00	2.54
TEMAGAMI DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
THOROLD TS	30.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.26
TILBURY WEST DS	48.00	0.57	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	10.57
TILLSONBURG TS	165.00	2.01	2.00	19.80	0.00	0.00	0.00	0.00	0.00	0.00	167.00	21.81
TIMMINS TS	4.00	0.04	0.00	0.00	0.00	0.00	2.00	20.50	0.00	0.00	6.00	20.54
TROUT LAKE TS	87.00	2.35	0.00	0.00	0.00	0.00	2.00	10.80	0.00	0.00	89.00	13.15
VERMILION BAY DS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
VERNER DS	31.00	0.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.64

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
WALLACE TS	100.00	0.97	0.00	0.00	0.00	0.00	1.00	0.60	0.00	0.00	101.00	1.57
WALLACEBURG TS	175.00	1.72	1.00	10.00	0.00	0.00	0.00	0.00	1.00	5.16	177.00	16.88
WANSTEAD TS	185.00	3.48	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	186.00	13.48
WARREN DS	16.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.71
WAUBAUSHENE TS	143.00	43.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	143.00	43.69
WENDOVER DS	62.00	13.11	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	63.00	13.61
WHARNCLIFFE DS	18.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.18
WHITEFISH DS	16.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.62
WILHAVEN DS	21.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.19
WILSON TS DESN2	142.00	21.96	0.00	0.00	0.00	0.00	1.00	0.01	1.00	19.40	144.00	41.37
WINGHAM TS	130.00	1.98	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	131.00	19.98
WOLVERTON DS	61.00	1.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.00	1.35
WONDERLAND TS	39.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.61
WOODSTOCK TS	36.00	2.90	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	37.00	2.91

Notes on Data

- The FTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only resources directly connected to Hydro One's network are included. Resources that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.

Number and MW of Behind the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2024

The breakdown of behind-the-meter Distributed Energy Resources (BTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by transmission station as of December 31, 2024 is as follows:

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
AGUASABON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
ALLANBURG TS	22.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	0.19
ALLISTON TS	5.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	2.00	18.24	7.00	18.36
ALMONTE TS	57.00	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.00	0.63
ARDOCH DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
ARMITAGE TS DESN1	24.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	25.00	0.68
ARMITAGE TS DESN2	31.00	0.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.86
ARNPRIOR TS	52.00	0.56	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	55.00	0.59
AWENDA DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
AYLMER TS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	7.00	0.07
BARRIE TS	1.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.20
BATTERSEA DS	12.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.12
BEAMSVILLE TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
BEAVERTON TS	48.00	0.52	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	0.53
BELLE RIVER TS	10.00	0.12	1.00	0.01	0.00	0.00	0.00	0.00	1.00	0.03	12.00	0.15
BELLEVILLE TS	59.00	1.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.00	1.50
BILBERRY CREEK TS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
BIRCH TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.98	2.00	3.98
BLOOMSBURG DS	17.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.20
BRACEBRIDGE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
BRANT TS	20.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	22.00	0.19

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
BRANTFORD TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
BROCKVILLE TS	61.00	1.86	0.00	0.00	0.00	0.00	0.00	0.00	3.00	3.60	64.00	5.46
BROWN HILL TS	70.00	0.60	2.00	0.01	0.00	0.00	0.00	0.00	2.00	0.64	74.00	1.25
BUCHANAN TS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	3.00	14.27	9.00	14.33
BURLEIGH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CALEDONIA TS	20.00	0.23	4.00	0.01	0.00	0.00	0.00	0.00	2.00	4.00	26.00	4.24
CENTRALIA TS	18.00	1.28	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04	22.00	1.32
CHAPLEAU DS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.80	1.00	1.80
CHESTERVILLE TS	28.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.00	0.33
CLARABELLE TS	19.00	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.29
CLARENCE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CLARKE TS	19.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	4.00	10.46	23.00	10.91
CLEARWATER BAY DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
COBDEN DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
COBDEN TS	27.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.12	39.00	0.32
COCHRANE WEST DS	7.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.30
COMMERCE WAY TS	17.00	0.65	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.50	18.00	3.15
CONSTANCE DS	8.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	9.00	0.14
CRAIG DS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
CRAWFORD TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.79	1.00	0.79
CROSBY TS DESN1	14.00	0.23	1.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04	19.00	0.27
CROWLAND TS	8.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.06
CRYSTAL FALLS TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
CUMBERLAND DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
DES JOACHIMS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	2.00	0.02

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
DOBBIN DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
DOBBIN TS	64.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.50	65.00	3.10
DOUGLAS POINT TS	32.00	0.87	1.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	33.00	1.11
DRYDEN TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
DUART TS DESN1	12.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.34
DUNDAS TS	41.00	0.73	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.23	44.00	0.96
DUNNVILLE TS	22.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.04	25.00	0.38
DYMOND TS	5.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.07	7.00	3.13
EDGEWARE TS	49.00	0.93	0.00	0.00	0.00	0.00	0.00	0.00	3.00	11.10	52.00	12.03
ELMIRA TS	2.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.30	3.00	2.35
ENFIELD TS DESN 1	12.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.52	13.00	0.65
ESPANOLA TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
ETON DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
EVERETT TS	18.00	0.34	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.35
FAUQUIER DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
FERGUS TS	106.00	1.59	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.04	108.00	1.63
FOREST JURA DS	18.00	0.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.56
FOREST LEA DS	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.07
FRONTENAC TS	48.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.00	0.61
GALT TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
GODERICH TS	5.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	6.00	0.17
GRAND BEND EAST DS	7.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.11
GREELY DS	32.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.00	0.31
HANOVER TS	75.00	0.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	75.00	0.86
HARROWSMITH DS	23.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.00	0.19

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
HAVELOCK TS	40.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	7.00	4.06	47.00	4.39
HAWTHORNE TS	40.00	0.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.00	0.41
HEARST TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
HERRIDGE LAKE DS	2.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	5.00	0.18
HIGHBURY TS	12.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	2.00	6.00	14.00	6.21
HINCHINBROOKE DS	5.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05	10.00	0.08
HOLLAND TS	14.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.36
HOYLE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
INGERSOLL TS	30.00	1.37	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.14	44.00	1.51
JARVIS TS	18.00	0.49	2.00	0.01	0.00	0.00	0.00	0.00	4.00	0.03	24.00	0.53
KAPUSKASING TS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.16	3.00	0.17
KEEWATIN DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
KEITH TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.40	1.00	3.40
KENORA DS	16.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.13
KENT TS DESN1	15.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	1.00	5.00	16.00	5.36
KENT TS DESN2	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	3.00	2.40	6.00	2.43
KINGSTON GARDINER TS DESN1	52.00	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.00	0.44
KINGSTON GARDINER TS DESN2	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.00	16.80	3.00	16.81
KINGSVILLE TS	16.00	0.37	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.82	17.00	1.19
KIRKLAND LAKE TS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
KLEINBURG TS	56.00	0.80	1.00	0.01	0.00	0.00	0.00	0.00	4.00	4.63	61.00	5.44
LAFOREST ROAD DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
LAMBTON TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
LARCHWOOD TS	7.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04	11.00	0.11
LAUZON TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.95	1.00	0.95

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
LAUZON TS DESN2	6.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	7.00	1.06
LDC Owned Station	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
LEAMINGTON TS DESN 1	10.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	1.00	10.00	11.00	10.30
LEAMINGTON TS DESN 2	2.00	0.51	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.82	3.00	1.33
LINDSAY TS	35.00	1.44	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04	39.00	1.48
LODGEROOM DS	14.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.17
LONGLAC TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
LONGUEUIL TS	31.00	0.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.79
LONGWOOD TS	34.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	0.45
MALDEN TS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	1.00	9.20	7.00	9.26
MANITOULIN TS	30.00	0.78	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.79
MANOTICK DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
MARATHON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MARGACH DS	14.00	0.11	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.12
MARIONVILLE DS	11.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.18
MARTINDALE TS	23.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07	30.00	0.27
MASSEY DS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
MATTAWA DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	3.00	0.03
MAZINAW DS	72.00	0.67	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.99	73.00	3.66
MEAFORD TS	40.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	41.00	1.20
MIDHURST TS DESN1	58.00	0.46	1.00	0.00	0.00	0.00	1.00	0.04	0.00	0.00	60.00	0.50
MINAKI DS	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00
MINDEN TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	25.00	0.25	26.00	0.26
MONTEITH DS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14
MORRISBURG TS	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.07

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
MURILLO DS	78.00	1.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	78.00	1.13
MUSKOKA TS	36.00	0.32	0.00	0.00	0.00	0.00	0.00	0.00	27.00	0.27	63.00	0.59
NAPANEE TS	7.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07
NAVAN DS	33.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	2.00	5.25	35.00	5.64
NEBO TS DESN1	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NESTOR FALLS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NEWINGTON DS	23.00	0.42	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	24.00	1.17
NORFOLK TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NORTHBROOK DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
ORANGEVILLE TS DESN1	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	4.00	0.04
ORANGEVILLE TS DESN2	114.00	1.44	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	115.00	1.45
ORILLIA TS	55.00	0.51	0.00	0.00	0.00	0.00	0.00	0.00	4.00	3.28	59.00	3.79
ORLEANS TS	27.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.00	0.31
OTONABEE TS DESN1	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	11.00	0.10
OTONABEE TS DESN2	60.00	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.00	0.88
OWEN SOUND TS	197.00	1.99	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	198.00	1.99
PALMERSTON TS	54.00	2.16	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.13	55.00	2.29
PARRY SOUND TS	39.00	0.29	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	40.00	0.30
PEMBROKE TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
PETAWAWA DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.05	3.00	3.06
PIC DS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
PICTON TS	86.00	0.84	1.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	87.00	0.92
PLEASANT TS DESN1	4.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.95	5.00	0.97
PORT ARTHUR TS #1	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
PORT HOPE TS DESN1	52.00	2.07	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.00	53.00	5.07

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
PUSLINCH DS	32.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.00	0.30
RAMORE TS	3.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.19
RED LAKE TS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
ROCKLAND DS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
ROCKLAND EAST DS	13.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.19
RUSSELL DS	7.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.06
SAM LAKE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SAPAWE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SCHREIBER WINNIPG DS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
SEAFORTH TS	14.00	0.81	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	15.00	0.82
SHARBOT DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	5.00	0.05
SIDNEY TS	43.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.00	0.35
SIOUX NARROWS DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
SMITHS FALLS TS	87.00	1.44	0.00	0.00	0.00	0.00	0.00	0.00	43.00	1.64	130.00	3.08
SOUTH GLOUCESTER DS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
SOUTH MARCH TS	33.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	0.31
SOWERBY DS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
SPANISH DS	3.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.18
ST ISIDORE TS	28.00	1.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.00	1.84
ST LAWRENCE TS	21.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.19
ST MARYS TS	8.00	0.43	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.76	9.00	2.19
STAYNER TS	65.00	0.76	0.00	0.00	0.00	0.00	0.00	0.00	3.00	11.16	68.00	11.92
STEWARTVILLE TS	22.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	23.00	0.18
STRATFORD TS	25.00	1.02	0.00	0.00	0.00	0.00	0.00	0.00	3.00	4.51	28.00	5.52
STRATHROY TS	4.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.22

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
STRIKER DS	4.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.08
TEMAGAMI DS	0.00	0.00	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
THOROLD TS	5.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.09
TILBURY WEST DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
TILLSONBURG TS	30.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	25.00	1.06	55.00	1.66
TIMMINS TS	1.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.57	2.00	1.65
TROUT LAKE TS	28.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	70.00	0.70	98.00	0.94
VERMILION BAY DS	1.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.09
VERNER DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
WALLACE TS	30.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	40.00	0.40	70.00	0.62
WALLACEBURG TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
WANSTEAD TS	4.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.07
WARREN DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
WAUBAUSHENE TS	44.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.00	0.34
WENDOVER DS	17.00	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.40
WHARNCLIFFE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	2.00	0.02
WHITEFISH DS	13.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08	21.00	0.19
WILHAVEN DS	10.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.00	0.18
WILSON TS DESN2	33.00	16.00	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	34.00	16.01
WINGHAM TS	20.00	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	0.72
WOLVERTON DS	15.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	18.00	0.27
WONDERLAND TS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
WOODSTOCK TS	23.00	1.20	0.00	0.00	0.00	0.00	0.00	0.00	2.00	1.01	25.00	2.21

Notes on Data

- The BTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only DERs directly connected to Hydro One's network are included. DERs that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.
- The list only consists of BTM DER Resources that Hydro One has records of. There may be BTM DERs that are utilized by customers for their own purposes (e.g. backup diesel generation in mines). As customers have no obligation to inform Hydro One of these installations, these installations are neither tracked nor included in this list.

Number and MW of Front of the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2025

The breakdown of front-of-the-meter Distributed Energy Resources (FTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by transmission connected station as of December 31, 2025, is as follows:

*Ct=Count, Cap=Capacity

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
AGIMAK DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
AGUASABON DS	6	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.09
ALLANBURG TS	70	1.40	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	70	1.40
ALLISTON TS	41	1.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	41	1.06
ALMONTE TS	112	21.82	1	0.01	0	0.00	0	0.00	0	0.00	1	5.00	114	26.83
ARDOCH DS	13	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.12
ARMITAGE TS DESN1	73	7.24	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	73	7.24
ARMITAGE TS DESN2	93	1.31	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	93	1.31
ARNPRIOR TS	119	22.23	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	119	22.23
AYLMER TS	50	2.48	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	50	2.48
BALLINAFAD MS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
BARWICK TS	103	25.99	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	103	25.99
BATTERSEA DS	70	1.24	0	0.00	1	0.25	2	1.00	0	0.00	0	0.00	73	2.49
BEAMSVILLE TS	7	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.07
BEARDMORE DS #2	0	0.00	0	0.00	0	0.00	0	0.00	1	6.00	0	0.00	1	6.00
BEAVERTON TS	300	57.72	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	300	57.72
BELLE RIVER TS	167	2.87	1	10.00	0	0.00	0	0.00	0	0.00	0	0.00	168	12.87

Witness: Peter Faltaous

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
BELLEVILLE TS	205	52.76	0	0.00	1	0.25	1	0.50	0	0.00	0	0.00	207	53.51
BILBERRY CREEK TS	4	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.03
BLOOMSBURG DS	17	13.24	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	13.24
BRACEBRIDGE TS	15	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.14
BRANT TS	107	9.70	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	107	9.70
BRANTFORD TS	11	0.11	0	0.00	0	0.00	0	0.00	0	0.00	1	8.10	12	8.21
BROCKVILLE TS	219	32.53	0	0.00	0	0.00	1	0.50	0	0.00	1	9.50	221	42.53
BROWN HILL TS	212	32.97	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	212	32.97
BUCHANAN TS	14	0.34	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	14	0.34
BUNTING TS	0	0.00	0	0.00	0	0.00	0	0.00	2	4.00	0	0.00	2	4.00
BURLEIGH DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
CALEDONIA TS	31	20.95	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	31	20.95
CALSTOCK DS	8	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.08
CAMPBELL TS DESN2	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
CENTRALIA TS	145	5.16	0	0.00	0	0.00	2	0.50	0	0.00	0	0.00	147	5.66
CHESTERVILLE TS	100	21.35	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	100	21.35
CLARABELLE TS	79	2.51	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	79	2.51
CLARENCE DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
CLARKE TS	63	1.38	0	0.00	1	0.30	3	0.75	0	0.00	0	0.00	67	2.43
CLEARWATER BAY DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
COBDEN DS	37	0.36	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	37	0.36

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
COBDEN TS	137	4.45	0	0.00	1	0.50	0	0.00	0	0.00	0	0.00	138	4.95
COCHRANE WEST DS	19	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	19	0.19
COMMERCE WAY TS	94	2.90	1	18.00	0	0.00	0	0.00	0	0.00	0	0.00	95	20.90
CONSTANCE DS	97	1.44	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	97	1.44
CRAIG DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
CRILLY DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
CROSBY TS	5	40.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	40.01
CROSBY TS DESN1	49	21.89	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	49	21.89
CROWLAND TS	14	0.27	1	9.00	0	0.00	0	0.00	0	0.00	0	0.00	15	9.27
CRYSTAL FALLS TS	43	5.62	0	0.00	0	0.00	0	0.00	3	11.50	0	0.00	46	17.12
CUMBERLAND DS	21	0.39	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	21	0.39
DEEP RIVER DS	15	0.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.28
DES JOACHIMS DS	3	0.26	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.26
DOBBIN DS	24	0.34	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	24	0.34
DOBBIN TS	189	14.12	1	10.00	0	0.00	1	0.10	0	0.00	0	0.00	191	24.22
DOUGLAS POINT TS	117	2.10	3	11.05	0	0.00	0	0.00	0	0.00	0	0.00	120	13.15
DRYDEN TS	31	10.28	0	0.00	0	0.00	0	0.00	0	0.00	2	0.38	33	10.66
DUART TS DESN1	103	10.91	1	10.00	0	0.00	1	0.25	0	0.00	0	0.00	105	21.16
DUNDAS TS	210	4.89	0	0.00	0	0.00	0	0.00	0	0.00	2	8.49	212	13.38
DUNNVILLE TS	23	0.67	2	9.90	0	0.00	0	0.00	0	0.00	2	10.42	27	20.99

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
DYMOND TS	59	9.92	0	0.00	0	0.00	0	0.00	1	9.50	0	0.00	60	19.42
EAR FALLS TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
EDGEWARE TS	107	3.77	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	107	3.77
ELLIOT LAKE TS	14	0.20	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	14	0.20
ELMIRA TS	24	0.35	0	0.00	0	0.00	1	0.25	0	0.00	0	0.00	25	0.60
ENFIELD TS DESN 1	92	1.56	4	35.85	0	0.00	0	0.00	0	0.00	0	0.00	96	37.41
ESPANOLA TS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
ETON DS	29	0.33	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	29	0.33
EVERETT TS	106	1.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	106	1.10
FALLOWFIELD DS	0	0.00	0	0.00	1	5.55	0	0.00	0	0.00	0	0.00	1	5.55
FAUQUIER DS	6	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.06
FERGUS TS	198	3.01	3	41.20	0	0.00	1	0.14	0	0.00	0	0.00	202	44.35
FOREST JURA DS	98	1.38	2	16.50	0	0.00	0	0.00	0	0.00	0	0.00	100	17.88
FOREST LEA DS	12	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.12
FRONTENAC TS	130	2.31	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	130	2.31
GALT TS	16	0.15	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	16	0.15
GODERICH TS	79	1.15	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	79	1.15
GRAND BEND EAST DS	42	1.01	1	0.80	2	1.00	0	0.00	0	0.00	0	0.00	45	2.81
GREELY DS	67	1.61	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	67	1.61
HANOVER TS	362	8.88	1	22.17	0	0.00	3	0.75	2	0.28	0	0.00	368	32.08
HARROWSMITH DS	139	1.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	139	1.28

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
HAVELOCK TS	242	12.11	0	0.00	0	0.00	0	0.00	1	18.00	0	0.00	243	30.11
HAWTHORNE TS	82	11.75	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	82	11.75
HEARST TS	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05
HERRIDGE LAKE DS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
HIGHBURY TS	35	7.49	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	35	7.49
HINCHINBROOK E DS	39	0.58	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	39	0.58
HOLLAND TS	76	2.45	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	76	2.45
INGERSOLL TS	133	21.83	0	0.00	0	0.00	3	0.75	0	0.00	1	0.25	137	22.83
Innisfil MS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
IROQUOIS FALLS DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
JARVIS TS	33	4.21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	33	4.21
KAPUSKASING TS	64	8.64	0	0.00	0	0.00	0	0.00	4	22.00	0	0.00	68	30.64
KEITH TS DESN1	6	20.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	20.04
KENORA DS	15	0.15	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.15
KENT TS DESN1	178	2.63	3	30.00	0	0.00	0	0.00	0	0.00	0	0.00	181	32.63
KENT TS DESN2	125	1.25	2	20.00	0	0.00	0	0.00	0	0.00	0	0.00	127	21.25
KINGSTON GARDINER TS DESN1	147	42.35	1	10.00	0	0.00	0	0.00	0	0.00	0	0.00	148	52.35
KINGSTON GARDINER TS DESN2	34	0.62	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	34	0.62
KINGSVILLE TS	191	3.00	3	25.80	0	0.00	0	0.00	0	0.00	1	12.00	195	40.80

Witness: Peter Faltaous

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
KIRKLAND LAKE TS	34	8.51	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	34	8.51
KLEINBURG TS	172	3.63	0	0.00	0	0.00	0	0.00	0	0.00	1	3.23	173	6.86
LAFOREST ROAD DS	1	0.01	0	0.00	0	0.00	0	0.00	1	14.00	0	0.00	2	14.01
LAMBTON TS	42	40.61	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	42	40.61
LARCHWOOD TS	34	0.86	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	34	0.86
LAUZON TS DESN1	3	0.23	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.23
LAUZON TS DESN2	149	2.60	2	20.00	1	0.25	0	0.00	0	0.00	0	0.00	152	22.85
LDC Owned Station	11	0.11	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.11
LEAMINGTON TS DESN 1	163	3.49	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	163	3.49
LEAMINGTON TS DESN 2	42	0.85	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	42	0.85
LINDSAY TS	232	45.60	0	0.00	1	0.50	0	0.00	1	0.50	1	0.34	235	46.94
LODGEROOM DS	67	1.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	67	1.10
LONGLAC TS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
LONGUEUIL TS	144	51.57	1	0.01	3	0.46	0	0.00	0	0.00	0	0.00	148	52.04
LONGWOOD TS	158	3.33	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	158	3.33
MALDEN TS	109	12.39	3	29.80	0	0.00	0	0.00	0	0.00	0	0.00	112	42.19
MANITOULIN TS	101	0.95	2	5.60	0	0.00	0	0.00	0	0.00	0	0.00	103	6.55
MANITOUWADGE DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
MANITOUWADGE TS	3	0.03	0	0.00	2	13.00	0	0.00	0	0.00	0	0.00	5	13.03

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
MANOTICK DS	18	0.46	0	0.00	0	0.00	1	0.50	0	0.00	0	0.00	19	0.96
MARATHON DS	17	0.13	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	0.13
MARGACH DS	11	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.10
MARIONVILLE DS	64	0.62	0	0.00	0	0.00	1	0.25	0	0.00	1	0.50	66	1.37
MARTINDALE TS	47	10.91	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	47	10.91
MASSEY DS	13	0.13	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.13
MATTAWA DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
MAZINAW DS	12	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.10
MEAFORD TS	64	1.16	1	18.00	0	0.00	0	0.00	0	0.00	0	0.00	65	19.16
MIDHURST TS DESN1	242	37.89	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	242	37.89
MINDEN TS	86	2.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	86	2.28
MONTEITH DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
MORRISBURG TS	115	20.73	1	30.00	0	0.00	0	0.00	0	0.00	0	0.00	116	50.73
MOUNTAIN CHUTE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
MURILLO DS	100	1.21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	100	1.21
MUSKOKA TS	222	29.07	0	0.00	0	0.00	0	0.00	1	5.00	0	0.00	223	34.07
NAKINA DS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	1.50	1	1.50
NAPANEE TS	231	60.35	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	231	60.35
NAVAN DS	11	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.10
NEBO TS DESN1	90	1.06	0	0.00	1	3.20	0	0.00	0	0.00	0	0.00	91	4.26
NESTOR FALLS DS	13	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.12
NEWINGTON DS	9	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.10

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
NIPIGON DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
NORFOLK TS	131	11.13	2	19.90	0	0.00	0	0.00	0	0.00	1	8.50	134	39.53
NORTH BAY TS	1	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.08
NORTH SHORE DS	17	0.16	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	0.16
NORTHBROOK DS	31	0.52	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	31	0.52
ORANGEVILLE TS DESN1	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
ORANGEVILLE TS DESN2	361	5.44	5	44.23	0	0.00	0	0.00	0	0.00	0	0.00	366	49.67
ORILLIA TS	183	31.84	0	0.00	0	0.00	0	0.00	1	1.65	1	1.06	185	34.55
ORLEANS TS	71	3.10	0	0.00	0	0.00	0	0.00	0	0.00	1	1.00	72	4.10
OTONABEE TS DESN1	17	2.34	0	0.00	1	1.60	0	0.00	0	0.00	0	0.00	18	3.94
OTONABEE TS DESN2	235	9.24	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	235	9.24
OWEN SOUND TS	370	10.62	0	0.00	1	0.10	0	0.00	0	0.00	0	0.00	371	10.72
PALMERSTON TS	256	4.76	1	0.50	0	0.00	0	0.00	0	0.00	0	0.00	257	5.26
PARRY SOUND TS	57	3.63	0	0.00	0	0.00	0	0.00	0	0.00	1	2.00	58	5.63
PEMBROKE TS	33	0.59	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	33	0.59
PETAWAWA DS	12	0.11	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.11
PIC DS	11	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.10
PICTON TS	218	28.78	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	218	28.78
PLEASANT TS DESN1	23	0.31	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	23	0.31

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
PORT ARTHUR TS #1	30	0.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	30	0.28
PORT COLBORNE TS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.04
PORT HOPE TS DESN1	237	34.97	0	0.00	1	0.01	0	0.00	0	0.00	1	5.00	239	39.98
PUSLINCH DS	96	1.60	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	96	1.60
RAMORE TS	12	8.11	0	0.00	0	0.00	0	0.00	1	0.52	0	0.00	13	8.63
RED LAKE TS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.04
RED ROCK DS	29	1.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	29	1.28
ROCKLAND DS	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05
ROCKLAND EAST DS	14	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	14	0.14
RUSSELL DS	7	0.13	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.13
SCHREIBER WINNIPG DS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.08
SEAFORTH TS	102	2.61	1	15.00	0	0.00	0	0.00	0	0.00	0	0.00	103	17.61
SHABAQUA DS	9	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.09
SHARBOT DS	22	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	22	0.19
SIDNEY TS	246	4.04	0	0.00	0	0.00	0	0.00	1	10.00	0	0.00	247	14.04
SIOUX NARROWS DS	4	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.03
SMITHS FALLS TS	256	83.34	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	256	83.34
SOUTH GLOUCESTER DS	13	0.16	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.16
SOUTH MARCH TS	66	1.28	0	0.00	0	0.00	0	0.00	0	0.00	1	6.40	67	7.68

Witness: Peter Faltaous

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
SOUTH MIDDLE ROAD TS	9	0.09	0	0.00	0	0.00	0	0.00	0	0.00	1	13.33	10	13.42
SOWERBY DS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.08
SPANISH DS	6	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.06
ST ISIDORE TS	162	23.10	0	0.00	2	4.70	5	1.22	0	0.00	0	0.00	169	29.03
ST LAWRENCE TS	80	81.25	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	80	81.25
ST MARYS TS	51	1.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	51	1.19
STAYNER TS	199	6.12	2	28.45	0	0.00	0	0.00	0	0.00	0	0.00	201	34.57
STEWARTVILLE TS	83	4.35	0	0.00	0	0.00	0	0.00	1	10.70	0	0.00	84	15.05
STRATFORD TS	170	1.98	0	0.00	0	0.00	3	1.10	0	0.00	0	0.00	173	3.08
STRATHROY TS	59	14.58	1	4.10	0	0.00	0	0.00	0	0.00	0	0.00	60	18.68
STRIKER DS	60	2.54	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	60	2.54
TEMAGAMI DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
THOROLD TS	30	0.26	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	30	0.26
TILBURY WEST DS	48	0.57	1	10.00	0	0.00	0	0.00	0	0.00	0	0.00	49	10.57
TILLSONBURG TS	165	2.01	2	19.80	0	0.00	0	0.00	0	0.00	0	0.00	167	21.81
TIMMINS TS	4	0.04	0	0.00	0	0.00	0	0.00	2	20.50	0	0.00	6	20.54
TROUT LAKE TS	87	2.35	0	0.00	0	0.00	0	0.00	2	10.80	0	0.00	89	13.15
VERMILION BAY DS	8	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.08
VERNER DS	31	0.64	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	31	0.64
WALLACE TS	100	0.97	0	0.00	0	0.00	0	0.00	1	0.60	0	0.00	101	1.57

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
WALLACEBURG TS	175	1.72	1	10.00	0	0.00	0	0.00	0	0.00	1	5.16	177	16.88
WANSTEAD TS	185	3.48	1	10.00	0	0.00	0	0.00	0	0.00	0	0.00	186	13.48
WARREN DS	16	0.71	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	16	0.71
WAUBAUSHENE TS	143	43.69	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	143	43.69
WENDOVER DS	62	13.11	0	0.00	0	0.00	1	0.50	0	0.00	0	0.00	63	13.61
WHARNCLIFFE DS	18	0.18	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	18	0.18
WHITEFISH DS	16	0.62	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	16	0.62
WILHAVEN DS	21	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	21	0.19
WILSON TS DESN2	142	21.96	0	0.00	0	0.00	0	0.00	1	0.01	1	19.40	144	41.37
WINGHAM TS	130	1.98	1	18.00	0	0.00	0	0.00	0	0.00	0	0.00	131	19.98
WOLVERTON DS	61	1.35	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	61	1.35
WONDERLAND TS	39	0.61	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	39	0.61
WOODSTOCK TS	36	2.90	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	37	2.91

Notes on Data

- The FTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only resources directly connected to Hydro One's network are included. Resources that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.

Number and MW of Behind the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2025

The breakdown of behind-the-meter Distributed Energy Resources (BTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by transmission connected station as of December 31, 2025, is as follows:

*Ct=Count, Cap=Capacity

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
AGUASABON DS	25	0.21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	25	0.21
ALLANBURG TS	7	1.78	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	1.78
ALLISTON TS	70	0.81	0	0.00	0	0.00	0	0.00	0	0.00	2	18.24	72	19.05
ALMONTE TS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	9	0.09	14	0.13
ARDOCH DS	27	0.21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	27	0.21
ARMITAGE TS DESN1	37	0.97	0	0.00	0	0.00	0	0.00	0	0.00	1	0.50	38	1.47
ARMITAGE TS DESN2	61	0.88	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	61	0.88
ARNPRIOR TS	52	0.56	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05	57	0.61
AWENDA DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
AYLMER TS	7	0.06	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	8	0.07
BARWICK TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
BARRIE TS	1	0.20	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.20
BATTERSEA DS	17	0.17	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	0.17
BEAMSVILLE TS	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05
BEAVERTON TS	54	0.58	1	0.00	0	0.00	0	0.00	0	0.00	1	0.01	56	0.59
BELLE RIVER TS	14	0.14	1	0.01	0	0.00	0	0.00	0	0.00	1	0.03	16	0.17
BELLEVILLE TS	70	1.60	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	70	1.60

Witness: Peter Faltaous

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
BILBERRY CREEK TS	4	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.03
BIRCH TS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	3.98	2	3.98
BLOOMSBURG DS	36	0.36	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	36	0.36
BRACEBRIDGE TS	7	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.06
BRANT TS	22	0.19	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02	24	0.21
BRANTFORD TS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.02
BROCKVILLE TS	69	1.95	0	0.00	0	0.00	0	0.00	0	0.00	3	3.60	72	5.55
BROWN HILL TS	83	0.71	2	0.01	0	0.00	0	0.00	0	0.00	2	0.64	87	1.36
BUCHANAN TS	6	0.06	0	0.00	0	0.00	0	0.00	0	0.00	3	14.27	9	14.33
BURLEIGH DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
CALEDONIA TS	26	0.26	4	0.01	0	0.00	0	0.00	0	0.00	2	4.00	32	4.28
CENTRALIA TS	26	1.71	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05	31	1.76
CHAPLEAU DS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	1.80	1	1.80
CHERRYWOOD TS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.75	1	0.75
CHESTERVILLE TS	32	0.36	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	32	0.36
CLARABELLE TS	20	0.30	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	20	0.30
CLARENCE DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
CLARKE TS	24	0.64	0	0.00	0	0.00	0	0.00	0	0.00	4	10.46	28	11.10
CLEARWATER BAY DS	6	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.05
COBDEN DS	7	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.07
COBDEN TS	28	0.20	0	0.00	0	0.00	0	0.00	0	0.00	14	0.14	42	0.34
COCHRANE WEST DS	8	0.31	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.31
COMMERCE WAY TS	21	0.69	0	0.00	0	0.00	0	0.00	0	0.00	2	6.10	23	6.79
CONSTANCE DS	10	0.29	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02	12	0.31

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
CRAIG DS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.04
CRAWFORD TS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.79	1	0.79
CROSBY TS DESN1	19	0.26	1	0.00	0	0.00	0	0.00	0	0.00	5	0.05	25	0.31
CROWLAND TS	9	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.07
CRYSTAL FALLS TS	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05
CUMBERLAND DS	15	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.14
DES JOACHIMS DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	3	0.03
DOBBIN DS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
DOBBIN TS	75	0.78	0	0.00	0	0.00	0	0.00	0	0.00	1	2.50	76	3.28
DOUGLAS POINT TS	37	1.09	1	0.25	0	0.00	0	0.00	0	0.00	0	0.00	38	1.34
DRYDEN TS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.04
DUART TS DESN1	12	0.34	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.34
DUNDAS TS	43	0.74	0	0.00	0	0.00	0	0.00	0	0.00	3	0.23	46	0.97
DUNDAS TS #2	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
DUNNVILLE TS	25	0.36	0	0.00	0	0.00	0	0.00	0	0.00	3	0.04	28	0.41
DYMOND TS	5	0.07	0	0.00	0	0.00	0	0.00	0	0.00	2	3.07	7	3.13
EDGEWARE TS	55	0.98	0	0.00	0	0.00	0	0.00	0	0.00	3	11.10	58	12.08
ELMIRA TS	2	0.05	0	0.00	0	0.00	0	0.00	0	0.00	1	2.30	3	2.35
ENFIELD TS DESN 1	17	0.17	0	0.00	0	0.00	0	0.00	0	0.00	1	0.52	18	0.69
ESPANOLA TS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
ETON DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
EVERETT TS	19	0.34	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	20	0.35
FAUQUIER DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
FERGUS TS	129	2.28	0	0.00	0	0.00	0	0.00	0	0.00	2	0.04	131	2.32
FOREST JURA DS	25	0.87	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	25	0.87
FOREST LEA DS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.08

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
FRONTENAC TS	52	0.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	52	0.65
GALT TS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
GODERICH TS	7	0.18	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	8	0.19
GRAND BEND EAST DS	7	0.11	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.11
GREELY DS	40	0.39	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	40	0.39
HANOVER TS	92	1.30	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	92	1.30
HARROWSMITH DS	26	0.22	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	26	0.22
HAVELOCK TS	45	0.37	0	0.00	0	0.00	0	0.00	0	0.00	7	4.06	52	4.43
HAWTHORNE TS	48	0.67	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	48	0.67
HEARST TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
HERRIDGE LAKE DS	2	0.15	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03	5	0.18
HIGHBURY TS	13	0.23	0	0.00	0	0.00	0	0.00	0	0.00	2	6.00	15	6.22
HINCHINBROOKE DS	5	0.03	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05	10	0.08
HOLLAND TS	16	0.37	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	16	0.37
HOYLE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
INGERSOLL TS	36	1.51	0	0.00	0	0.00	0	0.00	0	0.00	14	0.14	50	1.65
JARVIS TS	21	0.55	2	0.01	0	0.00	0	0.00	0	0.00	4	0.03	27	0.59
KAPUSKASING TS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	1	0.16	4	0.18
KEEWATIN DS	13	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.12
KEITH TS DESN1	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	3.40	1	3.40
KENORA DS	17	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	0.14
KENT TS DESN1	17	0.37	0	0.00	0	0.00	0	0.00	0	0.00	1	5.00	18	5.37
KENT TS DESN2	5	0.13	0	0.00	0	0.00	0	0.00	0	0.00	3	2.40	8	2.53
KINGSTON GARDINER TS DESN1	58	0.49	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	58	0.49

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
KINGSTON GARDINER TS DESN2	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	2	16.80	3	16.81
KINGSVILLE TS	20	0.41	0	0.00	0	0.00	0	0.00	0	0.00	1	0.82	21	1.23
KIRKLAND LAKE TS	11	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.10
KLEINBURG TS	62	0.86	1	0.01	0	0.00	0	0.00	0	0.00	4	4.63	67	5.50
LAFOREST ROAD DS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.02
LAMBTON TS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
LARCHWOOD TS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04	13	0.12
LAUZON TS DESN1	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.95	1	0.95
LAUZON TS DESN2	6	0.31	0	0.00	0	0.00	0	0.00	0	0.00	1	0.75	7	1.06
LDC Owned Station	6	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.06
LEAMINGTON TS DESN 1	12	0.32	0	0.00	0	0.00	0	0.00	0	0.00	1	10.00	13	10.32
LEAMINGTON TS DESN 2	2	0.51	0	0.00	0	0.00	0	0.00	0	0.00	1	0.82	3	1.33
LINDSAY TS	42	1.50	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05	47	1.55
LODGEROOM DS	15	0.18	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.18
LONGLAC TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
LONGUEUIL TS	40	0.89	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	40	0.89
LONGWOOD TS	41	0.51	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	41	0.51
MALDEN TS	8	0.07	0	0.00	0	0.00	0	0.00	0	0.00	1	9.20	9	9.27
MANITOULIN TS	32	0.80	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	33	0.81
MANOTICK DS	13	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.12
MARATHON DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
MARGACH DS	15	0.12	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	16	0.13
MARIONVILLE DS	13	0.20	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.20

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
MARTINDALE TS	27	0.24	0	0.00	0	0.00	0	0.00	0	0.00	7	0.07	34	0.30
MASSEY DS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
MATTAWA DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	3	0.03
MAZINAW DS	72	0.67	0	0.00	0	0.00	0	0.00	0	0.00	1	2.99	73	3.66
MEAFORD TS	50	0.55	0	0.00	0	0.00	0	0.00	0	0.00	3	0.77	53	1.32
MIDHURST TS DESN1	67	0.58	1	0.00	0	0.00	0	0.00	1	0.04	0	0.00	69	0.62
MINAKI DS	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.00
MINDEN TS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	30	0.30	39	0.38
MONTEITH DS	15	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.14
MORRISBURG TS	8	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.07
MURILLO DS	78	1.13	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03	81	1.16
MUSKOKA TS	48	0.47	0	0.00	0	0.00	0	0.00	0	0.00	29	0.29	77	0.76
NAPANEE TS	13	0.51	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.51
NAVAN DS	33	0.39	0	0.00	0	0.00	0	0.00	0	0.00	2	5.25	35	5.64
NEBO TS DESN1	10	0.32	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	10	0.32
NESTOR FALLS DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
NEWINGTON DS	23	0.42	0	0.00	0	0.00	0	0.00	0	0.00	1	0.75	24	1.17
NORFOLK TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
NORTHBROOK DS	4	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.03
ORANGEVILLE TS DESN1	4	0.13	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02	6	0.15
ORANGEVILLE TS DESN2	129	1.64	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	130	1.65
ORILLIA TS	63	0.58	0	0.00	0	0.00	0	0.00	0	0.00	4	3.28	67	3.87
ORLEANS TS	39	0.41	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	39	0.41
OTONABEE TS DESN1	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04	13	0.12

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
OTONABEE TS DESN2	70	1.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	70	1.01
OWEN SOUND TS	229	2.27	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	230	2.27
PALMERSTON TS	61	2.28	0	0.00	0	0.00	0	0.00	0	0.00	1	0.13	62	2.41
PARRY SOUND TS	50	0.41	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	51	0.42
PEMBROKE TS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
PETAWAWA DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	2	3.05	5	3.08
PIC DS	2	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.01
PICTON TS	95	0.91	1	0.08	0	0.00	0	0.00	0	0.00	0	0.00	96	0.99
PLEASANT TS DESN1	5	0.03	0	0.00	0	0.00	0	0.00	0	0.00	1	0.95	6	0.98
PORT ARTHUR TS #1	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04	9	0.09
PORT HOPE TS DESN1	64	2.17	0	0.00	0	0.00	0	0.00	0	0.00	1	3.00	65	5.17
PUSLINCH DS	37	0.35	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	37	0.35
RAMORE TS	3	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.19
RED LAKE TS	2	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.01
ROCKLAND DS	6	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.05
ROCKLAND EAST DS	17	0.22	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	18	0.23
RUSSELL DS	7	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.06
SAM LAKE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
SAPAWE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
SCHREIBER WINNIPG DS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.02
SEAFORTH TS	16	1.01	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	17	1.02
SHARBOT DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
SIDNEY TS	53	0.44	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	53	0.44

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
SIOUX NARROWS DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
SMITHS FALLS TS	114	1.68	0	0.00	0	0.00	0	0.00	0	0.00	66	1.87	180	3.55
SOUTH GLOUCESTER DS	6	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.05
SOUTH MARCH TS	38	0.36	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	38	0.36
SOWERBY DS	2	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.01
SPANISH DS	3	0.18	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.18
ST ISIDORE TS	38	2.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	38	2.19
ST LAWRENCE TS	24	0.22	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	24	0.22
ST MARYS TS	10	0.45	0	0.00	0	0.00	0	0.00	0	0.00	1	1.76	11	2.20
STAYNER TS	72	0.83	0	0.00	0	0.00	0	0.00	0	0.00	3	11.16	75	11.99
STEWARTVILLE TS	27	0.22	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	28	0.23
STRATFORD TS	34	1.79	0	0.00	0	0.00	0	0.00	0	0.00	3	4.51	37	6.29
STRATHROY TS	6	0.29	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.29
STRIKER DS	4	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.08
TEMAGAMI DS	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
THOROLD TS	5	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.09
TILBURY WEST DS	6	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.14
TILLSONBURG TS	42	0.90	0	0.00	0	0.00	0	0.00	0	0.00	26	1.07	68	1.97
TIMMINS TS	1	0.07	0	0.00	0	0.00	0	0.00	0	0.00	1	1.57	2	1.65
TROUT LAKE TS	33	0.29	0	0.00	0	0.00	0	0.00	0	0.00	73	0.73	106	1.02
VERMILION BAY DS	2	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.09
VERNER DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
WALLACE TS	32	0.24	0	0.00	0	0.00	0	0.00	0	0.00	47	0.47	79	0.71
WALLACEBURG TS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
WANSTEAD TS	4	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.07

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
WARREN DS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.02
WAUBAUSHENE TS	53	0.41	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	53	0.41
WENDOVER DS	21	0.44	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	21	0.44
WHARNCLIFFE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	2	0.02
WHITEFISH DS	14	0.12	0	0.00	0	0.00	0	0.00	0	0.00	11	0.11	25	0.23
WILHAVEN DS	11	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.19
WILSON TS DESN2	37	16.03	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	38	16.04
WINGHAM TS	24	0.76	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	24	0.76
WOLVERTON DS	17	0.26	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03	20	0.29
WONDERLAND TS	8	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.08
WOODSTOCK TS	28	1.58	0	0.00	0	0.00	0	0.00	0	0.00	2	1.01	30	2.59
SHABAQUA DS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	1	0.01
SHARBOT DS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03	3	0.03

Notes on Data

- The BTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only DERs directly connected to Hydro One's network are included. DERs that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.
- The list only consists of BTM DER Resources that Hydro One has records of. There may be BTM DERs that are utilized by customers for their own purposes (e.g. backup diesel generation in mines). As customers have no obligation to inform Hydro One of these installations, these installations are neither tracked nor included in this list.

SECTION 3.4 – Attachment 7 - RGCRP FUNDING REQUEST

APPLICATION SUMMARY

1.0 INTRODUCTION

Pursuant to Section 79.1 of the *Ontario Energy Board Act, 1998* and Ontario Regulation 330/09 (O. Reg. 330/09), Hydro One is requesting Renewable Generation Connection Rate Protection (RGCRP) amounts effective January 1, 2028 for Hydro One Distribution and Peterborough RZ. This exhibit provides the details on the requested RGCRP amounts for each RZ.

Accordingly, this exhibit contains the following sections:

- Section 2.0 – Hydro One Distribution RGCRP Request
    - 2.1 Background
    - 2.2 Requested RGCRP Funding for Hydro One Distribution
- Section 3.0 – Peterborough RZ RGCRP Request
    - 3.1 Background
    - 3.2 Requested RGCRP Funding for Peterborough RZ
- Section 4.0 – List of Attachments

SUMMARY OF OEB DECISIONS

This Exhibit provides a summary of decisions from Hydro One's past proceedings.

1. EB-2023-0291 – Hydro One Networks' Application for Renewable Generation Connection Rate Protection Compensation Amount (RGCRP)[1]

On May 7, 2024, the OEB approved the settlement proposal reached by Hydro One Networks Inc. (HONI) and OEB staff for Hydro One Distribution, the Haldimand rate zone, and the Peterborough rate zone. The settlement proposal addressed all issues raised throughout the application process. The OEB approved RGCRP funding for 2025-2027 for Hydro One Distribution and for 2024-2027 for the Peterborough Rate Zone. Based on updated Haldimand Rate Zone RGCRP models from interrogatories and pre-settlement discussions, the Parties agreed and the OEB approved, that Hydro One will request disposition of the Account 1533 balance for Haldimand Rate Zone and discontinue the account in its next Custom IR rebasing application.

The Decision and Order also identified the following outstanding items for future filings:

- Haldimand RZ Account 1533 disposition: the OEB ordered that Hydro One seek approval to dispose of the Account 1533 balance and close the account for the Haldimand rate zone as part of its next Custom IR rebasing application.
- Prudence review of actual costs: as RGCRP funding for Hydro One Distribution and the Peterborough RZ is based on forecast costs, Hydro One is expected to file evidence at its next rebasing application supporting the OEB's review for prudence of the actual incurred cost of the in-service assets.
- Support for future project funding: the OEB does not normally approve RGCRP funding for new renewable generation connections outside of a rebasing application; future applications are expected to include details of future projects

[1] EB-2023-0291, Decision and Order, May 7, 2024

(capital costs and incremental start-up OM&A) upfront, rather than relying on interrogatories to surface this information.

- General filing guidance: Hydro One is urged to review the Framework for Direct Benefits, the most updated OEB Accounting Procedures Handbook Guidance, and any associated filing requirements prior to future RGCRP filings.

2. EB-2013-0416 – Hydro One Networks' 2015-2019 Distribution Rate Application

On December 18, 2014, the OEB issued a decision and interim rate order, which granted Hydro One's request to discontinue the collection of revenue through the Regulation 330/09 renewable generation connection funding adder from provincial ratepayers on December 31, 2014.[2]

3. EB-2009-0096 – Hydro One Networks' 2010 and 2011 Distribution Rate Application

On February 18, 2010, the OEB issued a partial decision that approved the methodology proposed by Hydro One for the allocation of Green Energy Plan costs for rate-setting purposes, on a provisional basis.[3]

1.1 BACKGROUND

In its EB-2023-0291 Decision and Order, the OEB authorized Hydro One to collect $17.0M in RGCRP amounts from the IESO for the years 2025 - 2027 commencing January 1, 2025. RGCRP funding had been discontinued back in 2014 and was being restarted.

Table 1 - RGCRP Funding from the Settlement for 2025-2027[4]

Years	2025	2026	2027	Total
Annual Amount - Settlement	$3,068,005	$6,986,604	$6,942,106	$16,996,715

[2] EB-2013-0419, Decision and Interim Rate Order, December 18, 2014.
[3] EB-2009-0096, Partial Decision, February 18, 2010, p.4.
[4] EB-2023-0291, Decision and Order, Table 1, May 7, 2024, p. 4

Since 2014, Hydro One has funded the investments necessary to connect renewable generation by drawing down the balance that had accumulated in the deferral account. As shown below in Table 2, the deferral account balance as at December 31, 2025 (inclusive of principal and interest) is -$0.1M which indicates that funding and actual revenue requirement are closely aligned.

Table 2 - Summary of Hydro One Distribution Account 1533 Provincial Sub-Account Balances ($M) [5]

	Balance as at Dec 31, 2023	Balance as at Dec 31, 2024	Balance as at Dec 31, 2025
Provincial Other Green Energy Plan Sub-Account			
Principal	8.6	-1.9	-0.1
Interest	-1.9	-1.9	0.0
Total	6.6	-3.8	-0.1
Provincial Express Feeders Sub-Account			
Principal	0.0	0.0	0.0
Interest	0.0	0.0	0.0
Total	0.0	0.0	0.0

1.2 REQUESTED RGCRP FUNDING FOR HYDRO ONE DISTRIBUTION

HONI requests that the OEB authorize Hydro One Distribution to collect RGCRP monthly compensation amounts from provincial electricity consumers effective January 1, 2028.

Given the continuing need to provide funding for both the historical renewable generation connection investments and any future renewable generation connection investments, Hydro One seeks approval to:

- receive annual payments for 2028 through 2032 for the provincially-funded portion of these investments, starting January 1, 2028. The annual payments requested are, as follows:
    - $7,612,315 for 2028 ($634,360 per month);
    - $8,437,776 for 2029 ($703,148 per month);

[5] For additional details, please refer to DSP Section 3.4, Attachment 7, HONI RGCRP Model – Tab 5, Account 1533 Continuity Schedule for Hydro One Distribution (excluding Haldimand)

- $9,651,322 for 2030 ($804,277 per month);
- $10,865,502 for 2031 ($905,459 per month); and,
- $12,063,888 for 2032 ($1,005,324 per month).

Section 2.3 describes the revenue requirement model supporting the compensation amounts that Hydro One requests. This request for RGCRP funding meets Hydro One's materiality threshold per section 2.0.8 of the Filing Requirements. Hydro One will continue to record compensation amounts received and expenditures related to renewable generation connection investments in Account 1533, as required.

1.3 RGCRP REVENUE REQUIREMENT MODEL

Due to the custom nature of Hydro One's calculations, Hydro One has filed its custom RGCRP revenue requirement model as "HONI Dx (RGCRP Model)" provided at Attachment 1 to this exhibit. The model sets out the revenue requirement calculations used to determine the revenue requirement amounts for investments made prior to January 1, 2028 and for 2028-2032 annual IESO payment amounts. Hydro One's calculations are equivalent to those set out in the OEB's Chapter 2 Appendices 2-FA, 2-FB and 2-FC, and are consistent with the calculations approved in EB-2023-0291.

The RGCRP revenue requirement calculations in Hydro One's model are based on actual renewable generation in-service additions and OM&A expenditures from 2010 through 2025 and forecasted renewable generation in-service additions and OM&A expenditures for 2026-2032. To determine the provincial portion of these costs, Hydro One assumed the following direct benefit percentages, which were established in EB-2009-0096 as part of Hydro One's Green Energy Plan:[6]

- Expansion – 18.2% direct benefit for Hydro One Distribution (81.8% allocated to provincial rate payers); and

[6] EB-2009-0096, Exhibit A, Tab 14, Schedule 2, pp. 17-23.

- REI – 5% direct benefit for Hydro One Distribution (95% allocated to provincial rate payers).[7]

The forecasted renewable generation in-service additions and OM&A expenditures underpinning the revenue requirement are provided below in Table 3.

Table 3 - Total Renewable Generation Connection Program Costs Included in 2028-2032 Rates ($M)[8]

	2028	2029	2030	2031	2032
In-Service Additions	6.4	14.3	14.4	14.5	14.7
OM&A	0.7	0.7	0.8	0.8	0.8

The provincial portion of the actual and forecasted in-service additions and OM&A expenditures are provided on Tab 1 of HONI Dx (RGCRP Model). The provincial portion of the in-service additions are used to determine each year's net fixed assets additions and income taxes (calculated on Tabs 2 and 3 respectively), which, in combination with the provincial portion of the OM&A expenditures, are used to calculate the revenue requirement in Tab 4.

2.0 PETERBOROUGH RZ RGCRP REQUEST

2.1 BACKGROUND

In its EB-2023-0291 Decision and Order, the OEB approved the collection of RGCRP funding in the amount of $58.2K for the Peterborough RZ for the period 2024 – 2027 commencing January 1, 2024.

[7] In Hydro One's Green Energy Plan, the Company noted that the direct benefit allocation associated with REI work could range from 5% for work on remote protection and control of sub-transmission reclosers to 9% for SCADA work at distribution stations. In practice, most REI scopes do not involve SCADA work at the Dx stations. Given the SCADA work is relatively immaterial, Hydro One has assumed a 5% direct benefit percentage for its REI investments.
[8] These amounts correspond to the total REI and Expansion investments in Tab 1 of HONI Dx (RGCRP Model) prior to the provincial allocation.

Table 4 - RGCRP Funding from the Settlement for 2024 – 2027 for the Peterborough RZ[9]

Year	2024	2025	2026	2027	Total
Annual Amount - Settlement	$15,104	$13,799	$14,370	$14,926	$58,199

Since the integration of Peterborough RZ, Hydro One has continued to make investments necessary to connect renewable generation. As shown in the continuity schedule for Peterborough RZ's provincial portion of Account 1533 (see Attachment 2, Tab 2 of Peterborough RZ RGCRP Model) and Table 5 below, the balance in the deferral account moved from a debit position of $103,145 as at December 31, 2023 to a credit position of $1,198 and $2,183 as at December 31, 2024 and December 31, 2025, respectively. Notwithstanding this credit position, Hydro One forecasts $268,070 of additional capital related to small embedded generation expansions and REI to be put into service for the Peterborough RZ between 2027 and 2032, requiring additional funding for these investment costs through the provincial pooling mechanism.

Table 5 - Summary of Peterborough RZ Account 1533 Provincial Sub-Account Balances

	Balance as at Dec 31, 2023	Balance as at Dec 31, 2024	Balance as at Dec 31, 2025
Provincial Distribution Generation Sub-Account			
Principal	$103,145	-$1,198	-$2,183
Interest	$0	$0	$0
Total	**$103,145**	**-$1,198**	**-$2,183**

2.2 REQUESTED RGCRP FUNDING FOR PETERBOROUGH RZ

For its Peterborough RZ, Hydro One requests an amendment to the RGCRP monthly compensation amounts from provincial electricity consumers effective January 1, 2028. In

[9] EB-2023-0291, Decision and Order, Table 2, May 7, 2024, p. 5

EB-2023-0291, Peterborough RZ received total compensation of $58.2K for years 2024 – 2027.

Given the continuing need to provide funding for both the historical renewable generation connection investments and any future renewable generation connection investments, Hydro One seeks approval to:

- receive annual payments for 2028 through 2032 for the provincially-funded portion of these investments, starting January 1, 2028. The annual payments requested are, as follows:
    - $13,793 for 2028 ($1,149 per month);
    - $20,678 for 2029 ($1,723 per month);
    - $24,371 for 2030 ($2,031 per month);
    - $28,007 for 2031 ($2,334 per month); and
    - $31,584 for 2032 ($2,632 per month).

Hydro One has filed the revenue requirement model for Peterborough RZ as "Peterborough RZ (RGCRP Model)" provided at Attachment 2, which provides equivalent revenue requirement calculations as those required in the OEB's Chapter 2 Appendices 2-FA, 2-FB and 2-FC.

2.2.1 RGCRP REVENUE REQUIREMENT MODEL

The revenue requirement calculations are based on actual renewable generation in-service additions and OM&A expenditures from 2023 through 2025; and forecasted renewable generation in-service additions and OM&A expenditures for 2026-2032. To determine the provincial portion of these costs, Hydro One assumed the following direct benefit percentages:

- For 2023-2027, Hydro One assumed a direct benefit percentage of 17% for all investments. This is based on the historical assumptions applied by PDI and is consistent with the OEB's policy for renewable energy generation expansion investments, set in EB-2009-0349 and in Chapter 2 of the Filing Requirements for

Electricity Distribution Rate Applications. No material REI investments were made for the Peterborough RZ.

- For 2028-2032, as Peterborough RZ remains on deferred rebasing, the model continues to assume a direct benefit percentage of 17% to align with past practice for PDI. Hydro One forecasts $268,070 of additional capital related to small embedded generation expansions and REI to be put into service for the Peterborough RZ between 2027 and 2032. This forecast includes REI-related capital, which for modeling purposes is included within the 17% direct benefit calculation applicable to expansion-type investments for the Peterborough RZ, rather than being assigned a separate REI direct benefit rate.

4.0 LIST OF APPENDICES

The following appendices are provided as part of this section:

- Hydro One Distribution RGCRP Revenue Requirement Model (HONI Dx RGCRP Model) - Attachment 1
- Peterborough RZ RGCRP Revenue Requirement Model (Peterborough RZ RGCRP Model) - Attachment 2

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SECTION 3.4 – ATTACHMENT 7.1- DX CHAPTER 2 APPENDIX: 2FA 2FB 2FC HONI HYDRO ONE DISTRIBUTION RGCRP REVENUE REQUIREMENT

This attachment has been filed separately in MS Excel format.

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SECTION 3.4 – ATTACHMENT 7.2- DX CHAPTER 2 APPENDIX: 2FA 2FB 2FC PRZ PETERBOROUGH RZ RGCRP REVENUE REQUIREMENT

This attachment has been filed separately in MS Excel format.

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SECTION 3.5 – DSP – PERFORMANCE MEASUREMENT AND OUTCOMES

3.5.1 INTRODUCTION

The Renewed Regulatory Framework (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, shows Hydro One's progress in achieving these outcomes and the performance levels that Hydro One expects to achieve over the 2028-2032 planning 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 to track performance outcomes that customers value and measure areas that Hydro One has targeted for sustained or improved performance.

The Distribution OEB Scorecard as proposed in EB-2021-0110 was adopted as part of the same proceeding's settlement agreement. With the exception of the proposed revisions noted below, Hydro One will continue to use the measures approved in the EB-2021-0110 application and has presented the prior application's targets up to 2027 (the Bridge year). Any instances where the methodology to establish a target has been revised are reflected below on a metric-by-metric basis.

Hydro One has made the following additions to the Distribution Scorecard. Supporting details for these proposals are provided below on a metric-by-metric basis:

- Added a metric for Kilometers of Forestry Managed

- Added a metric to measure the Distribution Capital Program Work Composite Index (DCAI)
- Added a metric for Flexibility & Local Energy Efficiency Programs
- Added a metric to Enabling Remote Operable Capabilities
- Added a metric for Load Capacity Constrained Distribution Stations

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 the performance measures as it evaluates its progress executing its 2028 to 2032 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 2027 in the last distribution application (EB-2021-0110). The evidence that follows provides Hydro One's actual results for the years 2021-2025, compared against the Hydro One Target established in EB-2021-0110 where appropriate. In addition, Hydro One has proposed targets for the 2028-2032 period.

3.5.2 OEB ELECTRICITY DISTRIBUTOR SCORECARD

The Electricity Distributor Scorecard is provided in Figure 1 below and includes targets for the 2028 to 2032 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		2021	2022	2023	2024	2025	Trend	OEB Targets 2025 Industry	OEB Targets 2025 Distributor	Hydro One Targets 2026	2027	2028	2029	2030	2031	2032
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time		99.98%	99.86%	99.97%	99.94%	99.95%	▲	90.00%		99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		Scheduled Appointments Met On Time		100.00%	99.99%	100.00%	100.00%	96.62%	▼	90.00%		99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		Telephone Calls Answered On Time		70.41%	72.65%	78.24%	78.01%	66.70%	▼	65.00%		80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
	Customer Satisfaction	First Contact Resolution		77.00%	74.00%	74.00%	76.00%	73.00%	▼			88.0%	88.0%	78.0%	80.0%	81.0%	83.0%	85.0%
		Billing Accuracy		99.17%	99.01%	99.04%	98.94%	98.76%	▼	98.00%		98.0%	98.0%	98.5%	98.8%	98.3%	98.3%	98.3%
		Customer Satisfaction Index		82.4%	82.4%	82.1%	85.7%	85.00%	▲			86.0%	87.0%	82.0%	82.0%	82.0%	82.0%	82.0%
Operational Effectiveness	Safety	Level of Public awareness		78.00%	81.00%	81.00%	82.00%	82.00%	▲			80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
		Compliance with Ontario Regulation 22/04		C	C	C	C	C	►		C	C	C	C	C	C	C	C
	Safety	Serious Electrical Incident Index	Number of General Public Incidents	15	40	48	28	127	▲		23							
			Rate per 1000km of line	0.120	0.321	0.385	0.223	1.009	▲		0.183							
	System Reliability	SAIDI - Average Number of Hours that Power to a Customer Is Interrupted		6.5	6.9	7.5	7.7	8.2	▲		4.3	7.8	7.7	7.6	7.5	7.4	7.3	7.2
		SAIFI - Average Number of Times that Power to a Customer Is Interrupted		2.4	2.5	2.8	2.7	2.9	▲		1.9	2.7	2.7	2.7	2.7	2.7	2.7	2.7
	Asset Management	Distribution System Plan Implementation Progress		100.90%	126.03%	101.17%	105.30%	111.78%	▲			100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	Cost Control	Efficiency Assessment		4	4	4	4	4	►			4	4					
		Total Cost per Customer		$1,033	$1,172	$1,369	$1,384	$1,399	▲									
		Total Cost per km of Line		$11,940	$13,537	$15,970	$16,326	$16,558	▲									
Public Policy Responsiveness	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time		98.72%	96.63%	90.00%	90.67%	92.30%	▼	90.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.64	0.50	0.55	0.53	0.59										
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.72	1.63	1.84	1.99	2.08										
		Profitability: Regulatory Return on Equity	Deemed	9.00%	9.00%	9.36%	9.36%	9.36%										
			Achieved	10.99%	10.10%	10.88%	9.79%	11.38%										

Figure 1: Electricity Distributor Scorecard

3.5.2.1 CUSTOMER FOCUS MEASURES

3.5.2.2 SERVICE QUALITY

3.5.2.2.1 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 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
New Residential/Small Business Services Connected on Time	99.98%	99.86%	99.97%	99.94%	99.95%	▲	90.00%		98.0%	98.0%	98.0%

Performance on this measure has trended positively over the 2021 to 2025 period, averaging 99.9% on-time connections for new residential and small business services, consistently exceeding the industry target of 90%.[1]

From 2021-2025, Hydro One processed an average of 15,078 new connection requests per year for residential and small business low-voltage customers (those with service less than 750 V). Of these, an average of 99.9% were completed within five business days (or as otherwise agreed to by the customer and the distributor), better than the industry target of 90% and the Hydro One internal target of 98%.

[1] New Residential/Small Business Services connected on Time is shown in Exhibit A-05-01 and A-05-01, Attachment 1, as Low Voltage Connections.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measure	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
New Residential/Small Business Services Connected on Time	90%		99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%

For this metric, Hydro One has established internal performance targets higher than the OEB target. The Company's performance 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%. For the 2026-2032 period, the internal target has increased to 99%, reflecting Hydro One's continued commitment to improving the timeliness and quality of customer service.

3.5.2.2.2 SCHEDULED 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 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 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Scheduled Appointments Met On Time	100.00%	99.99%	100.00%	100.00%	96.62%	▼	90.0%		99.0%	99.0%	99.0%

Over the past five years, Hydro One has averaged 99.3% for its ability to meet scheduled appointments on time and performance has trended positively, consistently exceeding the OEB target of 90%.[2]

[2] Scheduled Appointments Met on Time is shown in Exhibit A-05-01 and A-05-01, Attachment 1, as Appointments Met.

Witness: Gianni DiFilippo; Spencer Gill; Aimee Oabel

From 2021 to 2025, Hydro One scheduled and met an average of 29,649 appointments per year where the customer presence was required. The Business recorded an average 99.7% success rate in meeting these commitments, better than the industry target of 90% and the Hydro One internal target of 99%.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measure	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Scheduled Appointments Met On Time	90.00%		99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%

Hydro One continues to challenge itself by setting internal performance targets higher than OEB standards and industry targets. The Company's steady performance over the past five years is mainly attributable to strong customer-focused business processes, improvements in scheduling practices, and focus on achievement of an internal target of 99%.

3.5.2.2.3 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.

HISTORICAL PERFORMANCE AND VARIANCE TO 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Telephone Calls Answered On Time	70.41%	72.65%	78.24%	78.01%	66.70%	▼	65.00%		80.0%	80.0%	80.0%

Average performance over the past five years was 73.2%. While the trend since 2021 indicates some reduction in the timeliness of answering telephone calls, performance has remained above the industry target of 65%[3].

In 2021 and 2022, Hydro One answered an average of 70 percent of calls within 30 seconds. Although this outcome exceeded the industry target, it fell below the utility's internal target of 80 percent. Hydro One attributes this variance primarily to the prolonged operational impacts of significant disruptions experienced in 2020 that extended into the following years.

In March 2020, Hydro One shifted its contact centre to work-from-home, requiring changes to processes, technology, and supervision. During this transition, average handle times increased as agents adapted to new remote workflows and tools, resulting in longer wait times. In October 2020, Hydro One implemented a new telephony platform during fully remote operations. Adoption and stabilization challenges resulted in an increase in handling times. At the same time, call volumes rose due to the Customer Choice rate election program and a winter storm that impacted approximately 240,000 customers. These impacts extended into 2021 and 2022 due to continued agent ramp-up in a remote environment, new staff onboarding, and ongoing telephony stabilization.

In 2023 and 2024, Hydro One answered 78.24% and 78.01% of calls within 30 seconds, respectively. Performance in both years exceeded the industry standard, demonstrating recovery and improved consistency in contact centre operations.

[3] Telephone Calls Answered on Time is shown in Exhibit A-05-01 and A-05-01, Attachment 1, as Telephone Accessibility.

Witness: Gianni DiFilippo; Spencer Gill; Aimee Oabel

In 2025, Hydro One answered 66.7% of calls within 30 seconds. This exceeded the industry target, but was below the company's internal target for the following reasons:

- Hydro One experienced a significant storm event causing widespread outages across the province with 1.2 million service interruptions impacting over 600,000 customers or 42 percent of total Hydro One customers impacted. The resulting 230,000 customer calls created sustained pressure on the contact centre for several weeks.
- A Canada Post strike disrupted delivery of bills, statements, and other customer communications. This increased call volumes as customers sought clarification regarding account status, payment options, and missing correspondence.
- In June 2025, Hydro One migrated its on-premise telephony platform to a cloud platform, impacting call handle times while the transition took place.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Telephone Calls Answered On Time	65.00%		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 2028 to 2032, which remains consistent with the targets set for 2026 and 2027. Maintaining performance against this metric is supported by the Customer Care OM&A program (Exhibit E-03-04), which funds the resources, processes, training, and customer service capabilities required to deliver timely and effective customer support. As outlined in Exhibit E-03-04, Hydro One continues to experience increasing complexity in customer interactions driven by factors such as electrification, distributed energy resources, evolving billing and pricing options, and increased demand for digital and self-service channels. These trends require enhanced frontline support, workforce development, and quality assurance.

Over the rate period, Hydro One will continue to support this performance target through enhanced workforce training and upskilling, quality assurance, customer experience analytics, and digital service enhancements. These initiatives are intended to improve

operational efficiency, support first-contact resolution, and enable Hydro One to respond effectively to changing customer expectations while maintaining established service levels. While annual results may vary due to factors such as call volume fluctuations, major weather events, and changing customer needs, Hydro One expects that the proposed Customer Care OM&A investments will support continued achievement of this performance metric throughout the 2028 to 2032 period.

3.5.2.3 CUSTOMER SATISFACTION

3.5.2.3.1 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 call, 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 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
First Contact Resolution	77.00%	74.00%	74.00%	76.00%	73.00%	▼			88.0%	88.0%	88.0%

As part of the last distribution application, Hydro One proposed a First Contact Resolution ("FCR") target of 88% for each year from 2023-2027. Performance for FCR over the prior five years has trended downwards, averaging 74.8% over this same period, which is below Hydro One's target. Hydro One identified a number of reasons for this performance relative to target:

- Hydro One has expanded and enhanced its digital and self-service channels, enabling customers to complete a greater proportion of routine transactions online or through the Interactive Voice Response system. As a result of these channel improvements, simple transactional inquiries increasingly bypass the call centre, reducing the volume of low complexity interactions handled by Customer Service Representatives. This shift has changed the call centre interaction mix, with Customer Service Representatives managing a higher proportion of complex,

multistep, and higher effort customer issues that require additional time, investigation, or coordination to resolve.

- During outage events, customers frequently contact the call centre to request an Estimated Time of Restoration. These inquiries often cannot be conclusively resolved at first contact, as restoration times depend on field verification, damage assessments, and evolving system conditions. As a result, outage related calls have a lower likelihood of first contact resolution, which places downward pressure on overall FCR performance.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
First Contact Resolution			88.0%	88.0%	78.0%	80.0%	81.0%	83.0%	85.0%

Hydro One has established a phased approach to improving First Contact Resolution supported by targeted process enhancements, workforce upskilling, and increased use of technology. Annual performance targets are set to begin at 78 percent in 2028 and increase by 1 to 2 percentage points per year, reaching 85 percent by 2032. These targets reflect a gradual return toward historical performance levels, while remaining below the previously established 88 percent target in recognition of increasing call complexity and the continued evolution of customer service channels. Performance on this metric is primarily supported through its Customer Care Program OM&A (Exhibit E-03-04). Hydro One is committed to improving performance on this metric over the rate period through continuous improvement initiatives focused on enhancing the customer experience, including targeted process improvements, resource upskilling, and enhancing digital tools.

3.5.2.3.2 BILLING ACCURACY

Performance Category	Measure	Description
Customer Satisfaction	Billing Accuracy	Billing Accuracy is the measure for the number of bills issued that are derived based on actual meter readings and do not require any subsequent bill adjustments as a percentage of the total number of billes issued in a given bill period.

HISTORICAL PERFORMANCE AND VARIANCE TO 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Billing Accuracy	99.17%	99.01%	99.04%	98.94%	98.76%	▼	98.0%		98.0%	98.0%	98.0%

Billing accuracy has remained above the industry and Hydro One target for the past 5 years.

Between 2021 and 2023, over 14 million bills were issued annually and achieved a 98.76% billing accuracy in 2025, exceeding the industry target by 0.82% and the Hydro One target by the same. The billing accuracy results are attributable to ongoing business process optimization, improving training, ensuring relevant controls are built into new projects from inception and a continued focus on addressing meters that do not meet the necessary quality levels.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Billing Accuracy	98.00%		98.0%	98.0%	98.5%	98.8%	98.3%	98.3%	98.3%

In EB-2021-0110, Hydro One established a billing accuracy target of 98% for 2026 and 2027 to reflect the aging AMI 1.0 metering system. Installed between 2007 and 2013, these meters have reached the end of their 15-year service life, and failure rates are increasing. Hydro One began a mass replacement program to transition from AMI 1.0 to AMI 2.0 meters through 2029. Billing accuracy is expected to dip as older meters continue to fail, then improve as the AMI 2.0 meter population grows and the new network becomes fully operational.

Hydro One continues to mitigate billing risks through process and system improvements across the meter to cash cycle, including enhanced validation controls, standardized procedures, improved staff training, and proactive monitoring to detect and resolve issues earlier. The AMI 2.0 deployment will further strengthen billing accuracy by expanding

network coverage, reducing manual reads, and improving data quality as consumption patterns evolve.

Hydro One is committed to maintaining strong billing accuracy performance throughout the upcoming rate setting period.

3.5.2.3.3 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) myAccount; (6) Large Distribution Accounts (LDAs); and (7) Distributed Generation Customers (estimated as per cent of new connections met on-time). Beginning in 2028, Hydro One will change the methodology to measure customer satisfaction of Hydro One's main customer groups (residential and small business customers, commercial and industrial customers, and large distribution accounts) to capture more data points and feedback that is actionable.

HISTORICAL PERFORMANCE AND VARIANCE TO 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Customer Satisfaction Index	82.4%	82.4%	82.1%	85.7%	85.0%	▲			85.0%	85.0%	86.0%

Historically, Hydro One's Customer Satisfaction Index has trended positively, averaging 84% over the past five years. The 2025 target was missed due to temporary, external factors that affected customer experience. Specifically, the Canada Post strike disrupted the timely delivery of paper bills and customer correspondence, leading to increased billing inquiries and dissatisfaction among customers who rely on mail-based communications. In addition, temporary issues with the myAccount platform affected customers' ability to access account information, view bills, and complete transactions online, which negatively impacted satisfaction during the affected period.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Customer Satisfaction Index			86.0%	87.0%	82.0%	82.0%	82.0%	82.0%	82.0%

Hydro One is updating its Customer Satisfaction Index (CSI) methodology beginning in 2028 to measure satisfaction across its main customer groups. The new CSI metric will be a composite index comprised of overall customer satisfaction results from (1) residential and small business customers and (2) commercial, industrial, and large distribution accounts, weighted to produce a single overall measure of customer satisfaction. This change replaces the previous seven component composite index that was a mix of post-transactional surveys and compliance measures, which limited the ability to clearly identify drivers of satisfaction across different customer segments. By shifting to a customer segment-based approach, the new methodology will capture the perceptions of the broader customer base, not only those who have completed a transaction, providing a more representative and holistic view of the customer experience.

These results, alongside call reviews, voice of customer inputs and related interactions, will be analyzed to identify emerging issues and areas requiring attention, strengthening Hydro One's ability to prioritize improvements, allocate resources where they deliver the greatest value, and monitor outcomes over time. The enhanced metric improves transparency while positioning Hydro One to respond more effectively to evolving customer expectations and service demands.

As a result of the updated methodology, new targets have been established for the Customer Satisfaction Index metric. Under the new methodology, historical values of this metric would have been 82% in 2024, and 82% in 2025. Based on this, Hydro One is targeting 82% for this metric for all years through the 2028 to 2032 rate period. Though this target is lower than the previous targets, these adjustments represent a reset of baseline measurements associated with the change in methodology and should not be interpreted as a decline in underlying service quality.

Witness: Gianni DiFilippo; Spencer Gill; Aimee Oabel

3.5.2.4 OPERATIONAL EFFECTIVENESS MEASURES

3.5.2.5 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.

3.5.2.5.1 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 when a vehicle contacts wires.

HISTORICAL PERFORMANCE AND VARIANCE TO 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Level of Public awareness	78.00%	81.00%	81.00%	82.00%	82.00%	▲			80.0%	80.0%	80.0%

The level of public awareness has trended upward over the prior five years.

Hydro One's overall public safety awareness index score was 82% in the most recent survey conducted in 2024. 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.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Level of Public awareness			80%	80%	80%	80%	80%	80%	80%

Witness: Gianni DiFilippo; Spencer Gill; Aimee Oabel

Scores of 80% are expected to remain into the future. The 2026 campaign will focus on increasing awareness of electrical hazards and reducing preventable incidents across Ontario, by empowering the public with the knowledge they need to stay safe around electricity at home, at work, and in their communities. The 2026 campaigns will leverage historical data to create targeted and seasonally relevant campaigns.

3.5.2.5.2 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.

All licensed Distributors in Ontario must be compliant with Ontario Regulation 22/04 as a condition for their OEB distributor license. The Electrical Safety Authority (ESA) is the governing authority for the regulation and has several mechanisms to assess a Distributor's compliance. Distributors are required to be audited by an external party on an annual basis on the design, construction, and maintenance of distribution systems in accordance with the regulation. A final report by the external auditor, along with a signed declaration of compliance with the regulation by an officer of the company for all sections that are not covered by the audit, is provided to the ESA. The ESA also completes due diligence inspections & compliance reviews. 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 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	►		C	C	C	C

Hydro One has received a “Compliant” rating from ESA for 2021-2025.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
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.

3.5.2.5.3 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. 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 or force majeure).

HISTORICAL PERFORMANCE AND VARIANCE TO 2023-2025 TARGETS

								OEB Targets 2025		Hydro One Targets		
Measure		2021	2022	2023	2024	2025	Trend	Industry	Distributor	2023	2024	2025
Serious Electrical Incident Index	Number of General Public Incidents	15	40	48	28	127	▲		23			
	Rate per 10, 100, 1000km of line	0.120	0.321	0.385	0.223	1.009	▲		0.183			

The OEB scorecard of serious electrical incidents is based on the previous year's incidents. For example, the 2025 scorecard number of incidents is the number of reportable incidents in the 2024 calendar year.

For 2025, the ESA identified 127 incidents that met the serious electrical incident criteria (actual or potential electrical contact**).** These 127 incidents reflect a change in Hydro One's internal reporting process, triggered by compliance reviews by ESA for certain incidents and an update of clarifications to ESA's Section 12 distributor guideline. As a result of the review and clarifications, Hydro One takes a more conservative approach in identifying public incidents to the ESA. Prior to 2024, certain scenarios, such as a tree falling in a remote field and bringing down a power line where there was no reasonable risk of public contact, would not be reported to the ESA. In order to more comprehensively and conservatively align with ESA guidance, these types of events are now being reported, which has resulted in an increase in the number of reported incidents.

Of the 127 incidents, 92 incidents were downed power lines as a result of falling vegetation where there were no members of the general public and no electrical contact was made by members of the public. However, these incidents met the reporting criteria of ESA's Section 12 Distributor Guideline on reporting Serious Electrical Incidents. As described further in Exhibit E-03-02 and DSP Section 3.2, Forestry is introducing a new OCP Flex strategy which aims to target more specific, higher risk spans which may help to mitigate the volume of tree related incidents. This program will be monitored under the new KM of Lines Managed metric as described in 3.5.3.3.6.

Witness: Gianni DiFilippo; Spencer Gill; Aimee Oabel

For 2025, 4 of the 127 incidents resulted in a critical injury or fatality. In all 4 cases a member of the public encroached on or made contact with a line that was otherwise adequately barriered. All other 123 of 127 incidents were reportable because they were deemed to have the "potential to cause injury or death" per the ESA's Section 12 guideline on reporting serious electrical incidents.

TARGETS FOR THE 2026-2032 PERIOD

		OEB Targets 2025		Hydro One Targets						
Measures		**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Serious Electrical Incident Index	Number of General Public Incidents		23							
	Rate per 10, 100, 1000km of line		0.183							

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 2025, Hydro One has a target of 23 incidents from the ESA. As noted in introduction section this exhibit, targets for 2027 were set in the last distribution application are maintained as filed previously.

3.5.2.6 SYSTEM RELIABILITY

Hydro One tracks and measures the reliability of its electricity distribution system using two industry-standard indicators:

1. Distribution System Average Interruption Duration Index (D-SAIDI), which measures the average duration of sustained interruptions experienced by customers; and
2. Distribution System Average Interruption Frequency Index (D-SAIFI), which measures the average number of sustained interruptions experienced by customers.

OEB Mandated Changes

The OEB has implemented changes in reliability reporting methodologies as described below. As a result of these changes, direct year-over-year comparisons are not always on a fully equivalent basis. Where reporting methodologies have changed, Hydro One has identified and explained the impacts on reported results to provide appropriate context for performance trends.

IEEE 1366 Major Event Days

Consistent with industry practice and OEB guidance, Hydro One excludes extreme, non-routine, and uncontrollable utility outages from reported distribution reliability results. On March 2, 2023, and in relation to the proceeding EB-2021-0301, the OEB issued a letter titled “Amendments to Reporting and Record-keeping Requirements”. As a result of the guidance in this letter HONI adopted the IEEE 1366 Major Event Day (“MED”) methodology, commonly referred to as the 2.5 beta exclusion method, for the identification and exclusion of such events. Prior to 2023, Hydro One applied a force majeure approach under which an event was considered extraordinary when it caused interruptions affecting 10% or more of Hydro One customers.

Under the IEEE 1366 methodology, a day is classified as a Major Event Day when its daily D-SAIDI value exceeds a statistically derived threshold based on a rolling five-year history of system performance. The methodology is designed to identify and exclude infrequent, extreme events, such as severe storms and other extraordinary circumstances, that are outside normal utility operations. Excluding these events enables more meaningful year-over-year comparisons of underlying system reliability performance.

Adverse Weather Cause Codes

In the OEB letter dated November 21, 2022 “Notice of Amendments to RRR 2.1.4.2 System Reliability”, distributors were required to report on all 10 primary cause codes including ‘adverse weather’ cause code starting in 2023, and further required outages to be captured and reported under the sub-categories starting in 2024; for ‘Adverse Weather’ primary cause code, sub-categories of ‘Tree Contacts due to adverse weather’, ‘Equipment Breakage due to adverse weather’, and ‘Other Adverse Weather’ exist. These

subcategories are included within the total SAIDI and SAIFI results presented in Figures 2 and 3. To improve transparency, the adverse weather-related impacts have been visually highlighted and separately identified within the charts, while remaining part of the overall reliability results.

Hydro One Storm Days

Hydro One internally tracks Storm Days, which are significant weather-related events that do not meet the IEEE 1366 criteria for classification as a Major Event Day. While D-SAIDI from Major Event Days is excluded, Storm Days are included in Hydro One's reported D-SAIDI and D-SAIFI results and can have a material impact on annual reliability performance.

A day is classified as a Storm Day when both of the following criteria are met:

1. 150 or more customer interruptions occur, or more than 3% of customers are interrupted; and
2. There is evidence of storm activity, supported by sources such as Environment Canada weather data, other meteorological information, field reports, or reports from Hydro One's Integrated System Operating Centre ("ISOC").

Storm Days are tracked by Hydro One for internal monitoring and analysis of weather-related impacts on system reliability.

3.5.2.6.1 DISTRIBUTION SAIDI

Performance Category	Measure	Description
System Reliability	SAIDI - 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 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
D-SAIDI[4]	6.5	6.9	7.5	7.7	8.2	▲		4.3	4.7	4.4	4.3

[4] Beginning in 2023, Hydro One adopted the IEEE 1366 Major Event Day (MED) methodology (2.5 beta exclusion method) for identifying and excluding extreme, non-routine outage events from reliability metrics, consistent with OEB reporting requirements. Prior to 2023, Hydro One applied a force majeure approach based on a fixed customer interruption threshold.

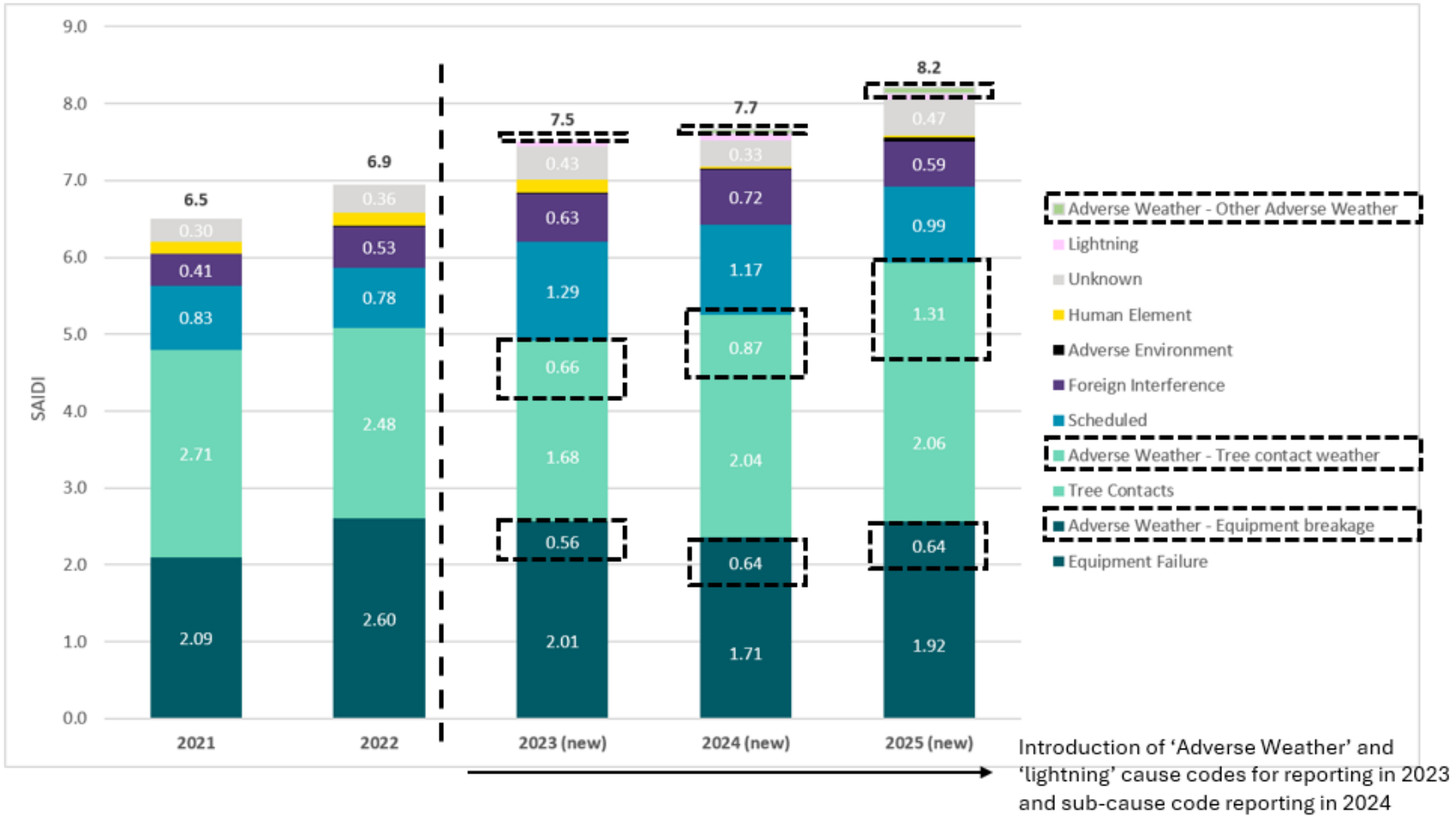


Figure 2: Distribution SAIDI Contribution by OEB Causes

Hydro One's reported D-SAIDI increased from 6.5 hours in 2021 to 8.2 hours in 2025, indicating that customers experienced longer average outage durations over the period. The 2025 outages are primarily due to tree contacts and equipment failure events impacted by a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year. As mentioned in DSP Section 3.7, subsection 3.7.2.4 “Shift in Climate”, Hydro One's distribution system now experiences approximately 40 storm days annually on average, representing a sustained increase relative to historical levels. While year-to-year performance is influenced by weather and operating conditions, the longer-term trend reflects increasing and consistently high contributions from tree contacts and equipment failures respectively, which together represent the largest contributors to D-SAIDI throughout the 2021-2025 period.

As shown in Figure 2 above, equipment failure continued to be a significant driver to D-SAIDI, contributing between 2.1 and 2.6 hours annually over the 2023-2025 period when the equipment impact from “Adverse Weather” cause code is included. Tree-related outages remained the largest individual contributor of interruption duration. Combined tree-related contributions increased from approximately 2.7 hours in 2021 to approximately 3.4 hours in 2025 when the tree contact impact from “Adverse Weather” cause code is included, reflecting both outages directly attributed to tree contacts and tree-related interruptions captured under the adverse weather category following changes to OEB outage reporting requirements.

As described within DSP Section 3.1 and Section 3.7, as well as Exhibit E-03-02, Hydro One deferred certain planned OM&A and system renewal investments during the period to address non-discretionary customer-driven obligations and other emergent system needs, including sustained load growth, increased customer connections, DER integration requirements, and responses to extreme weather events, contributing to the deterioration of reliability performance and performance remaining above target levels during the period. The performance trend over the period reflects both increasing asset-related outage drivers associated with aging infrastructure and asset degradation and the challenges associated with maintaining reliability performance while responding to significant growth

in demand-driven capital programs. In addition, vegetation-related reliability performance deteriorated beginning in 2023 as vegetation management execution declined due to unanticipated levels of overgrown vegetation and the reprioritization of resources to address emergent demand-driven work. The continued contribution of equipment failures and tree-related outages demonstrates the importance of sustained investments in asset renewal, vegetation management, and system maintenance activities to improve reliability performance over the long term.

TARGETS

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
D-SAIDI	N/A	4.3	7.8	7.7	7.6	7.5	7.4	7.3	7.2
D-SAIDI (EB-2021-0110)			4.3	4.2					

The 2028-2032 reliability targets were established using the target-setting methodology set out in OEB File No. EB-2021-0307. The targets are based on reliability performance data from 2021 to 2025 and incorporate an annual 1.5% improvement factor, consistent with the OEB's October 3, 2025 letter “Reliability Performance Targets Released for Electricity Distributors”. To support consistent reporting and comparison across the forecast period, Hydro One has also restated the 2026 and 2027 D-SAIDI targets using the same EB-2021-0307 methodology that leverages reliability performance data from 2021 to 2025.

Hydro One is investing in the following programs that are expected to help manage reliability risks, and over time, impact reliability performance: Distribution Automation & Sectionalization Program (DSP Section 3.11, D-SS-05), Distribution Station Renewal program (DSP Section 3.11, D-SR-04), Pole Sustainment Program (DSP Section 3.11, D-SR-07), Selective Undergrounding (DSP Section 3.11, D-SR-14), Reliability Improvement Program (DSP Section 3.11, D-SS-02), Energy Storage Solutions (DSP Section 3.11, D-SS-04), the Advanced Distribution Management System (DSP Section 3.11, D-SS-09), and planned maintenance programs including Defect Corrections and Vegetation

Management (Exhibit E-03-02). Due to the volume of poor condition assets at an increased risk of failure and deteriorating right of way conditions there will be a lag between the resumption of the planned renewal and maintenance programs and a positive impact on both SAIDI and SAIFI measures.

3.5.2.6.2 DISTRIBUTION SAIFI

Performance Category	Measure	Description
System Reliability	SAIFI - 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 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
D-SAIFI[5]	2.4	2.5	2.8	2.7	2.9	▲	N/A	1.9	2.1	2.0	1.9

[5] Beginning in 2023, Hydro One adopted the IEEE 1366 Major Event Day (MED) methodology (2.5 beta exclusion method) for identifying and excluding extreme, non-routine outage events from reliability metrics, consistent with OEB reporting requirements. Prior to 2023, Hydro One applied a force majeure approach based on a fixed customer interruption threshold.

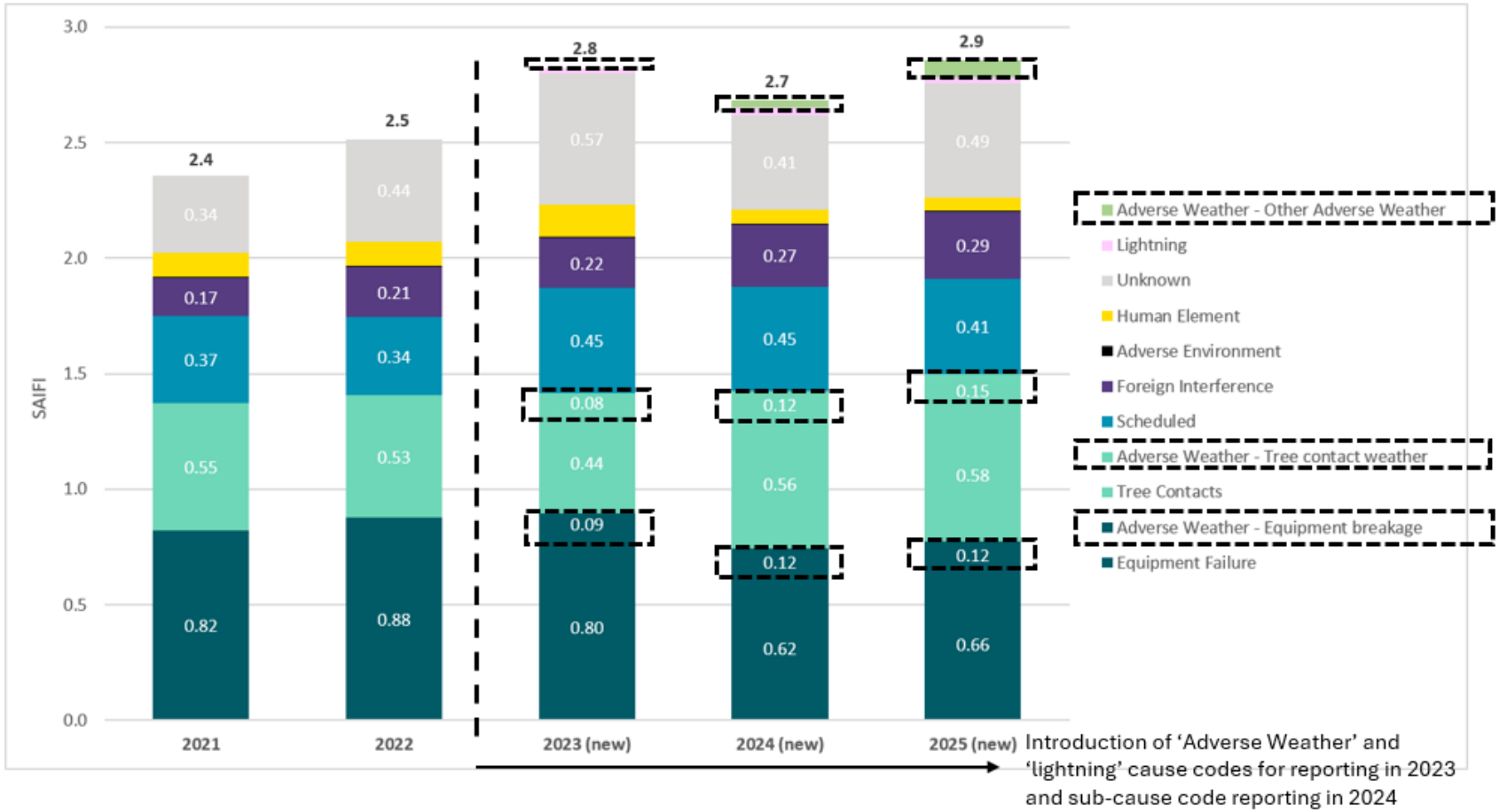


Figure 3: SAIFI Contribution by OEB Causes

Hydro One's reported D-SAIFI increased from 2.4 interruptions per customer in 2021 to 2.9 interruptions per customer in 2025, indicating that customers experienced interruptions more frequently over the 2021-2025 period.

As shown in Figure 3, equipment failures and tree-related outages were the largest contributors to D-SAIFI throughout the period. Tree contacts and equipment failures consistently accounted for the majority of customer interruptions, with outage frequency further affected by a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36. As mentioned DSP Section 3.7, subsection 3.7.2.4 “Shift in Climate”, Hydro One's distribution system now experiences approximately 40 storm days annually on average, representing a sustained increase relative to historical levels. Equipment-related outages reflect the ongoing challenges associated with an aging asset base, while tree-related outages remained a significant source of customer interruptions over the period. Together, these causes largely explain the increase in D-SAIFI between 2021 and 2025. The trend reflects the combined impacts of aging infrastructure, vegetation-related contacts, and limitations on Hydro One's ability to fully address these risks through its capital and maintenance programs.

As described within DSP Section 3.1 and Section 3.7, as well as Exhibit E-03-02, Hydro One deferred certain planned OM&A and system renewal investments during the period as resources and capital were prioritized to address growing customer demand for connection and development-related work and increased expenditures related to storms, the deterioration of reliability performance and performance remaining above target levels during the period. The performance trend over the period reflects both increasing asset-related outage drivers and the challenges associated with maintaining reliability performance while responding to significant growth in demand-driven capital programs. The continued contribution of equipment failures and tree-related outages demonstrates the importance of sustained investments in asset renewal, vegetation management, and system maintenance activities to improve reliability performance over the long term.

TARGETS

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
D-SAIFI	N/A	1.9	2.7	2.7	2.7	2.7	2.7	2.7	2.7
D-SAIFI (EB-2021-0110)			1.9	1.8					

The 2028-2032 reliability targets were established using the target-setting methodology set out in OEB File No. EB-2021-0307. The targets are based on reliability performance data from 2021 to 2025 and incorporate an annual 0.25% improvement factor, consistent with the OEB's October 3, 2025 letter “Reliability Performance Targets Released for Electricity Distributors”. To support consistent reporting and comparison across the forecast period, Hydro One has also restated the 2026 and 2027 D-SAIFI targets using the same EB-2021-0307 methodology that leverages reliability performance data from 2021 to 2025.

Hydro One is investing in the following programs that are expected to manage reliability risks, and over time, impact reliability performance: Distribution Automation & Sectionalization Program (DSP Section 3.11, D-SS-05), Distribution Station Renewal program (DSP Section 3.11, D-SR-04), Pole Sustainment Program (DSP Section 3.11, D-SR-07), Selective Undergrounding (DSP Section 3.11, D-SR-14), Reliability Improvement Program (DSP Section 3.11, D-SS-02), Energy Storage Solutions (DSP Section 3.11, D-SS-04), the Advanced Distribution Management System (DSP Section 3.11, D-SS-09), and planned maintenance programs including Defect Corrections and Vegetation Management (Exhibit E-3-2). Due to the volume of poor condition assets at an increased risk of failure and deteriorating right of way conditions there will be a lag between the resumption of the planned replacement programs and maintenance programs and a positive impact on both SAIDI and SAIFI measures.

3.5.2.7 ASSET MANAGEMENT

3.5.2.7.1 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 2023-2025 TARGETS

							OEB Target		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Distribution System Plan Implementation Progress	100.90%	126.03%	101.17%	105.30%	111.78%	▲			100%	100%	100%

Performance over the 2021 to 2025 period has averaged 109%, with year-over-year variation due to customer and demand work, including new customer connections, storm and trouble response, and third-party joint use and relocations. Performance in 2022 and 2025 were also impacted by severe weather events.

Performance in 2022 was impacted by a severe weather system "Derecho", which swept through the southern parts of the province on May 21st, 2022. A Derecho is a downburst storm characterized by lines of intense, widespread, and fast-moving systems. The Derecho swept across the Central, Southern and Eastern regions of Ontario with torrential rainfall, hail, frequent lightning, tornados and wind gusts of up to 130km/h that downed large volume of trees and caused significant damage to both Hydro One's assets, requiring extensive restoration and rebuild, resulting in net restoration costs of $109.3M.

Performance in 2025 was impacted by a significant spring ice storm, a major storm system that caused extensive damage to Hydro One's distribution infrastructure, as accumulated ice brought down trees, poles, and conductors across much of the company's service

territory, resulting in net restoration costs of $196.2M. This was the most damaging weather event Hydro One has experienced since its incorporation in 1999 and placed significant upwards pressure on the 2025 implementation plan.

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Distribution System Plan Implementation Progress			100%	100%	100%	100%	100%	100%	100%

Targets for the 2028 to 2032 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.

3.5.2.8 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 proprietary 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.

3.5.2.8.1 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 2023-2025 TARGETS

							OEB Targets 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Efficiency Assessment	4	4	4	4	4	►			4	4	4

For the 2021 to 2025 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 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Efficiency Assessment			4	4					

Hydro One is not proposing a target for the Efficiency Assessment metric for the 2028-2032 period. As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One has proposed to establish its Stretch Factor using the Clearspring research rather than the PEG model that underpins the OEB's Efficiency Assessment metric. Accordingly, Hydro One has not established a target for this metric. Hydro One will continue to report on the Efficiency Assessment metric in accordance with the OEB's scorecard requirements.

3.5.2.8.2 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 2025		Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Total Cost per Customer	$1,033	$1,172	$1,369	$1,384	$1,399	▲					

Hydro One's total cost per customer, as measured by PEG, has averaged $1,271 from 2021-2025.

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. In 2025, the Business's Annual Total Cost per Customer equaled $1,399, an increase of $15 per customer or +1.1% from 2024.

3.5.2.8.3 TOTAL COST PER KM 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 2025		Hydro One Targets		
Measures	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
Total Cost per km of Line	$11,940	$13,537	$15,970	$16,326	$16,558	▲	N/A	N/A	N/A	N/A	N/A

The average total cost per km of line as measured by PEG, has averaged $14,866 from 2021-2025.

The Total Cost per KM of Line is defined as the total Capital and OM&A costs, divided by the total number of kms of line operated to serve customers, along with certain PEG prescribed adjustments. In 2025, the Business's Total Cost per KM of Line equaled $16,558, an increase of $232 per km or +1.4% from 2024.

3.5.2.9 PUBLIC POLICY RESPONSIVENESS MEASURES

3.5.2.10 CONNECTION OF RENEWABLE GENERATION

3.5.2.10.1 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 prior to May 2026, or 12kW from May 2026 on) 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 2023-2025 TARGETS

							OEB Target		Hydro One Target		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**Industry**	**Distributor**	**2023**	**2024**	**2025**
New Micro-embedded Generation Facilities Connected On Time	98.72%	96.63%	90.00%	90.67%	92.30%	▼	90.00%		98.00%	98.00%	98.00%

On-time connection of micro-embedded facilities has trended slightly downward, averaging 93.7% over 2021-2025 period.

In 2025, Hydro One achieved a 92.3% on-time rate for connecting new micro-embedded generation facilities meeting the industry target of 90% for the thirteenth consecutive year. Over the 2021 to 2025 period, while Hydro One exceeded the industry target for connecting new micro-embedded generation facilities, the distributor target was missed with 2021 being the last year it was achieved. The decline was primarily attributable to field resource limitations and isolated instances of human error. In 2025, we implemented enhanced reporting to provide Field Business Centres along with monthly reviews to identify any systemic issues, monitor performance trends and drive target improvements in the target years.

Witness: Gianni DiFilippo; Spencer Gill; Aimee Oabel

TARGETS FOR THE 2026-2032 PERIOD

	OEB Targets 2025		Hydro One Targets						
Measures	**Industry**	**Distributor**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
New Micro-embedded Generation Facilities Connected On Time	90.00%	N/A	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%

Over the term of the Application, Hydro One plans to maintain the distributor target at 98%. Hydro One expects to meet its internal target through refined processes, introducing workflow automation, improved work notifications and instructions and ensuring field staff have clear expectations and timely information.

3.5.2.11 FINANCIAL PERFORMANCE

Hydro One does not forecast targets for the financial performance measures. The basis for the 2021-2025 results is the data submitted as part of the annual RRR submissions.

3.5.2.12 FINANCIAL RATIOS

3.5.2.12.1 LIQUIDITY: CURRENT RATIO (CURRENT ASSETS/CURRENT LIABILITIES)

Performance Category	Measure	Description
Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Liquidity is measured as the ratio of the current assets to current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year. Current liabilities are defined as short term debts or financial obligations that become due within the year.

HISTORICAL PERFORMANCE

Measures	2021	2022	2023	2024	2025
Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.64	0.50	0.55	0.53	0.59

The current ratio for 2025 was reported as 0.59, which was consistent with all prior years except for 2021 where there was a reduction in the inter-company demand facility due

within one year. The 2025 result indicates that for every one dollar of current liabilities, Hydro One had $0.59 in current assets.

Please refer to Exhibit A-06-02 for more information on Hydro One Distribution's financial information.

3.5.2.12.2 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	2021	2022	2023	2024	2025
Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.72	1.63	1.84	1.99	2.08

For 2025, the debt-to-equity ratio was recorded as 2.08, higher than all prior years. This increase in leverage is primarily attributable to higher long-term debt.

Please refer to Exhibit A-06-02 for more information on Hydro One Distribution's financial information.

3.5.2.12.3 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 annual RRR filing.

HISTORICAL PERFORMANCE AND VARIANCE TO 2021-2025 DEEMED RETURN ON EQUITY

Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.00%	9.00%	9.36%	9.36%	9.36%
	Achieved	10.99%	10.10%	10.88%	9.79%	11.38%

For the year 2025, the Business achieved a regulatory return on equity (ROE) of 11.38%. The 2025 ROE was 2.02% higher than the deemed ROE of 9.36%. The Achieved ROE was higher than deemed in 2025 primarily due to increased revenues associated with higher energy consumption, and the increased number of customer connections.

3.5.3 HYDRO ONE DISTRIBUTION OEB SCORECARD

In the EB-2021-0110 rate application, Hydro One filed its Distribution OEB scorecard along with targets up to 2027 and actuals for 2020.

Hydro One has made the following additions to the Distribution Scorecard. Supporting details for these proposals are provided below on a metric-by-metric basis:

- Added a metric for Kilometers of Forestry Managed
- Added a metric to measure the Distribution Capital Program Work Composite Index (DCAI)
- Added a metric for Flexibility & Local Energy Efficiency Programs
- Added a metric to Enabling Remote Operable Capabilities
- Added a metric for Load Capacity Constrained Distribution Stations

RRFE Outcomes		Measure	2021	2022	2023	2024	2025	Trend	Hydro One Targets 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction	89%	87%	87%	88%	88%	▼	87%	87%	87%	87%	87%	82%	82%	82%	82%	82%
		Handling of Unplanned Outages Satisfaction[6]	78%	78%	78%	79%	80%	▲	80%	81%	82%	82%	83%	83%	83%	83%	83%	83%
		Call Centre Customer Satisfaction %	86%	86%	84%	86%	84%	▼	86%	86%	86%	86%	86%	80%	80%	80%	80%	80%
		myAccount Customer Satisfaction %[7]	60%	67%	68%	72%	66%	▲	66%	67%	68%	69%	70%	70%	70%	71%	71%	72%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit $	$11,158	$13,133	$15,216	$19,477	$18,191	▲	$10,608	$10,818	$11,032	$11,250	$11,473	$16,218	$16,837	$17,494	$18,181	$18,893
		Vegetation Management - Gross Defect Correction (OCP/OCP Flex) Cost per km $[8]	$4,019	$5,070	$ 6,996	$8,026	$8,580	▲	$3,824	$3,901	$3,980	$4,060	$4,140	$7,484	$7,633	$7,786	$7,914	$8,053
		Station Renewal - Gross Cost per MVA in $	$356,899	$655,244	No project in-serviced	$818,524	$917,979	▲	$425,000	$423,000	$421,000	$419,000	$417,000	$654,773	$667,869	$681,226	$694,850	$708,747
		OM&A dollars per customer	$409	$461	$459	$474	$419	▲	$416	$418	$469	$453	$462	$626	-	-	-	-
		OM&A dollars per km of line	$4,779	$5,441	$5,469	$5,709	$5,058	▲	$4,798	$4,838	$5,393	$5,506	$5,631	$7,650	-	-	-	-
		KM of Forestry Managed	New Metric											15,833	15,833	15,833	15,833	15,833
		DCAI	New Metric											100%	100%	100%	100%	100%
	System Reliability	SAIDI for Equipment Caused Interruptions	2.1	2.6	2.0	1.7	1.9	▼	1.7	1.6	1.5	1.9	1.9	1.9	1.8	1.8	1.8	1.8
		SAIDI for Vegetation Caused Interruptions	2.7	2.5	1.7	2.0	2.1	▼	1.9	1.7	1.7	2.0	2.0	2.0	1.9	1.9	1.8	1.8
		SAIDI - Rural - duration in hours	7.5	8.0	8.8	9.2	10.0	▲	5.2	4.8	4.7	9.6	9.5	9.4	9.3	9.1	9.0	8.9
		SAIFI - Rural - frequency of outages	2.6	2.8	3.2	3.1	3.3	▲	2.3	2.1	2.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1
		SAIDI - Urban - duration in hours	2.8	2.8	3.5	3.1	2.9	▲	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	1.4	1.3	1.6	1.5	1.6	▲	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
		Interruptions per LDA	1.3	1.5	1.7	1.3	1.2	▼	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
		Flexibility & Local Energy Efficiency Programs	New Metric											56,600	65,200	71,900	77,100	81,300
		Enabling Remote Operable Capabilities	New Metric											90% of M-class feeders by the end of 2032				
		Load Capacity Constrained Distribution Stations	New Metric											0-4% by the end of 2032				

Figure 4: Hydro One Distribution OEB Scorecard

[6] As described in the sections that follow, the methodology for this measure was changed in 2020.
[7] Ibid.
[8] This measure is being renamed from Gross Cyclical Cost per km $ to better reflect tracking of the OCP/OCP Flex program costs. There are no changes to the calculation methodology.

3.5.3.1 CUSTOMER FOCUS MEASURES

3.5.3.2 CUSTOMER SATISFACTION

3.5.3.2.1 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
Small Business and Residential Satisfaction (%)	89%	87%	87%	88%	88%	▼	87%	87%	87%

Small business and residential customer satisfaction has averaged 88% over the last five years, meeting or exceeding target in all years from 2023-2025.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Small Business and Residential Satisfaction (%)	87%	87%	82%	82%	82%	82%	82%

The small business and residential satisfaction score is currently reported from the telephone Residential and Small Business ("R&SB") customer satisfaction survey. Hydro One plans to transition to an online survey by 2028. This change will result in improved cost efficiency, larger and more timely sample sizes, and greater reach across diverse customer groups.

Before implementing a change in survey methodology, Hydro One conducts concurrent surveys using both the existing and proposed methodologies to establish a baseline for future measurement. Historical results from the concurrent online R&SB customer satisfaction survey, available since 2024, were 81% in 2024 and 82% in 2025. During the same period, telephone survey scores for the same customer segment were 88%. The difference between the telephone and online results is expected to reflect the impact of survey methodology, as the surveys were conducted concurrently among the same customer segment. As a result, Hydro One is proposing a target of 82% for this metric for each year of the 2028 to 2032 rate period. While the proposed target for online results is lower than the previous target established using telephone survey results, the reduction reflects the adoption of a new survey methodology and the corresponding establishment of a new performance baseline. The proposed 82% target is supported by the available historical results from the online survey and provides a stable and evidence-based benchmark for assessing customer satisfaction over the rate period.

3.5.3.2.2 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.

HISTORICAL PERFORMANCE AND VARIANCE TO 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
Handling of Unplanned Outages Satisfaction %	78%	78%	78%	79%	80%	▲	80%	81%	82%

Customer satisfaction with unplanned outages has improved over the past five years, averaging 79%. In 2025, 80% of customers were satisfied with the way Hydro One handled unplanned outages, slightly below the target of 82%.

Effective outage communication is a key driver of overall customer satisfaction. While the reach of outage communications has increased over time, a notable portion of customers continue to receive no outage notifications, primarily due to lack of alert service enrollment. For customers who do receive notifications, the accuracy of Estimated Time of Restoration (ETR) information and the consistency of restoration updates remain key concerns. Frequent ETR revisions or unclear messaging during outages contribute to customer frustration and reduced confidence. Text messaging has become the preferred communication channel; however, improvements are needed to increase customer enrollment and to enhance the timing of initial and follow-up notifications during outages.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Handling of Unplanned Outages Satisfaction %	82%	83%	83%	83%	83%	83%	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.

3.5.3.2.3 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
Call Centre Customer Satisfaction %	86%	86%	84%	86%	84%	▼	86%	86%	86%

Call centre customer satisfaction has been consistent over the past five years, averaging 85% which is 1 percentage point below Hydro One's internal targets for 2023 to 2025. Hydro One has identified a number of reasons for this result:

Hydro One's investments in digital and self-service channels have enabled more customers to complete simple, routine transactions online or through the Interactive Voice Response (IVR) system. As a result, the calls that continue to be handled by Customer Service Representatives increasingly involve more complex issues that require additional time to assess and resolve. This shift in call mix contributes to longer interaction and wait times, which can affect the overall customer experience, particularly during periods of high call volumes.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Call Centre Customer Satisfaction %	86%	86%	80%	80%	80%	80%	80%

The Call Centre customer satisfaction score is currently reported from the telephone-based Call Centre satisfaction survey. Hydro One is planning to move this survey to an online mode by 2028. This change in mode brings several benefits, including significantly improved cost efficiency, larger and more timely sample sizes, and greater reach across diverse customer groups.

While equivalent historical scores for this metric from an online Call Centre satisfaction survey are not yet available, online survey results are generally lower than those obtained through telephone surveys. Hydro One is targeting 80% for this metric for all years through the 2028 to 2032 rate period. This target recognizes the move to online mode and recognizing that the concurrent replacement of the Customer Information System (CIS) and integration of the AMI2.0 meters into Hydro One's billing system is likely to increase the number and complexity of calls to the call centre.

3.5.3.2.4 MYACCOUNT CUSTOMER SATISFACTION

Performance Category	Measure	Description
Customer Satisfaction	myAccount Customer Satisfaction	This metric 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
myAccount Customer Satisfaction %	60%	67%	68%	72%	66%	▲	66%	67%	68%

Customer satisfaction with myAccount has trended upwards over the past five years, averaging 67%. Between 2022 and 2024, customer satisfaction levels have increased and exceeded targets. Hydro One has implemented targeted enhancements to its customer service tools and digital platforms to reduce customer effort, improve clarity, and support timely issue resolution. Key changes include simplifying high-volume processes such as

password resets, improving visibility into account registration and access, and clarifying authorization for customers acting on behalf of others.

In 2025, customer satisfaction with the myAccount portal fell 2 percent below the target of 68 percent. Customers cited performance, navigation, bill viewing and login functionality as the main reasons for low satisfaction with the myAccount portal. Hydro One is using these insights to prioritize enhancements aimed at improving usability and reliability, with the objective of strengthening customer experience and improving satisfaction outcomes in future years.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
myAccount Customer Satisfaction %	69%	70%	70%	70%	71%	71%	72%

Customer expectations for digital services continue to increase, informed by experiences with other service providers and their digital solutions. Subject to adequate funding for the Customer Digital Experience and Customer Care programs, Hydro One is committed to ongoing enhancements of the myAccount portal over the test years to support strong performance.

3.5.3.3 OPERATIONAL EFFECTIVENESS MEASURES

3.5.3.4 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.

3.5.3.4.1 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
Pole Replacement - Gross Cost Per Unit in $	$11,158	$13,133	$15,216	$19,477	$18,191	▲	$10,608	$10,818	$11,032

Hydro One's higher pole replacement unit costs over the 2021–2025 period is due to three primary factors: (1) increased complexity driven by the Risk Spend Efficiency (RSE) approach, (2) program ramp-down and redirection of work, and (3) the use of external contractors to manage overall work volumes.

The RSE approach, introduced in 2019, prioritizes the replacement of the highest-risk poles. This has shifted work toward more complex installations, including higher-voltage and multi-phase configurations, structures serving more customers per pole, and installations requiring composite poles and rock settings. These factors have increased design effort, construction time, and overall unit costs.

Unit costs were also impacted by the ramp-down and deferral of portions of the pole replacement program over the period. Work was redirected to address higher-priority system needs, including activities required to maintain system safety and reliability. While field execution volumes fluctuated, design, permitting, and preparatory work continued, resulting in higher unit costs during periods of lower output. This redirection of resources contributed to upward pressure on unit costs.

External contractors were utilized to support high work volumes across Hydro One's distribution business during the rate period. Contractor unit costs are higher than internal execution, contributing to overall cost increases. These impacts were more pronounced

in 2024 and 2025, as Hydro One observed and responded to higher-than-expected contractor pricing and subsequently reduced contractor reliance. In 2025, contractor costs decreased compared to 2024, as contractors were given more geographically concentrated work (e.g.,Peterborough), which improved efficiency. Internal labour unit costs remained relatively stable over the period.

Overall, the increase in unit costs reflects the deliberate prioritization of higher-risk assets, program reprioritization and delivery constraints, and the use of external resources to meet workload demands.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Pole Replacement – Gross Cost Per Unit in $	$11,250	$11,473	$16,218	$16,837	$17,494	$18,181	$18,893

The targets for the 2028 to 2032 period were based on the 2028 estimated unit cost for the pole replacement investment, increased by inflation and incorporates efficiencies described in the SPF Section 1.4 as well as expected benefits from the implementation of a clustered replacement approach for areas with concentrated pole condition needs. This approach will coordinate execution of pole replacement work within the same feeder sections to improve productivity and reduce mobilization, planning, outage coordination, and construction costs.

3.5.3.4.2 VEGETATION MANAGEMENT – GROSS DEFECT CORRECTION (OCP FLEX) COST PER KM

Performance Category	Measure	Description
Cost Control	Vegetation Management - Gross Defect Correction (OCP Flex) Cost per km	This measure is the dollar cost per km of cyclical line managed. $= \frac{Cost\ of\ Veg\ Defect\ Correction\ Program\ (OCP\ Flex)}{KM's\ of\ Line\ managed}$

This cost per unit metric will illustrate the unit cost performance of the revised version of the Optimal Cycle Protocol (OCP Flex) vegetation management program. The OCP Flex vegetation management strategy is 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, such as the density of vegetation, equipment requirements, growth rates, the remoteness of the location, and resource mix. These factors have a significant impact on the costs related to the program which is why it is helpful to view the average cost per unit as a trend, since factors such as density change year-over-year.

HISTORICAL PERFORMANCE AND VARIANCE TO 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
Vegetation Management - Gross line clearing Cost per km $[9]	$4,019	$5,070	$6,996	$8,026	$8,580	▲	$3,824	$3,901	$3,980

As is further outlined within Exhibits E-03-02 and DSP Section 3.2, OCP was first proposed as a two-phase approach: the first cycle would condition overgrown corridors to OCP standards, and the subsequent cycles would maintain these conditions along with addressing brush.

The inability to treat the brush and apply herbicide within expected timeframes due to other high priorities within the company has resulted in growth levels nearing the limits of approach (i.e. proximity of the conductor). When brush is within proximity, it is treated as a “defect” and is executed under the OCP/OCP Flex program. In addition, brush that is within proximity requires qualified, higher paid resources (i.e. skilled arborists) to remove the top portion of the vegetation that is within proximity, which increases expenses because “topping” is typically completed in advance of brush execution, resulting in two trips to the site.

[9] 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.

Reduced brush control spending has increased defect densities in the second cycle to 60 defects per kilometer at year end 2025, compared to 26 defects per kilometer after the first cycle. The significant increase in defect densities is a direct result of unmanaged brush from previous years, now accounting for over 58% of the defect composition within OCP. In addition, part of brush treatment includes application of herbicide in the year following execution to achieve minimal regrowth, which will be incorporated into the 2028-2032 brush program.

Increased density and additional trips resulting in more time spent in the field executing work per kilometer, along with the inability to optimize resources by extending the duration of less costly and more efficient seasonal workers, resulted in fewer kilometers being completed than expected – this combination of factors contributed to the higher unit costs compared to targets.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Vegetation Management - Gross Defect Correction (OCP Flex) per km $	$4,060	$4,140	$7,484	$7,633	$7,786	$7,914	$8,053

Hydro One's vegetation management targets for cost per km cleared are represented in the above chart and align with the proposed program funding levels identified in Exhibit E-03-02. The unit costs are based on 2024 actuals and reflect the amount of brush that has grown into the line (R0s), which make up over 58% of the current defect composition and beginning in 2028 will be managed under the Dx Brush program, resulting in a reduction of the unit cost in 2028 vs. the 2025 actuals. The targets reflect a resource mix of 45% seasonal staff vs. 55% regular staff and reduced inspection costs due to the implementation of digital customer notifications.

Hydro One's vegetation management program is making improvements with respect to cost per km and full details are explained in Exhibit E-03-02. The targets for the test years are based on the information outlined in the DSP Section 3.3.

3.5.3.4.3 STATION RENEWAL– GROSS COST PER MVA IN $

Performance Category	Measure	Description
Cost Control	Station Renewal – Gross Cost per MVA in $	This cost per unit (MVA) metric will demonstrate Hydro One's unit cost performance of its station renewal projects. Every station renewal project has a unique scope of work resulting in variation in the total cost for each project. Actuals each year depends on the number of projects completed as well as the mix of solutions implemented. $ per MVA = $\frac{\text{Total Cost}* \text{ of Station Renewal Investments}}{\text{Total Stations MVA Renewal}}$

** 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
Station Renewal (Formally Station Refurb) - Gross Cost per MVA in $	$356,899	$655,244	No projects in serviced	$818,524	$917,979	▲	$425,000	$423,000	$421,000

The yearly station renewal gross cost per MVA was higher than target for 2024 and 2025. In the year 2023, no projects were in-serviced with no $/MVA to report.

The higher yearly unit cost is the result of cost pressures (on materials, labour, and design costs) and a greater ratio of higher cost station renewal projects completed across a smaller number of projects completed than projected.

Hydro One has experienced higher than anticipated materials, labour, and design costs on station renewal projects. These cost pressures are pervasive across the electricity sector as described in DSP Section 1.8. For example, the cost of transformers has unexpectedly increased on average 115% depending on the type of unit.

In EB-2021-0110 the targets were established based on a plan of 74 stations renewal projects at an average cost per MVA as defined in the 2023-2027 targets. This target assumed that 19 projects would be addressed via a Padmount Distribution Station (PDS), which is a lower cost alternative where technical requirements and load growth expectations permit. In 2022, technical issues emerged at the manufacturing level for PDS

units due to a substandard design and therefore, PDS units were no longer considered to be a deployable cost-effective alternative. As a result, a higher proportion of the non-PDS station renewal alternatives were deployed, which cost more, resulting in a higher than planned cost per MVA.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Station Refurbishments - Gross Cost per MVA in $	$419,000	$417,000	$654,773	$667,869	$681,226	$694,850	$708,747

The target for 2028-2032 includes all MVA sizes of transformers and no longer limits the metric to units less than 10MVA. This change is intended to capture and report on all renewal projects, regardless of size.

The 2028 starting point cost per MVA targets for 2028 to 2032 was developed based on the total project costs and installed MVA under SR-04. These project costs reflect more recent experience and were derived from the proposed scopes, historical and estimated unit costs which included a year-over-year inflation factor to reasonably anticipate rising costs.

3.5.3.4.4 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
OM&A dollars per customer	$409	$461	$459	$474	$419	▲	$416	$418	$469

Hydro One's average OM&A dollars per customer exceeded the target in 2023 and 2024 driven by market cost pressures, increased demand-driven work volumes, higher emergency restoration expenditures associated with extreme weather events, environmental compliance obligations, evolving security requirements, and increased spending on information technology initiatives, as further detailed in Exhibits E-03-02 and E-04-04. During this period, Hydro One made active business decisions regarding the timing and prioritization of expenditures within the overall OM&A funding available for the custom IR term, prioritizing mandatory, safety-critical, customer service, and regulatory compliance activities.

In response to these pressures, Hydro One implemented additional productivity and cost control measures, including a company-wide cost optimization program, and reduced, deferred, or re-paced certain planned work where doing so would not create unacceptable safety, reliability, compliance, or customer service risks. These actions contributed to a reduction in average cost per customer to $419 in 2025 and supported Hydro One's efforts to return cumulative OM&A spending toward the overall approved funding envelope for the five-year rate period.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
OM&A dollars per customer	$453	$462	$626	-	-	-	-

For 2028, Hydro One is targeting $626 per customer. Targets for 2028 -2032 will be set based on the OEB approved amounts determined in this Application and through the application of the Custom IR framework’s annual update applications.

3.5.3.4.5 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
OM&A dollars per km of line	$4,779	$5,441	$5,469	$5,709	$5,058	▲	$4,798	$4,838	$5,393

Hydro One's average OM&A dollars per km of line exceeded the target in 2023 and 2024 driven by market cost pressures, increased demand-driven work volumes, higher emergency restoration expenditures associated with extreme weather events, environmental compliance obligations, evolving security requirements, and increased spending on information technology initiatives, as further detailed in Exhibits E-03-02 and E-04-04. During this period, Hydro One made active business decisions regarding the timing and prioritization of expenditures within the overall OM&A funding available for the custom IR term, prioritizing mandatory, safety-critical, customer service, and regulatory compliance activities.

In response to these pressures, Hydro One implemented additional productivity and cost control measures, including a company-wide cost optimization program, and reduced, deferred, or re-paced certain planned work where doing so would not create unacceptable safety, reliability, compliance, or customer service risks. These actions contributed to a reduction in average OM&A dollars per km of line to $5,058 in 2025 and supported Hydro One's efforts to return cumulative OM&A spending toward the overall approved funding envelope for the five-year rate period.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
OM&A dollars per km of line	$5,506	$5,631	$7,650	-	-	-	-

For 2028, Hydro One is targeting $7,650 per km of line. The proposed level of OM&A is higher than historic levels, due to higher levels of sustainment OM&A to carry out planned forestry and line maintenance, as well as higher levels of IT expenditures, as described in Exhibit E-03-02 and Exhibit E-04-03. Targets for 2028-2032 will be set based on the OEB approved amounts determined in this Application and through the application of the Custom IR framework's annual update applications.

3.5.3.4.6 KM OF FORESTRY MANAGED (NEW METRIC)

Performance Category	Measure	Description
Cost Control	KM of Forestry Managed	This measure tracks the number of kilometers (km) inspected, assessed to enable targeted, risk-based prioritization of vegetation management work and confirmed to meet a risk threshold defined in the program.

This forestry metric provides a comprehensive view of program performance by (1) measuring the proportion of the system for which current vegetation condition and risk information has been collected and (2) ensuring work has been executed where required to meet a specified risk threshold. This supports data-driven prioritization of forestry activities by identifying the areas of highest vegetation-related reliability risk and ensuring that work is directed where it will provide the greatest reliability benefit. The metric also recognizes completed assessment work, even where vegetation defects are identified but not immediately addressed, reflecting the value of maintaining up-to-date system condition information and enabling a risk-based approach to forestry planning and execution.

TARGETS FOR THE 2028-2032 PERIOD

	Hydro One Targets				
Measure	**2028**	**2029**	**2030**	**2031**	**2032**
KM of Forestry Managed	15,833	15,833	15,833	15,833	15,833

Hydro One's KM of Forestry Managed targets are represented in the above chart and align with the proposed program work levels identified in Exhibit E-03-02.

3.5.3.4.7 DISTRIBUTION CAPITAL ACCOMPLISHMENT INDEX (NEW METRIC)

Performance Category	Measure	Description
Cost Control	Distribution Capital Accomplishment Index (DCAI)	The DCAI composite index measures the weighted, in-year actual performance of key Distribution System Access and System Renewal capital investments against the approved weighted budget. This metric currently covers four core programs: 1) Wood Pole Replacement, 2) Residential/Subdivision/Expansion, 3) Capital Trouble Calls for Poles & Equipment Replacement, and 4) Customer Upgrades. Together, these programs represent the primary drivers of System Access and System Renewal investments.

DCAI is a weighted composite measure that compares Hydro One's actual annual accomplishment of key Distribution System Access and System Renewal capital investments against the approved capital plan. The metric aggregates performance across a range of capital investment categories and provides an overall indication of the extent to which planned capital work was completed during the year. Hydro One is proposing to add the DCAI metric for the 2028-2032 period.

As a portfolio-level measure, the DCAI reflects Hydro One's effectiveness in delivering its distribution capital program and the approved investment plan. Performance may be influenced by changes in customer-, growth-, and emergency-driven work volumes, as well as the need to redirect funding and resources to address emergent system needs or project delivery requirements. Consequently, the metric captures both the execution of planned investments and Hydro One's ability to respond to changing operational and customer needs while delivering its overall capital program.

TARGETS FOR THE 2028-2032 PERIOD

	Hydro One Targets				
Measure	**2028**	**2029**	**2030**	**2031**	**2032**
Distribution Capital Accomplishment Index	100%	100%	100%	100%	100%

Hydro One is targeting 100% performance on DCAI for the 2028-2032 period as this represents full achievement of the approved capital program and alignment between planned and actual capital investment activity.

Witness: Gianni DiFilippo; Spencer Gill; Aimee Oabel

3.5.3.5 SYSTEM RELIABILITY

Hydro One tracks Distribution System Reliability in the OEB Electricity Distributor Scorecard using the following metrics:

- SAIDI for Equipment Caused Interruptions
- SAIDI for Vegetation Caused Interruptions
- SAIDI Rural
- SAIFI Rural
- SAIDI Urban
- SAIFI Urban
- Large Customer Interruption Frequency

3.5.3.5.1 SAIDI FOR EQUIPMENT CAUSED INTERRUPTIONS

Performance Category	Measure	Description
System Reliability	SAIDI for Equipment Caused Interruptions	This metric tracks the SAIDI impact and outcome caused by 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
SAIDI for Equipment Causes Interruptions	2.1	2.6	2.0	1.7	1.9	▼	1.7	1.6	1.5

As described in Section 3.5.2.6, distributors were required to report on all 10 primary cause codes including 'adverse weather' cause code starting in 2023. As a result, outages attributable to Equipment Failure were classified as 'Equipment Failure' cause code regardless of weather conditions in 2021 and 2022, whereas from 2023 onward, those equipment failure outages during adverse weather were reported separately under the 'adverse weather' cause code and therefore were excluded from the 'SAIDI for Equipment Caused Interruptions' results presented for 2023 to 2025.

Over the 2023-2025 period SAIDI for Equipment Caused Interruptions was higher than target. Hydro One deferred certain planned OM&A and system renewal investments during the period to address demand driven and cost pressure challenges, contributing to performance remaining above target levels. The performance trend over the historic period reflects both increasing asset-related outage drivers and the challenges associated with maintaining reliability performance while responding to significant growth in demand-driven capital programs.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
SAIDI for Equipment Caused Interruptions	1.9	1.9	1.9	1.8	1.8	1.8	1.8
SAIDI for Equipment Caused Interruptions (EB-2021-0110)	1.5	1.4					

The 2028-2032 reliability targets were established using the target-setting methodology set out in OEB File No. EB-2021-0307. The targets are based on reliability performance data from 2021 to 2025 and incorporate an annual 1.5% improvement factor, consistent with the OEB's October 3, 2025 letter. To support consistent reporting and comparison across the forecast period, Hydro One has also restated the 2026 and 2027 D-SAIDI targets using the same EB-2021-0307 methodology that leverages reliability performance data from 2021 to 2025.

These targets reflect the expected benefit from programs and investments such as Distribution Automation & Sectionalization Program (DSP Section 3.11, D-SS-05), Distribution Station Refurbishment program (DSP Section 3.11, D-SR-04), Pole Sustainment Program (DSP Section 3.11, D-SR-07), Selective Undergrounding (DSP Section 3.11, D-SR-14), Reliability Improvement Programs (DSP Section 3.11, D-SS-02), Energy Storage Solutions (DSP Section 3.11, D-SS-04), Distribution Lines Sustainment program (DSP Section 3.11, D-SR-10), Spare Transformer Purchases (DSP Section 3.11, D-SR-13), Power Quality and Stray Voltage Improvements (DSP Section 3.11, D-SS-06), and System Monitoring (DSP Section 3.11, D-SS-08) as well as improved storm response

and outage planning (Exhibit E-04-05, subsection 2.2.3) and planned maintenance programs including Defect Corrections (Exhibit E-03-02).

3.5.3.5.2 SAIDI FOR VEGETATION CAUSED INTERRUPTIONS

Performance Category	Measure	Description
System Reliability	SAIDI for 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 poor performance compared to the system wide metric. 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
SAIDI for Vegetation Caused Interruptions	2.7	2.5	1.7	2.0	2.1	▼	1.9	1.7	1.7

As described in Section 3.5.2.6, distributors were required to report on all 10 primary cause codes including ‘adverse weather’ cause code starting in March 2023. As a result, outages attributable to Tree Contact were classified as ‘Tree Contact’ regardless of weather conditions in 2021 and 2022, whereas from 2023 onward, these outages were reported separately under the ‘adverse weather’ category and therefore are excluded from the ‘SAIDI for Vegetation Caused Interruptions’ results presented for 2023 to 2025.

Hydro One's SAIDI for Vegetation-Caused Interruptions increased between 2024 and 2025 and exceeded target in each year. As described in Exhibit E-03-02, Hydro One faced increasing demand-driven work requests, compliance requirements, and inflationary pressures during this period. To manage these pressures within the approved funding envelope, Hydro One reprioritized work across programs and years, including deferring planned Vegetation Management and Lines Maintenance activities that could be

postponed without creating unacceptable system risk. While these decisions addressed near-term operational and compliance priorities, continued deferrals are not sustainable and impact Hydro One's SAIDI performance.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
SAIDI for Vegetation Caused Interruptions	2.0	2.0	2.0	1.9	1.9	1.8	1.8
SAIDI for Vegetation Caused Interruptions (EB-2021-0110)	1.7	1.7					

The 2028-2032 reliability targets were established using the target-setting methodology set out in OEB File No. EB-2021-0307. The targets are based on reliability performance data from 2021 to 2025 and incorporate an annual 1.5% improvement factor, consistent with the OEB's October 3, 2025 letter. To support consistent reporting and comparison across the forecast period, Hydro One has also restated the 2026 and 2027 D-SAIDI targets using the same EB-2021-0307 methodology that leverages reliability performance data from 2021 to 2025.

These targets reflect the expected benefit from planned maintenance programs including Vegetation Management as discussed in Exhibit E-03-02.

3.5.3.5.3 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
SAIDI - Rural - duration in hours	7.5	8.0	8.8	9.2	10.0	▲	5.2	4.8	4.7

Over the past 5 years, rural SAIDI performance has deteriorated due to increased tree contacts and equipment failure related interruptions. The performance trend reflects both increasing asset-related outage drivers associated with aging infrastructure and asset degradation and the challenges associated with maintaining reliability performance while responding to significant growth in demand-driven capital programs. In addition, vegetation-related reliability performance deteriorated beginning in 2023 as vegetation management execution declined due to unanticipated levels of overgrown vegetation and the reprioritization of resources to address emergent demand-driven work. Tree Contacts from 2023-2025 have steadily increased and are proportional with the increase in the duration of interruptions on the rural distribution system. Rural SAIDI performance was further impacted by a high number of storm days (38 in 2023, 48 in 2024, and 47 in 2025) compared to the 10-year historical average of 36 storm days per year. As mentioned in DSP 3.7, 3.7.2.4 “Shift in Climate”, Hydro One's distribution system now experiences approximately 40 storm days annually on average, representing a sustained increase relative to historical levels. The continued contribution of equipment failures and tree-related outages demonstrates the importance of sustained investments in asset renewal, vegetation management, and system maintenance activities to improve reliability performance over the long term.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
SAIDI - Rural - duration in hours	9.6	9.5	9.4	9.3	9.1	9.0	8.9
SAIDI - Rural - duration in hours (EB-2021-0110)	4.7	4.5					

The 2028-2032 reliability targets were established using the target-setting methodology set out in OEB File No. EB-2021-0307. The targets are based on reliability performance data from 2021 to 2025 and incorporate an annual 1.5% improvement factor, consistent with the OEB's October 3, 2025 letter. To support consistent reporting and comparison across the forecast period, Hydro One has also restated the 2026 and 2027 targets using the same EB-2021-0307 methodology that leverages reliability performance data from 2021 to 2025.

3.5.3.5.4 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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
SAIFI - Rural - frequency of outages	2.6	2.8	3.2	3.1	3.3	▲	2.3	2.1	2.0

Over the past 5 years, rural SAIFI has deteriorated, mainly due to increased tree contacts and equipment failure related interruptions. As described in DSP Section 3.1, and Exhibit E-03-02, Hydro One deferred certain planned OM&A and system renewal investments during the period as resources and capital were reprioritized to address growing customer demand for connection and development-related work and increased expenditures associated with storms. The performance trend over the period reflects both increasing asset-related outage drivers and the challenges associated with maintaining reliability performance while responding to significant growth in demand-driven capital programs. The SAIFI – Rural Frequency was also impacted by a high number of storm days (38 in 2023, 48 in 2024, and 47 in 2025) compared to the 10-year historical average of 36 storm days per year. As mentioned in DSP Section 3.7, 3.7.2.4 “Shift in Climate”, Hydro One's distribution system now experiences approximately 40 storm days annually on average, representing a sustained increase relative to historical levels. The continued contribution of equipment failures and tree-related outages demonstrates the importance of sustained investments in asset renewal, vegetation management, and system maintenance activities to improve reliability performance over the long term.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
SAIFI - Rural - frequency of outages	3.1	3.1	3.1	3.1	3.1	3.1	3.1
SAIFI - Rural - frequency of outages (EB-2021-0110)	2.0	1.9					

The 2028-2032 reliability targets were established using the target-setting methodology set out in OEB File No. EB-2021-0307. The targets are based on reliability performance data from 2021 to 2025 and incorporate an annual 0.25% improvement factor, consistent with the OEB's October 3, 2025 letter. To support consistent reporting and comparison across the forecast period, Hydro One has also restated the 2026 and 2027 targets using the same EB-2021-0307 methodology that leverages reliability performance data from 2021 to 2025.

3.5.3.5.5 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 2023-2025 TARGETS

								Hydro One Target	
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
SAIDI - Urban - duration in hours	2.8	2.8	3.5	3.1	2.9	▲	2.8	2.8	2.8

The performance trend reflects both increasing asset-related outage drivers associated with aging infrastructure and asset degradation and the challenges associated with maintaining reliability performance while responding to significant growth in demand-

driven capital programs. Urban SAIDI performance was further impacted by a high number of storm days (38 in 2023, 48 in 2024, and 47 in 2025) compared to the 10-year historical average of 36 storm days per year. As mentioned in DSP Section 3.7, 3.7.2.4 “Shift in Climate”, Hydro One's distribution system now experiences approximately 40 storm days annually on average, representing a sustained increase relative to historical levels.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
SAIDI - Urban - duration in hours	2.8	2.8	2.8	2.8	2.8	2.8	2.8
SAIDI - Urban - duration in hours (EB-2021-0110)	2.8	2.8					

The 2028-2032 reliability targets were established with the objective to keep SAIDI-Urban consistent with historical average.

3.5.3.5.6 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 2023-2025 TARGETS

								Hydro One Target	
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
SAIFI - Urban – frequency of outages	1.4	1.3	1.6	1.5	1.6	▲	1.5	1.5	1.5

Over the past 5 years, rural Urban SAIFI has slightly deteriorated, mainly due to increased equipment failure related interruptions. As described in DSP Section 3.1, and Exhibit E-03-02, Hydro One reprioritized certain planned OM&A and system renewal investments during the period to address demand-driven and cost pressure challenges as well as increased expenditures associated with storms. The performance trend over the period reflects both increasing asset-related outage drivers and the challenges associated with maintaining reliability performance while responding to significant growth in demand-

driven capital programs. The SAIFI – Urban Frequency was also impacted by a high number of storm days (38 in 2023, 48 in 2024, and 47 in 2025) compared to the 10-year historical average of 36 storm days per year. As mentioned in DSP Section 3.7, 3.7.2.4 "Shift in Climate", Hydro One's distribution system now experiences approximately 40 storm days annually on average, representing a sustained increase relative to historical levels. The continued contribution of equipment failures and tree-related outages demonstrates the importance of sustained investments in asset renewal, vegetation management, and system maintenance activities to improve reliability performance over the long term.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
SAIFI - Urban - frequency of outages	1.5	1.5	1.5	1.5	1.5	1.5	1.5
SAIFI - Urban - frequency of outages (EB-2021-0110)	1.5	1.5					

The 2028-2032 reliability targets were established with the objective to keep SAIFI-Urban consistent with historical average.

3.5.3.5.7 LARGE CUSTOMER INTERRUPTION FREQUENCY LARGE DISTRIBUTION ACCOUNTS

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 2023-2025 TARGETS

							Hydro One Targets		
Measure	**2021**	**2022**	**2023**	**2024**	**2025**	**Trend**	**2023**	**2024**	**2025**
Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	1.3	1.5	1.7	1.3	1.2	▼	1.6	1.6	1.6

Over the past five years, the interruption frequency per LDA has trended positively and has averaged 1.4 interruptions per year. In 2023, performance was 0.1 interruptions over the target of 1.6 mainly due to Loss of Supply events on the transmission system that affected these LDAs. This situation has improved later in 2024 and 2025. In 2021 and 2022, the performance was better than the target.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets						
Measure	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	1.6	1.6	1.6	1.6	1.6	1.6	1.6

The 2028-2032 targets were set up based on the objective to keep the Number of interruptions per LDA consistent with historical average.

3.5.3.5.8 FLEXIBILITY & LOCAL ENERGY EFFICIENCY (NEW METRIC)

Performance Category	Measure	Description
System Reliability	Flexibility & Local Energy Efficiency	Track the number of Hydro One customers that enroll in flexibility and local energy efficiency programs.

This metric tracks the number of Hydro One customers that enroll in flexibility and local energy efficiency programs. The measure provides an indication of customer participation in initiatives that support more efficient electricity use, demand reduction, and grid flexibility. Increased participation in these programs can create flexible capacity that may be leveraged to provide operational benefits and support future non-wires alternatives. The metric also reflects customer engagement in the adoption of distributed energy resources and other initiatives that support the broader energy transition. In addition, participation in these programs can provide customers with financial incentives and opportunities to reduce their electricity bills, while enhancing customer engagement and satisfaction.

TARGETS FOR THE 2028-2032 PERIOD

	Hydro One Targets				
Measure	**2028**	**2029**	**2030**	**2031**	**2032**
Flexibility & Local Energy Efficiency (# of Hydro One customers)	56,600	65,200	71,900	77,100	81,300

Flexibility & energy efficiency programs are a key enabler of Hydro One's Non-Wires Solutions (NWS) strategy. By growing participation in these programs, Hydro One develops a portfolio of dispatchable distributed energy resources (DERs) and energy efficiency initiatives that mitigate future load growth. Establishing DR and EE capabilities in advance provides a resource that can be quickly mobilized to address urgent or emerging capacity needs and support consideration of non-wires alternatives to traditional distribution investments. The proposed targets reflect Hydro One's objective of building over 80 MW of peak demand reduction capability, growing along with expected customer DER participation. This level of capability is expected to provide meaningful system value while remaining achievable based on Hydro One's experience with customer participation.

3.5.3.5.9 ENABLING REMOTE OPERABLE CAPABILITIES (NEW METRIC)

Performance Category	Measure	Description
System reliability	Enabling Remote Operable Capabilities	Tracks the percentage of sub-transmission feeders with remote operable capabilities, enabling reduced outage impacts and improved operational flexibility.

This metric is being introduced for the 2028-2032 period and will track the percentage of sub-transmission feeders equipped with remote operable capabilities. The measure is intended to capture Hydro One's progress in expanding remote operational capabilities across the distribution network. Increased remote operability enables faster fault isolation, remote power restoration, and load transfers through existing tie points, reducing outage duration and improving operational flexibility.

By measuring the extent of remote operational capability across the feeder network, the metric provides an indication of Hydro One's advancement toward a more modern and

resilient distribution system. The metric also supports Hydro One's grid modernization objectives by tracking investments that impact reliability, improve system responsiveness, and strengthen the utility's ability to manage system events and customer outages.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets				
Measure	**2028**	**2029**	**2030**	**2031**	**2032**
Enabling Remote Operable Capabilities	90% of M-class feeders by the end of 2032				

Hydro One currently has remote operable capabilities on 42% of sub-transmission feeders. The proposed 2028-2032 investments and target were established based on a review of the sub-transmission feeder population that indicated approximately 90% of those feeders would benefit from remote operable capabilities.

3.5.3.5.10 LOAD CAPACITY CONSTRAINED DISTRIBUTION STATIONS (NEW METRIC)

Performance Category	Measure	Description
System Reliability	Load Capacity Constrained Distribution Stations	Tracks the percentage of Hydro One Distribution Stations that are load capacity constrained, enabling additional capacity to support forecasted growth.

This metric will track the percentage of distribution stations that are constrained, when load is at or exceeding planning limits of the transformer. By measuring the extent of constrained distribution stations, the metric provides an indication of Hydro One’s progress towards addressing capacity limitations at the distribution station level. The metric also supports Hydro One's priorities of meeting Ontario’s growing demand through targeted investments to address constrained distribution stations.

TARGETS FOR THE 2026-2032 PERIOD

	Hydro One Targets				
Measure	**2028**	**2029**	**2030**	**2031**	**2032**
Load Capacity Constrained Distribution Stations	0-4% by the end of 2032				

Through the investments proposed for the 2028-2032 planning period, Hydro One plans to address all stations that are currently constrained, as well as those forecasted to become constrained during the period. These investments will create the additional capacity required to reliably serve existing customer demand and accommodate future load growth. The target of 0-4% capacity-constrained stations by the end of the 2032 rate period is reflective of the potential variability in the load forecast.

3.5.4 ADDRESSING THE ACTIVITY AND PERFORMANCE-BASED BENCHMARKING REPORT

On September 29, 2025, Pacific Economics Group Research LLC (PEG) published their 2025 report on the Activity and Program Based Benchmarking (APB).[10] In accordance with the OEB's Chapter 2 Filing Requirements, Hydro One has reviewed the APB results and has included the below discussion on performance for each of the ten programs.

Hydro One has included this evidence for completeness and to comply with the Board's filing requirements, while also providing appropriate context regarding the limitations of the APB metrics when applied to Hydro One's operating environment. In Hydro One's view, the APB metrics published by the Ontario Energy Board provide limited decision-useful insight for the assessment of Hydro One's performance or the development of its investment plans. While Hydro One recognizes that benchmarking can, in principle, be a useful analytical tool when applied with appropriate context and data integrity, the current APB framework does not adequately reflect Hydro One's operating realities, cost drivers, or service obligations.

Quantitative benchmarking outcomes must therefore be interpreted with caution and supplemented by qualitative, contextual analysis to avoid misleading conclusions. Hydro One has made every effort to provide this context in the discussion of results that follows. The APB metrics rely heavily on Uniform System of Accounts ("USoA") trial balance data that was not designed for activity-level cost comparison and that embeds fully allocated

[10] Pacific Economics Group Research LLC, Report to the Ontario Energy Board – Activity and Program-based Benchmarking – 2024 Unit Cost Report (EB 2018-0278)
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overheads, professional judgment, and entity-specific capitalization practices that vary materially across utilities. Further, Hydro One's scale, geographic footprint, customer dispersion, asset mix, and statutory obligations differ fundamentally from those of most Ontario distributors. These characteristics materially affect Hydro One's cost structure in ways that are not normalized in the APB metrics, limiting comparability and increasing the risk of false precision. Hydro One's investment planning and operational decisions are driven by assessments of asset condition, system risk, safety, and reliability outcomes, rather than by relative unit cost positioning.

Hydro One has provided in the evidence that follows year-over-year historical actuals for each of the ten programs identified in the OEB's Activities and Program Benchmarking Reports and has included an explanation of significant change (greater than 20% from previous year or five year average) and a plan to reduce unit costs if the five-year average is 25% greater than the industry five year average.

3.5.4.1 ACTIVITY AND PERFORMANCE-BASED BENCHMARKING UNIT COST RESULTS

3.5.4.1.1 BILLING O&M

Billing O&M is calculated by dividing the billing O&M costs incurred (USoA 5315) by the total number of customers. The 2020-2024 Billing O&M cost performance for Hydro One and the Industry Average is provided in Table 1. The variances relative to the prior year, the five-year average, and the industry five-year average do not exceed the threshold requiring a variance explanation.

Table 1 - Billing O&M - 2020-2024

	2020	2021	2022	2023	2024	5Y Avg
Costs	44,910	43,454	43,175	39,653	40,401	42,318
Total Customers	1,412	1,424	1,440	1,458	1,478	1,443
($/Customer)	31.80	30.51	29.97	27.20	27.34	29.36
YoY Change (%)		(4.1%)	(1.7%)	(9.3%)	0.5%	
Industry Average	27.35	27.04	28.02	27.60	25.82	27.17

3.5.4.1.2 METERS O&M

Meters O&M is calculated by dividing the meters O&M costs incurred (USoA 5065+5175+5310) by the total number of customers. The 2020-2024 Meters O&M cost performance for Hydro One and the Industry Average is provided in Table 2.

Table 2 - Meters O&M - 2020-2024

	2020	2021	2022	2023	2024	5Y Avg
Costs	27,307	27,329	30,506	28,659	28,998	28,560
Total Customers	1,412	1,424	1,440	1,458	1,478	1,443
($/Customer)	19.34	19.19	21.18	19.66	19.63	19.80
YoY Change (%)		(0.8%)	10.4%	(7.2%)	(0.2%)	
Industry Average	12.67	12.74	13.22	12.84	14.76	13.25

Hydro One's average 2020-2024 unit cost performance was 49% higher than the Industry Average of $13.25, largely due to the disproportionately high number of rural and remote customers in Hydro One's service territory, relative to most other Ontario distribution utilities. This metric does not adjust or normalize for the customer complexity of Hydro One's service territory, including seasonal customers, embedded networks, and service territory accessibility.

Hydro One's Meters O&M costs for 2024 are within -0.9% of the five year average. Annual expenditures for Hydro One's Distribution Sustainment Meters, Telecommunications and Control OM&A activities are described in Exhibit E-03-02, Section 2.3.

3.5.4.1.3 VEGETATION MANAGEMENT O&M

Vegetation Management O&M is calculated by dividing the vegetation management O&M costs incurred (USoA 5135) by the total number of poles. The 2020-2024 Vegetation Management O&M cost performance for Hydro One and the Industry Average is provided in Table 3. The variances relative to the prior year, the five-year average, and the industry five-year average do not exceed the threshold requiring a variance explanation.

Table 3 - Vegetation Management O&M - 2020-2024

	2020	2021	2022	2023	2024	5Y Avg
Costs ($M)	132,653	140,996	141,519	112,985	112,638	128,158
Total Poles (MM)	1,613	1,625	1,628	1,626	1,642	1,627
($/Pole)	82.24	86.76	86.90	69.47	68.59	78.79
YoY Change (%)		5.5%	0.2%	-20.1%	-1.3%	
Industry Average	65.46	68.64	70.86	60.99	60.21	65.23

3.5.4.1.4 LINES O&M

Lines O&M is calculated by dividing the lines O&M costs incurred (USoA 5020+5025+5040+5045+5090+5095+5125+5130+5145+5050+5155) by the total number of primary circuit kilometers. The 2020-2024 Lines O&M cost performance for Hydro One and the Industry Average is provided in Table 4. The variances relative to the prior year, the five-year average, and the industry five-year average do not exceed the threshold requiring a variance explanation.

Table 4 - Lines O&M - 2020-2024

	2020	2021	2022	2023	2024	5Y Avg
Costs ($M)	70,485	69,992	67,283	78,661	69,964	71,277
Total Primary Circuit KM of Line	124,310	124,556	124,741	124,948	125,229	124,757
($/km of Primary Line)	567.01	561.94	539.38	629.55	558.69	571.31
YoY Change (%)		-0.9%	-4.0%	16.7%	-11.3%	
Industry Average	1,044.10	1,051.66	1,165.72	1,201.08	1,131.96	1,118.90

3.5.4.1.5 DISTRIBUTION STATION EQUIPMENT O&M

Distribution Station Equipment O&M is calculated by dividing the distribution station equipment cost (USoA 5016+5017+5114) by the total MVA. The 2020-2024 Lines O&M cost performance for Hydro One and the Industry Average is provided in Table 5.

Table 5 - Distribution Station O&M - 2020-2024

	2020	2021	2022	2023	2024	5Y Avg
Costs ($M)	14,847	14,767	14,862	17,715	20,089	16,456
Total MVA	7,314	7,545	7,622	7,704	7,722	7,581
($/MVA)	2,029.97	1,957.18	1,949.83	2,299.47	2,601.50	2,167.59
YoY Change (%)		-3.6%	-0.4%	17.9%	13.1%	
Industry Average	1,265.73	1,531.51	1,399.59	1,457.62	1,611.48	1,453.19

Hydro One's average unit cost performance for 2020-2024 was 49% higher than the Industry Average of $1,453.19. The 2024 unit cost performance was 20% higher than Hydro One's five year average of $2,167.59. This metric does not adjust or normalize for variability in station complexity, security requirements, and communications infrastructure across distribution utilities. Hydro One's stations often service critical infrastructure and remote load pockets, requiring higher maintenance standards.

The higher station O&M expenditures observed in 2023 and 2024 were driven primarily by corrective maintenance requirements for aging station transformers and related station equipment. Corrective maintenance activities addressed deficiencies identified through condition monitoring programs, including transformer oil sampling, visual inspections, and diagnostic testing. As transformer corrective maintenance activities are typically bundled with switch and fuse maintenance to minimize outages and improve efficiency, increased transformer work volumes also resulted in higher expenditures for associated station assets. Annual expenditures for Hydro One's Distribution O&M activities are described in Exhibit E-03-02, Section 2.1.

3.5.4.1.6 POLES, TOWERS, AND FIXTURES O&M

Poles, Towers and Fixtures O&M is calculated by dividing the poles, towers, and fixtures O&M costs (USoA 5120) by the total number of poles. The 2020-2024 Lines O&M cost performance for Hydro One and the Industry Average is provided in Table 6. The variances

relative to the prior year, the five-year average, and the industry five-year average do not exceed the threshold requiring a variance explanation.

Table 6 - Poles, Towers, and Fixtures O&M - 2020-2024

	2020	2021	2022	2023	2024	5Y Avg
Costs ($M)	23,076	22,759	22,684	25,698	25,049	23,853
Total Poles	1,613	1,625	1,628	1,626	1,642	1,627
$/Pole	14.31	14.00	13.93	15.80	15.25	14.66
YoY Change (%)		-2.1%	-0.5%	13.4%	-3.5%	
Industry Average	12.52	12.44	13.18	12.95	13.25	12.87

3.5.4.1.7 CAPITAL EXPENDITURES: DISTRIBUTION STATION EQUIPMENT

Distribution Station Equipment Capital Expenditures is calculated by dividing the distribution station equipment capital expenditures (USoA 1820) by the total MVA. The 2020-2024 distribution station equipment cost performance for Hydro One and the Industry Average is provided in Table 7.

Table 7 - Distribution Station Equipment Capital Expenditures - 2020-2024

	2020	2021	2022	2023	2024	5Y Avg
Costs ($M)	42,000	41,408	40,255	30,408	31,512	37,117
Total MVA	7,314	7,545	7,622	7,704	7,722	7,581
$/MVA	5,742.44	5,488.08	5,281.44	3,947.03	4,080.82	4,907.96
YoY Change (%)		-4.4%	-3.8%	-25.3%	3.4%	
Industry Average	2,695.68	3,391.81	3,188.90	3,440.78	3,139.25	3,169.93

Hydro One's average unit cost performance from 2020-2024 was 55% higher than the Industry Average of $3,169.93. This metric, along with other capital APB metrics do not represent a consistent comparison across distribution utilities as capital expenditures are lumpy, project-driven, and timing-dependent with year-over-year unit costs distorted by major refurbishments and replacements.

Annual capital programs and planned capital expenditures for Distribution Station Equipment are primarily described within DSP Section 3.11, D-SR-04, D-SR-01, and D-SR-03.

3.5.4.1.8 CAPITAL EXPENDITURES: POLES, TOWERS AND FIXTURES

Poles, Towers and Fixtures Expenditures is calculated by dividing the total poles, towers, and fixtures capital expenditures (USoA 1830) by the total number of poles installed. The 2020-2024 Poles, Towers, and Fixtures capital expenditures cost performance for Hydro One and the Industry Average is provided in Table 8.

Table 8 - Poles, Towers and Fixtures Capital Expenditures - 2020-2024[11]

	2020	2021	2022	2023	2024	5Y Avg
Costs ($M)	-	-	504,882	502,248	633,418	546,849
Number of Pole Additions	-	-	18,375	17,493	18,630	18,166
$/Pole Added	-	-	27,476.55	28,711.34	33,999.87	30,062.59
YoY Change (%)				4.5%	18.4%	
Industry Average	10,445.51	10,889.53	20,232.90	20,923.12	25,737.96	19,461.81

Hydro One's average unit cost performance for 2020-2024 was 55% higher than the Industry Average of $19,461.81. This metric, along with other capital APB metrics do not represent a consistent comparison across distribution utilities as capital expenditures are lumpy, project-driven, and timing-dependent with year-over-year unit costs distorted by major refurbishments and replacements.

Annual capital programs and planned capital expenditures for Distribution Station Equipment are primarily described within DSP Section 3.11, D-SR-07 and D-SR-08.

[11] As stated in Hydro One's EB-2018-0278 January 19 2022 submission, prior to 2022 Hydro One did not internally report on the total number of poles or transformers installed as reporting was focused on the objectives of the originating program or project. As such, the 2020 and 2021 amounts are not included.

3.5.4.1.9 CAPITAL EXPENDITURES: LINE TRANSFORMERS

Line Transformers Capital Expenditures is calculated by dividing the Line Transformer capital expenditures (USoA 1850) by the number of line transformers. The 2020-2024 Line Transformer capital expenditures cost performance for Hydro One and the Industry Average is provided in Table 9. The variances relative to the prior year, the five-year average, and the industry five-year average do not exceed the threshold requiring a variance explanation.

Table 9 - Distribution Station Equipment Capital Expenditures - 2020-2024[12]

	2020	2021	2022	2023	2024	5Y Avg
Costs ($M)	-	11,809	10,163	12,334	12,865	11,793
Number of Line Tx Additions	-	-	12,347	12,520	15,402	13,423
$/Line Tx Added	-	-	823.15	985.11	835.28	881.18
YoY Change (%)				19.7%	-15.2%	
Industry Average	17,719.80	20,232.59	10,064.15	12,856.59	13,091.51	10,794.53

3.5.4.1.10 CAPITAL EXPENDITURES: METERS

Meters Capital Expenditures is calculated by dividing the Meters capital expenditures (USoA 1860) by the number of customers. The 2020-2024 Meters capital expenditures cost performance for Hydro One and the Industry Average is provided in Table 10.

[12] As stated in Hydro One's EB-2018-0278 January 19 2022 submission, prior to 2022 Hydro One did not internally report on the total number of poles or transformers installed as reporting was focused on the objectives of the originating program or project. As such, the 2020 and 2021 amounts are not included.

Table 10 - Meters Capital Expenditures - 2020-2024

	2020	2021	2022	2023	2024	5Y Avg
Costs ($M)	93,701	101,956	107,089	126,745	152,167	116,332
Number of Customers (MM)	1,412	1,424	1,440	1,458	1,478	1,443
$/Customer	66.35	71.58	74.35	86.93	102.98	80.44
YoY Change (%)		7.9%	3.9%	16.9%	18.5%	
Industry Average	28.56	28.43	29.43	35.65	41.55	32.78

Hydro One's average unit cost for 2020-2024 was 145% higher than the Industry Average of $32.78. The 2024 unit costs was 28% higher than the five year average of $80.44. This metric, along with other capital APB metrics do not represent a consistent comparison across distribution utilities as capital expenditures are lumpy, project-driven, and timing-dependent with year-over-year unit costs distorted by major refurbishments and replacements. In addition, this metric does not adjust or normalize for the customer complexity of Hydro One's service territory, including seasonal customers, embedded networks, and service territory accessibility.

Annual capital programs and planned capital expenditures for Meters are primarily described within DSP Section 3.11, D-SA-04 and D-SR-12.

Fiscal 2023 – Hydro One Networks Distribution OEB Scorecard, Management Discussion and Analysis ("Scorecard MD&A")

Hydro One Networks Distribution OEB Scorecard MD&A - General Overview

In Hydro One Networks Inc.'s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Agreement) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, Hydro One agreed as follows:

> *For each of Distribution and Transmission, Hydro One will prepare a scorecard. The scorecards will be prepared subject to the following conditions: i) they will be prepared annually, no earlier than September 30th each year to align with OEB RRR scorecards; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission rebasing application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.*[1]

The Hydro One 2023 Distribution Scorecard is attached and the discussion is set out below.

Customer Satisfaction

Hydro One collects customer satisfaction data through customer perception studies conducted by independent expert research firms.

- **Small Business and Residential Satisfaction**

  The Small Business and Residential ("SB&R") 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 SB&R customers' overall satisfaction with the service they receive from Hydro One. 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.

  The SB&R Satisfaction was 87% in 2023, which met the target of 87%.

[1] EB-2021-0110, Settlement Agreement, Appendix A

- **Handling of Unplanned Outages Satisfaction**

  This measure captures 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, after the outage has 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 Estimated Time of Restoration (ETR).

  The Handling of Unplanned Outages Satisfaction was 78% in 2023, which was slightly less than the target of 80%. This result was attributable to lower satisfaction with the accuracy of reconnection timing and the length of time it took to restore power.

- **Call Centre Customer Satisfaction**

  This measure captures 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 whether or not 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.

  The Call Centre Customer Satisfaction was 84% in 2023, which was slightly less than the target of 86%. This result was attributable to lower satisfaction in the areas of Outage, Account / Billing Inquiry and Field Services Calls.

- **myAccount Customer Satisfaction**

  This measure captures customer satisfaction with services delivered by Hydro One's myAccount web portal. The myAccount portal allows customers to view their bills, analyze their electricity usage and request several services online, in a convenient and efficient manner.

  The myAccount Customer Satisfaction was 68% in 2023, which was slightly better than the target of 66%.

Cost Control

- **Pole Replacement - Gross Cost per Unit**

  The Pole Replacement Gross Cost per Unit is defined as the total pole replacement costs, divided by the total number of poles replaced.

  The gross cost per pole was $15,216 in 2023, which exceeded the target of $10,608. This result is due to higher input costs including higher material costs, and a higher volume of more complex and labour-intensive poles being completed.

- **Vegetation Management – Gross Defect Correction Cost per km**

  The Vegetation Management Gross Defect Correction Cost per kilometer is measured as the total cost of the Optimal Cycle Protocol vegetation management program divided by the number of kilometers of line cleared.

  The Year-end Vegetation Management unit cost was $6,996 in 2023, which exceeded the target of $3,824. This result was attributable to greater amounts of vegetation management work required per kilometer than anticipated and increased labour costs.

- **Station Refurbishment – Gross Cost per MVA**

  The Station Refurbishment – Gross Cost per Mega Volt Amp ("MVA") is defined as the total cost of station refurbishments divided by the total number of refurbished MVAs. Every station refurbishment project has a unique scope of work resulting in variation of the total cost for each investment. The cost per MVA measure only considers projects which have a station MVA of less than 10 MVA.

  No station refurbishment projects were completed in 2023 because of equipment procurement issues, easement delays and reprioritization.

- **Operations, Maintenance and Administration (OM&A) dollars per customer**

  OM&A dollars per customer is defined as total OM&A divided by the number of customers.

  OM&A per customer was $459 in 2023, which exceeded the target of $416. This result reflects higher emergency restoration costs and a higher volume of customer-driven work, higher spending on information technology initiatives, and higher environmental

expenditures.

- **OM&A dollars per kilometer of line**

  OM&A dollars per kilometer of line is defined as total OM&A divided by the total number of kilometers of distribution lines.

  The OM&A per kilometer of line was $5,469 in 2023, which exceeded the target of $4,798. This result reflects higher emergency restoration costs and a higher volume of customer-driven work, higher spending on information technology initiatives, and higher environmental expenditures.

System Reliability

The System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) are tracked for a number of scenarios.

- **SAIDI for Equipment-Caused Interruptions**

  SAIDI for Equipment-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for equipment-caused interruptions. This metric tracks the SAIDI impact and outcome caused by distribution equipment failures on an annual basis.

  The SAIDI for Equipment Caused Interruptions was 2.0 hours in 2023, which exceeded the target of 1.7 hours. This result is due to increased storm days in 2023 (38 storm days compared to the 10-year historical average of 33 storm days per year).

- **SAIDI for Vegetation-Caused Interruptions**

  SAIDI for Vegetation-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for vegetation-caused interruptions. This 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.

The Vegetation Caused SAIDI was 1.7 hours in 2023, which was better than the target of 1.9 hours.

- **SAIDI – Rural Duration**

  SAIDI – Rural Duration is defined as the total number of hours of interruption for rural customers divided by the total number of rural customers served. All rural planned and unplanned interruptions of one minute or more (excluding Loss of Supply and Force Majeure Events) are used to calculate this measure.

  The SAIDI – Rural Duration was 8.8 hours in 2023, which exceeded the target of 5.2 hours. This is attributed to equipment and tree-caused interruptions arising in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 storm days per year.

- **SAIFI - Rural Frequency of Outages**

  SAIFI – Rural Frequency of Outages is defined as the total number of rural customer interruptions divided by the total number of rural customers served. The SAIFI-Rural metric tracks the average interruption frequency for the rural areas only. All rural planned and unplanned interruptions of one minute or more (excluding Loss of Supply and Force Majeure Events) are used to calculate this measure.

  The SAIFI - Rural Frequency of Outages had a frequency of 3.2 outages per rural customer in 2023, which exceeded the target of 2.3 outages per rural customer. This is attributed to equipment and tree-caused interruptions in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 storm days per year.

- **SAIDI – Urban Duration**

  SAIDI – Urban Duration of outages is defined as the total customer hours of interruption for urban customers divided by the total number of urban customers served.

  The SAIDI - Urban Duration was 3.5 hours in 2023, which exceeded the target of 2.8 hours. This is attributed to equipment and tree-caused interruptions in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 storm days per year.

- **SAIFI - Urban Frequency of Outages**

  SAIFI – Urban Frequency of Outages is defined as the total number of interruptions for urban customers divided by the total number of urban customers served. The SAIFI – Urban metric tracks the average interruption frequency for the urban areas only.

  The SAIFI - Urban Frequency of Outages had a frequency of 1.6 outages per urban customer in 2023, which exceeded the target of 1.5 outages per urban customer. This is attributed to equipment and tree-caused interruptions in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 storm days per year.

- **Large Customer Interruption Frequency**

  Large Customer Interruptions Frequency is defined as the total number of interruptions for Large Distribution Customer Accounts (“LDAs”) divided by the total number of large distribution accounts served. This metric tracks the sustained interruption frequency to all LDA customers connected to Hydro One.

  The Large Customer Interruption Frequency had a frequency of 1.7 interruptions per large distribution customer account in 2023, which exceeded the target of 1.6 interruptions per large distribution customer account. This is attributed to equipment and tree-caused interruptions in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 storm days per year.

Note to Readers of Fiscal 2023 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “can”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements and information. Such statements include, but are not limited to, references to the collection of customer satisfaction data, and the data’s scope and uses; expected timing of customer perception studies; the means by which customers interact with Hydro One; system reliability measures and expected outcomes of implementation; and targets. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include the scope, duration, and impacts of infectious diseases, including the COVID-19 pandemic and related developments including government and the company’s response and mitigation measures, legislative or regulatory developments, government policy and program developments, an unexpected increase in call centre volumes, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgment on the reporting date of the performance scorecard and could be markedly different in the future. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

Hydro One Networks Distribution OEB Scorecard

Year End Results

Performance Outcomes	Performance Categories	Measures	2018	2019	2020	2021	2022	Actual 2023	JRAP Target 2023
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction (%)	76%	86%	87%	89%	87%	87%	87%
		Handling of Unplanned Outages Satisfaction (%)	80%	78%	77%	78%	78%	78%	80%
		Call Centre Customer Satisfaction (%)	93%	90%	86%	86%	86%	84%	86%
		My Account Customer Satisfaction (%)	77%	72%	52%	60%	67%	68%	66%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in ($)	$9,799	$12,499	$10,624	$11,158	$13,133	$15,216	$10,608
		Vegetation Management - Gross Defect Correction (OCP) Cost per km ($)	$4,910	$5,609	$5,670	$4,019	$5,070	$6,996	$3,824
		Station Refurbishment - Gross Cost Per MVA ($)	$486,000	$512,000	$315,000	$356,899	$655,244	No projects in service	$425,000
		OM&A dollars per customer ($)	$415	$415	$410	$409	$461	$459	$416
		OM&A dollars per km of line ($)	$4,611	$4,644	$4,622	$4,779	$5,441	$5,469	$4,798
	System Reliability	SAIDI for Equipment Caused Interruptions (hrs)	2.1	2.5	2.3	2.1	2.6	2.0	1.7
		SAIDI for Vegetation Caused Interruptions (hrs)	2.8	2.4	3.1	2.7	2.5	1.7	1.9
		SAIDI - Rural - duration (hrs)	7.8	7.9	8.3	7.5	8.0	8.8	5.2
		SAIFI - Rural - frequency of outages	2.4	2.7	2.8	2.6	2.8	3.2	2.3
		SAIDI - Urban - duration (hrs)	2.6	3.2	2.7	2.8	2.8	3.5	2.8
		SAIFI - Urban - frequency of outages	1.3	1.5	1.3	1.4	1.3	1.6	1.5
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	2.1	1.5	1.6	1.3	1.5	1.7	1.6

Fiscal 2024 – Hydro One Networks Distribution OEB Scorecard, Management Discussion and Analysis ("Scorecard MD&A")

Hydro One Networks Distribution OEB Scorecard MD&A - General Overview

In Hydro One Networks Inc.'s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Agreement) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, Hydro One agreed as follows:

> *For each of Distribution and Transmission, Hydro One will prepare a scorecard. The scorecards will be prepared subject to the following conditions: i) they will be prepared annually, no earlier than September 30th each year to align with OEB RRR scorecards; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission rebasing application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.*[1]

The Hydro One 2024 Distribution Scorecard is attached and the discussion is set out below.

Customer Satisfaction

Hydro One collects customer satisfaction data through customer perception studies conducted by independent expert research firms.

- **Small Business and Residential Satisfaction**

  The Small Business and Residential ("SB&R") 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 SB&R customers' overall satisfaction with the service they receive from Hydro One. 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.

  The SB&R Satisfaction was 88% in 2024, which was better than the target of 87%.

[1] EB-2021-0110, Settlement Agreement, Appendix A

- **Handling of Unplanned Outages Satisfaction**

  This measure captures 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, after the outage has 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 Estimated Time of Restoration (ETR).

  The Handling of Unplanned Outages Satisfaction was 79% in 2024, which was less than the target of 81%. This result was attributable to lower overall satisfaction with Hydro One's communication during outages.

- **Call Centre Customer Satisfaction**

  This measure captures 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 whether or not 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.

  The Call Centre Customer Satisfaction was 86% in 2024, which met the target of 86%.

- **myAccount Customer Satisfaction**

  This measure captures customer satisfaction with services delivered by Hydro One's myAccount web portal. The myAccount portal allows customers to view their bills, analyze their electricity usage and request several services online, in a convenient and efficient manner.

  The myAccount Customer Satisfaction was 72% in 2024, which was better than the target of 67%.

Cost Control

- **Pole Replacement - Gross Cost per Unit**

  The Pole Replacement Gross Cost per Unit is defined as the total pole replacement costs, divided by the total number of poles replaced.

  The gross cost per pole replacement was $19,477 in 2024, which was higher than the target of $10,818. This result is due to carry-over costs from the previous year, higher material and contractor costs, and a higher volume of more complex and labour-intensive poles being completed.

- **Vegetation Management – Gross Defect Correction Cost per km**

  The Vegetation Management Gross Defect Correction Cost per kilometer is measured as the total cost of the Optimal Cycle Protocol vegetation management program divided by the number of kilometers of line cleared.

  The Vegetation Management unit cost was $8,026 in 2024, which was higher than the target of $3,901. This result is due to increased defect densities and higher labour costs.

- **Station Refurbishment – Gross Cost per MVA**

  The Station Refurbishment – Gross Cost per Mega Volt Amp (“MVA”) is defined as the total cost of station refurbishments divided by the total number of refurbished MVAs. Every station refurbishment project has a unique scope of work resulting in variation of the total cost for each investment. The cost per MVA measure only considers projects which have a station MVA of less than 10 MVA.

  The Station Refurbishment cost was $818,524 per MVA in 2024, which was higher than the target of $423,000 per MVA. This result was attributable to increased material costs.

- **Operations, Maintenance and Administration (OM&A) dollars per customer**

  OM&A dollars per customer is defined as total OM&A divided by the number of customers.

  The OM&A per customer was $474 in 2024, which was higher than the target of $418. This reflects higher emergency restoration costs

and demand driven work, and higher spending on information technology initiatives.

- **OM&A dollars per kilometer of line**

  OM&A dollars per kilometer of line is defined as total OM&A divided by the total number of kilometers of distribution lines.

  The OM&A per kilometer of line was $5,709 in 2024, which was higher than the target of $4,838. This reflects higher emergency restoration costs and demand driven work, and higher spending on information technology initiatives.

System Reliability

The System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) are tracked for a number of scenarios.

- **SAIDI for Equipment-Caused Interruptions**

  SAIDI for Equipment-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for equipment-caused interruptions. This metric tracks the SAIDI impact and outcome caused by distribution equipment failures on an annual basis.

  The SAIDI for Equipment Caused Interruptions was 1.7 hours in 2024, which was slightly higher than the target of 1.6 hours.

- **SAIDI for Vegetation-Caused Interruptions**

  SAIDI for Vegetation-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for vegetation-caused interruptions. This 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 benefits 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.

  The Vegetation Caused SAIDI was 2.0 hours in 2024, which was higher than the target of 1.7 hours. This result is due to increased

storm days in 2024, including 48 storm days compared to the 10-year historical average of 34 storm days per year.

- **SAIDI – Rural Duration**

  SAIDI – Rural Duration is defined as the total number of hours of interruption for rural customers divided by the total number of rural customers served. All rural planned and unplanned interruptions of one minute or more (excluding Loss of Supply and Force Majeure Events) are used to calculate this measure.

  The SAIDI – Rural Duration was 9.2 hours in 2024, which was higher than the target of 4.8 hours. This result is due to increased storm days in 2024, including 48 storm days compared to the 10-year historical average of 34 storm days per year.

- **SAIFI - Rural Frequency of Outages**

  SAIFI – Rural Frequency of Outages is defined as the total number of rural customer interruptions divided by the total number of rural customers served. The SAIFI-Rural metric tracks the average interruption frequency for the rural areas only. All rural planned and unplanned interruptions of one minute or more (excluding Loss of Supply and Force Majeure Events) are used to calculate this measure.

  The SAIFI - Rural Frequency of Outages had a frequency of 3.1 outages per rural customer in 2024, which was higher than the target of 2.1 outages per rural customer. This result is due to increased storm days in 2024, including 48 storm days compared to the 10-year historical average of 34 storm days per year.

- **SAIDI – Urban Duration**

  SAIDI – Urban Duration of outages is defined as the total customer hours of interruption for urban customers divided by the total number of urban customers served.

  The SAIDI - Urban Duration was 3.1 hours in 2024, which was higher than the target of 2.8 hours. This result is due to increased storm days in 2024, including 48 storm days compared to the 10-year historical average of 34 storm days per year.

- **SAIFI - Urban Frequency of Outages**

SAIFI – Urban Frequency of Outages is defined as the total number of interruptions for urban customers divided by the total number of urban customers served. The SAIFI – Urban metric tracks the average interruption frequency for the urban areas only.

The SAIFI - Urban Frequency of Outages had a frequency of 1.5 outages per urban customer in 2024, which met the target of 1.5.

- **Large Customer Interruption Frequency**

  Large Customer Interruptions Frequency is defined as the total number of interruptions for Large Distribution Customer Accounts ("LDAs") divided by the total number of large distribution accounts served. This metric tracks the sustained interruption frequency to all LDA customers connected to Hydro One.

  The Large Customer Interruption Frequency had a frequency of 1.3 interruptions per large distribution customer account in 2024, which was better than the target of 1.6 interruptions per large distribution customer account.

Note to Readers of Fiscal 2024 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “can”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements and information. Such statements include, but are not limited to, references to the collection of customer satisfaction data, and the data’s scope and uses; expected timing of customer perception studies; the means by which customers interact with Hydro One; system reliability measures and expected outcomes of implementation; and targets. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include the scope, duration, and impacts of infectious diseases, including the COVID-19 pandemic and related developments including government and the company’s response and mitigation measures, legislative or regulatory developments, government policy and program developments, an unexpected increase in call centre volumes, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgment on the reporting date of the performance scorecard and could be markedly different in the future. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

Hydro One Networks Distribution OEB Scorecard

Year End Results

Performance Outcomes	Performance Categories	Measures	2019	2020	2021	2022	2023	Actual 2024	JRAP Target 2024
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction (%)	86%	87%	89%	87%	87%	88%	87%
		Handling of Unplanned Outages Satisfaction (%)	78%	77%	78%	78%	78%	79%	81%
		Call Centre Customer Satisfaction (%)	90%	86%	86%	86%	84%	86%	86%
		My Account Customer Satisfaction (%)	72%	52%	60%	67%	68%	72%	67%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in ($)	$12,499	$10,624	$11,158	$13,133	$15,216	$19,477	$10,818
		Vegetation Management - Gross Defect Correction (OCP) Cost per km ($)	$5,609	$5,670	$4,019	$5,070	$6,996	$8,026	$3,901
		Station Refurbishment - Gross Cost Per MVA ($)	$512,000	$315,000	$356,899	$655,244	No projects in service	$818,524	$423,000
		OM&A dollars per customer ($)	$415	$410	$409	$461	$459	$474	$418
		OM&A dollars per km of line ($)	$4,644	$4,622	$4,779	$5,441	$5,469	$5,709	$4,838
	System Reliability	SAIDI for Equipment Caused Interruptions (hrs)	2.5	2.3	2.1	2.6	2.0	1.7	1.6
		SAIDI for Vegetation Caused Interruptions (hrs)	2.4	3.1	2.7	2.5	1.7	2.0	1.7
		SAIDI - Rural - duration (hrs)	7.9	8.3	7.5	8.0	8.8	9.2	4.8
		SAIFI - Rural - frequency of outages	2.7	2.8	2.6	2.8	3.2	3.1	2.1
		SAIDI - Urban - duration (hrs)	3.2	2.7	2.8	2.8	3.5	3.1	2.8
		SAIFI - Urban - frequency of outages	1.5	1.3	1.4	1.3	1.6	1.5	1.5
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	1.5	1.6	1.3	1.5	1.7	1.3	1.6

Fiscal 2025 – Hydro One Networks Distribution OEB Scorecard, Management Discussion and Analysis ("Scorecard MD&A")

Hydro One Networks Distribution OEB Scorecard MD&A - General Overview

In Hydro One Networks Inc.'s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Agreement) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, Hydro One agreed as follows:

> *For each of Distribution and Transmission, Hydro One will prepare a scorecard. The scorecards will be prepared subject to the following conditions: i) they will be prepared annually, no earlier than September 30th each year to align with OEB RRR scorecards; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission rebasing application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.*[1]

The Hydro One 2025 Distribution Scorecard discussion is set out below.

Customer Satisfaction

Hydro One collects customer satisfaction data through customer perception studies conducted by independent expert research firms.

- **Small Business and Residential Satisfaction**

  The Small Business and Residential ("SB&R") 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 SB&R customers' overall satisfaction with the service they receive from Hydro One. 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.

  The SB&R Satisfaction was 88% in 2025, which met the target of 87%.

[1] EB-2021-0110, Settlement Agreement, Appendix A

- **Handling of Unplanned Outages Satisfaction**

  This measure captures 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, after the outage has 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 Estimated Time of Restoration (ETR).

  The Handling of Unplanned Outages Satisfaction was 80% in 2025, which did not meet the target of 82%. This is primarily attributable to satisfaction with the amount of time it took to restore power and satisfaction with ETR accuracy.

- **Call Centre Customer Satisfaction**

  This measure captures 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 a customer inquiry has been addressed appropriately. This metric demonstrates whether services are 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.

  The Call Centre Customer Satisfaction was 84% in 2025, which did not meet the target of 86%. This was primarily attributable to outage communications, account and billing calls, and a higher share of complex inquiries that required more effort to resolve as digital and self-service channels shifted routine transactions away from the call centre.

- **myAccount Customer Satisfaction**

  This measure captures customer satisfaction with services delivered by Hydro One's myAccount web portal. The myAccount portal allows customers to view their bills, analyze their electricity usage and request several services online, in a convenient and efficient manner.

  The myAccount Customer Satisfaction was 66% in 2025, which did not meet the target of 68%. This was primarily attributable to two isolated technical issues experienced where corrective actions have been implemented.

Cost Control

- **Pole Replacement - Gross Cost per Unit**

  The Pole Replacement Gross Cost per Unit is defined as the total pole replacement costs, divided by the total number of poles replaced.

  The gross cost per pole replacement was $18,191 in 2025, which did not meet the target. This result reflects increased unit costs driven by the ramp-down and deferral of portions of the replacement program to higher-priority safety and reliability work. Lower replacement volumes, while design, permitting, and other preparatory activities continued, resulted in fixed and trailing costs being spread across fewer completed units. The use of contractors also contributed to higher labour expenses.

- **Vegetation Management – Gross Defect Correction Cost per km**

  The Vegetation Management Gross Defect Correction Cost per kilometer is measured as the total cost of the Optimal Cycle Protocol vegetation management program divided by the number of kilometers of line cleared.

  The Vegetation Management unit cost was $8,580 in 2025, which did not meet the target. This result is due primarily to increased defect densities and more complex vegetation conditions than anticipated. Reduced brush management in prior years resulted in greater vegetation growth requiring increased effort per kilometer. In addition, a greater proportion of work required specialized resources to safely manage vegetation within proximity limits, resulting in higher labour expenses.

- **Station Refurbishment – Gross Cost per MVA**

  The Station Refurbishment – Gross Cost per Mega Volt Amp (“MVA”) is defined as the total cost of station refurbishments divided by the total number of refurbished MVAs. Every station refurbishment project has a unique scope of work resulting in variation of the total cost for each investment. The cost per MVA measure only considers projects which have a station MVA of less than 10 MVA.

  The Station Refurbishment cost was $917,979 per MVA in 2025, which did not meet the target. This result is due to the lower number of completed projects, dependence on higher-cost solutions due to the unavailability of lower-cost padmount distribution stations, and increased material and labour expenses.

- **Operations, Maintenance and Administration (OM&A) dollars per customer**

  OM&A dollars per customer is defined as total OM&A divided by the number of customers.

  The OM&A per customer was $419 in 2025, which met the target of $469.

- **Operations, Maintenance and Administration (OM&A) dollars per kilometer of line**

  OM&A dollars per kilometer of line is defined as total OM&A divided by the total number of kilometers of distribution lines.

  The OM&A per kilometer of line was $5,058 per km in 2025, which met the target of $5,393.

System Reliability

The System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) are tracked for a number of scenarios.

- **SAIDI for Equipment-Caused Interruptions**

  SAIDI for Equipment-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for equipment-caused interruptions. This metric tracks the SAIDI impact and outcome caused by distribution equipment failures on an annual basis.

  The SAIDI for Equipment Caused Interruptions was 1.9 hours in 2025, which did not meet the target of 1.5 hours. This was primarily attributed to a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **SAIDI for Vegetation-Caused Interruptions**

  SAIDI for Vegetation-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for vegetation-caused interruptions. This 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 benefits 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.

The Vegetation Caused SAIDI was 2.1 hours in 2025, which did not meet the target of 1.7 hours. This was primarily attributed to a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year and an increased tree/defect density.

- **SAIDI – Rural Duration**

  SAIDI – Rural Duration is defined as the total number of hours of interruption for rural customers divided by the total number of rural customers served. All rural planned and unplanned interruptions of one minute or more (excluding loss of supply and force majeure events) are used to calculate this measure.

  The SAIDI – Rural Duration was 10.0 hours in 2025, which did not meet the target. This was primarily attributed to tree contacts and equipment failures, coupled with a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **SAIFI - Rural Frequency of Outages**

  SAIFI – Rural Frequency of Outages is defined as the total number of rural customer interruptions divided by the total number of rural customers served. The SAIFI – Rural metric tracks the average interruption frequency for the rural areas only. All rural planned and unplanned interruptions of one minute or more (excluding loss of supply and force majeure events) are used to calculate this measure.

  The SAIFI - Rural Frequency of Outages had a frequency of 3.3 outages per rural customer in 2025, which did not meet the target. This was primarily attributed to tree contacts and equipment failures, coupled with a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **SAIDI – Urban Duration**

  SAIDI – Urban Duration of outages is defined as the total customer hours of interruption for urban customers divided by the total number

of urban customers served.

The SAIDI - Urban Duration was 2.9 hours in 2025, which did not meet the target of 2.8 hours. This was primarily attributed to equipment failures and a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **SAIFI - Urban Frequency of Outages**

  SAIFI – Urban Frequency of Outages is defined as the total number of interruptions for urban customers divided by the total number of urban customers served. The SAIFI – Urban metric tracks the average interruption frequency for the urban areas only.

  The SAIFI - Urban Frequency of Outages had a frequency of 1.6 outages per urban customer in 2025, which did not meet the target of 1.5. This was primarily attributed to equipment failures and a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **Large Customer Interruption Frequency**

  Large Customer Interruptions Frequency is defined as the total number of interruptions for Large Distribution Customer Accounts (“LDAs”) divided by the total number of large distribution accounts served. This metric tracks the sustained interruption frequency to all LDA customers connected to Hydro One.

  The Large Customer Interruption Frequency had a frequency of 1.2 interruptions per large distribution customer account in 2025, which met the target of 1.6 interruptions per large distribution customer account.

Note to Readers of Fiscal 2025 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “can”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements and information. Such statements include, but are not limited to, references to expected outcomes and customer benefits of the vegetation management program, and targets. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include legislative or regulatory developments, government policy and program developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgment on the reporting date of the performance scorecard and could be markedly different in the future. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

Hydro One Networks Distribution OEB Scorecard

Performance Outcomes	Performance Categories	Measures	2020	2021	2022	2023	2024	2025	JRAP Target 2025
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction (%)	87%	89%	87%	87%	88%	88%	87%
		Handling of Unplanned Outages Satisfaction (%)	77%	78%	78%	78%	79%	80%	82%
		Call Centre Customer Satisfaction (%)	86%	86%	86%	84%	86%	84%	86%
		My Account Customer Satisfaction (%)	52%	60%	67%	68%	72%	66%	68%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in ($)	$10,624	$11,158	$13,133	$15,216	$19,477	$18,191	$11,032
		Vegetation Management - Gross Defect Correction (OCP) Cost per km ($)	$5,670	$4,019	$5,070	$6,996	$8,026	$8,580	$3,980
		Station Refurbishment - Gross Cost Per MVA ($)	$315,000	$356,899	$655,244	No projects in service	$818,524	$917,979	$421,000
		OM&A dollars per customer ($)	$410	$409	$461	$459	$474	$419	$469
		OM&A dollars per km of line ($)	$4,622	$4,779	$5,441	$5,469	$5,709	$5,058	$5,393
	System Reliability	SAIDI for Equipment Caused Interruptions (hrs)	2.3	2.1	2.6	2.0	1.7	1.9	1.5
		SAIDI for Vegetation Caused Interruptions (hrs)	3.1	2.7	2.5	1.7	2.0	2.1	1.7
		SAIDI - Rural - duration (hrs)	8.3	7.5	8.0	8.8	9.2	10.0	4.7
		SAIFI - Rural - frequency of outages	2.8	2.6	2.8	3.2	3.1	3.3	2.0
		SAIDI - Urban - duration (hrs)	2.7	2.8	2.8	3.5	3.1	2.9	2.8
		SAIFI - Urban - frequency of outages	1.3	1.4	1.3	1.6	1.5	1.6	1.5
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	1.6	1.3	1.5	1.7	1.3	1.2	1.6

SECTION 3.6 – DSP – OTHER CAPITAL PLANNING FACTORS AND CONSIDERATIONS

3.6.1 INTRODUCTION

Sections 3.2 through 3.5 of the Distribution System Plan (DSP) outline key planning considerations related to distribution system needs, asset condition, benchmarking, productivity and continuous improvement, and performance measurement factors.

This Section describes the additional capital planning factors and analyses that Hydro One considered in developing the DSP and shaping the proposed plan.

These considerations address changes in future electricity demand, emerging system requirements and opportunities to optimize the timing, configuration and type of investments included in the Plan. They complement Hydro One's established asset condition, reliability, customer need and system planning inputs and are incorporated into investment decisions where applicable.

In particular, this Section describes how Hydro One:

- considers uncertainty in future electricity demand through multiple demand forecast scenarios and asset-level capacity planning (Section 3.6.2);
- evaluates longer-term electrification outcomes through the 2030-2050 Electrification Scenario Study (Section 3.6.3) and incorporates expected electrification impacts into near-term load forecasting, capacity planning, customer connections and secondary-system planning (Section 3.6.4);
- incorporates Non-Wires Solutions (NWS) into its investment planning process to determine whether qualifying system needs can be cost-effectively deferred or addressed through non-wires solutions rather than conventional infrastructure (Section 3.6.5);
- applies the OEB's Vulnerability Assessment and System Hardening (VASH) framework to assess climate vulnerability, pre-assess potential resilience measures and evaluate their customer value through benefit-cost analysis (Section 3.6.6); and

- considers opportunities to reduce distribution system losses through system planning, design standards and investments undertaken to address broader system needs (Section 3.6.7).

3.6.2 DEMAND FORECAST AND CAPACITY PLANNING

Hydro One plans its distribution system to provide sufficient capacity to reliably serve existing customers and accommodate reasonable forecast load growth, consistent with the requirements of the Distribution System Code ("DSC"). Capacity constraints arise when forecast demand exceeds the planning limits of individual system components, including distribution station transformers, feeders and downstream equipment. Growth on Hydro One's distribution system can also result in the need for additional upstream transformer station or transmission system capacity.

Hydro One identifies these requirements through its load forecasting and system planning processes. These processes evaluate existing system loading and forecast demand against the planning limits and operating requirements of individual assets to determine where additional capacity is required and the timing by which it is needed.

Future demand is inherently forward-looking. The timing, location and magnitude of future electricity demand are affected by factors including population and housing growth, economic development, customer connection activity, electrification and weather. System- and regional-level demand forecasts establish the broader demand outlook and the range of uncertainty around that outlook. Individual capacity needs are then identified through localized forecasts and assessments of the specific feeders, stations and upstream supply facilities affected.

Consistent with the OEB's filing requirements, Hydro One has developed reference, low and high demand scenarios and considered the implications of this range of future demand in its distribution capacity planning.

3.6.2.1 2028-2032 MULTIPLE DEMAND FORECAST SCENARIOS

Hydro One has developed a reference demand forecast together with low and high demand scenarios to reflect uncertainty in the principal factors expected to influence future electricity demand. The reference forecast is consistent with the load forecast provided in Exhibit D-05-01 and is informed by the economic and demographic assumptions described in Exhibit D-03-01. The reference forecast is net of forecast Conservation and Demand Management impacts.

The high and low scenarios vary both the underlying economic outlook and the assumed pace of electrification relative to the reference forecast. Under the high scenario, GDP growth and housing starts are assumed to develop more quickly than under the reference forecast, and the adoption of electric vehicles, electric space and water heating, public transit electrification and industrial electrification is assumed to occur at a faster rate. The low scenario applies the converse assumptions. Hydro One also separately considers weather variation around these economic and electrification scenarios.

Table 1 summarizes the resulting Hydro One Distribution peak-demand scenarios.

Table 1 - Hydro One Distribution Peak Demand Forecast Scenarios (MW)

Scenario	2026	2027	2028	2029	2030	2031	2032
Low	6,881	6,859	6,850	6,935	7,013	7,083	7,152
Reference	6,903	6,912	6,942	7,072	7,199	7,326	7,453
High	6,925	6,965	7,034	7,210	7,389	7,575	7,763

Hydro One's reference distribution peak is forecast to increase from 6,903 MW in 2026 to 7,453 MW in 2032. The low and high scenarios provide a range around this expected demand outlook reflecting uncertainty in economic growth, electrification and weather. These scenarios inform the assessment of planning uncertainty.

Regional Reference Demand Outlook

Hydro One serves customers across regions with materially different economic, demographic, customer and development characteristics, and unused capacity in one region

cannot generally address a localized capacity constraint in another. Hydro One therefore also developed the demand scenarios at a regional level. Table 2 summarizes the reference peak-demand outlook by region.

Table 2 - Regional Reference Peak Demand Outlook[1]

Region	2026 Reference Peak (MW)	2032 Reference Peak (MW)	Increase (MW)	Increase
South	2,525	2,817	292	11.6%
Central	2,005	2,142	137	6.8%
East	1,707	1,799	92	5.4%
North	666	696	30	4.5%

Forecast demand growth is most pronounced in South and Central Ontario, which together account for much of the forecast increase in Hydro One Distribution peak demand through 2032. This is consistent with the distribution of the material load-growth investments identified through Hydro One's system planning process. DSP Section 3.11, D-SS-01 identifies 190 material investments for the 2028–2032 period; approximately 43% and 30% of these investments address system constraints in the South and Central Ontario regions, respectively. Accordingly, the geographic distribution of Hydro One's proposed capacity investments is aligned with the areas where the greatest load growth and associated system capacity pressures are forecast.

3.6.2.2 ASSET-LEVEL CAPACITY ASSESSMENTS

While system and regional forecasts provide the overall demand outlook, the need for individual distribution investments is established through asset-level capacity assessments based on localized load growth.

As described in DSP Section 3.11, D-SS-01, Hydro One applies a systematic planning process informed by historical feeder and station level loading and forecast demand. Localized capacity assessments are based on information received from customers,

[1] Figures presented in the tables may not sum to the totals shown due to rounding.

developers, and municipalities, to inform the identification of local system constraints. Forward-looking demand expectations also reflect applicable economic and demographic assumptions.

These forecasts are applied at the asset level to determine when individual system components are expected to approach or exceed their planning limits. This asset-level assessment is particularly important for Hydro One because capacity requirements are driven by the location and characteristics of load growth. System-wide demand growth does not translate uniformly across Hydro One's service territory. Individual areas may experience material residential development, commercial or industrial expansion, or other customer growth that causes specific stations or feeders to reach their planning limits earlier than indicated by aggregate system growth.

The resulting capacity needs form the basis for the investments described in DSP Section 3.11, D-SS-01.

3.6.2.3 CAPACITY NEEDS INFORMING THE 2028-2032 INVESTMENT PLAN

Hydro One's planning assessments identify capacity needs at both the distribution level and within the upstream transmission system that supplies distribution customers.

Distribution System Capacity

Where forecast demand approaches or exceeds the capability of existing distribution facilities, Hydro One evaluates the appropriate means of providing additional capacity. Depending on the nature of the constraint, this can require feeder expansion or reconfiguration, additional transformation capacity, new or expanded distribution stations, voltage conversion or other system modifications.

Hydro One addresses localized growth requirements through DSP Section 3.11, D-SS-01 System Upgrades Driven by Load Growth. These load growth investments target station transformers and feeders that are already operating beyond their applicable planning limits, as well as assets that are forecast to reach or exceed their planning limits during the 2028-

2032 period based on the asset-level demand forecasts described above. As set out in DSP Section 3.11, D-SS-01, a significant portion of the capacity needs identified in this program have already materialized, underscoring the necessity for incremental investments in the upcoming period to address both existing constraints and plan for reasonable load growth in accordance with Hydro One's obligations under the DSC.

Upstream Transmission Supply Capacity

Some distribution load-growth needs also require expansion of the upstream transmission system that supplies Hydro One's distribution customers.

These requirements are identified through Hydro One's planning activities and, for broader regional supply requirements, through the Regional Planning process involving Hydro One Distribution, Hydro One Transmission, the IESO and other affected distributors. Regional Planning evaluates forecast regional needs over a longer planning horizon and identifies the transmission and distribution infrastructure required to reliably serve those needs.

Where additional Hydro One Transmission facilities are required to accommodate distribution load growth, Hydro One Distribution may be required to make a capital contribution toward the associated transmission investment pursuant to the Transmission System Code. These investments are described in GSP Section 4.11, G-GP-22, Distribution Capital Contribution to Hydro One Transmission.

GSP Section 4.11, G-GP-22 includes investments associated with transmission line upgrades and extensions, new transformer stations, upgrades to existing transformer stations and additional feeder positions. The underlying needs span multiple regional planning areas and reflect the upstream infrastructure necessary to make additional capacity available to Hydro One's distribution system. SPF Section 1.2, Attachment 52 is a letter from Hydro One Transmission's Regional Planning Group to Hydro One Distribution which summarizes Hydro One Distribution's participation in IESO led regional planning activities.

3.6.2.4 CONSIDERATION OF MULTIPLE DEMAND SCENARIOS

The 2028-2032 capacity projects proposed in DSP Section 3.11, D-SS-01 and GSP Section 4.11, G-GP-22 were developed using the reference planning outlook and the asset-level forecasts applicable to individual system needs. Hydro One also considered the range represented by the low and high demand scenarios to assess how forecast uncertainty could affect its capacity planning decisions. The scenarios provide a means of assessing whether the needs identified under the reference outlook are reasonably robust to changes in demand.

The 2028-2032 capacity plan represents a prudent response to the identified system needs and forecast uncertainty. The plan is supported by the following principal considerations.

First, the load growth investments are supported by asset-level assessments that evaluate historical loading and forecast demand against Hydro One's planning limits, equipment ratings and applicable system requirements.

Second, a significant portion of the identified capacity constraints has already materialized, and the remaining targeted assets are forecast to reach their planning limits during the 2028–2032 period. DSP Section 3.11, D-SS-01 demonstrates that these assets are materially more capacity constrained than the broader station and feeder populations.

Third, the overall investment requirement remains robust under a lower demand outcome. Reasonable variation in the timing and magnitude of future growth does not significantly alter the underlying need for the proposed capital plan.

Hydro One also recognizes that the timing and magnitude of future load growth may differ from forecast. Consistent with DSP Section 3.11, D-SS-01, Hydro One considers the expected timing of forecast load when prioritizing and pacing investments, with more immediate system needs prioritized for earlier execution and investments associated with later needs staged to align with expected demand growth. Hydro One also monitors system

loading and customer developments and updates local forecasts as required to support investment decisions.

This approach provides a reasonable balance between avoiding premature capacity investment and ensuring that sufficient infrastructure can be placed in service before forecast constraints impair reliable system operation or Hydro One's ability to accommodate customer load growth.

3.6.3 ELECTRIFICATION SCENARIO ANALYSIS FOR 2030-2050

Consistent with the terms of the OEB-approved settlement agreement in EB-2021-0110, Hydro One engaged ERM International Group Limited (ERM), to examine general electrification scenarios over the 2030-2050 timeframe. ERM presented their preliminary findings to intervenors from the prior application in a session on November 25, 2025.

The ERM Electrification Scenario Study 2030-2050 ("ERM Study"), filed as Attachment 6 to DSP Section 3.3, evaluates a range of electrification scenarios and their potential impacts on Hydro One Distribution's supply stations. The ERM Study also assesses the extent to which demand-side solutions, including energy efficiency, distributed energy resources ("DERs"), and demand-side flexibility, may mitigate electrification-driven peak demand growth. Where cost-effective and consistent with regulatory requirements, these solutions may defer or reduce the need for localized traditional infrastructure investments to meet growing demand.

The ERM Study is a long-term scenario analysis that serves a fundamentally different purpose from Hydro One’s near-term distribution revenue and load forecasts (Exhibits D-03-02 and D-05-01) and the Multiple Demand Forecast Scenarios described in Section 3.6.2. The study is intended to assess how Hydro One Distribution’s overall demand profile may evolve over the longer term under a range of potential policy, technology, consumer behaviour, and electrification outcomes. These scenarios represent alternative pathways toward economy-wide decarbonization by 2050 and reflect varying levels of adoption, achievement of policy objectives, and other factors that could influence future electricity demand.

3.6.3.1 ERM SCENARIO CLASSIFICATION AND METHODOLOGY

ERM developed a scenario-based framework mainly comprising three core scenarios, and two worst-case sensitivities to two core scenarios. The five scenarios modelled are:

- **Business as Usual (Low Ambition – core scenario):** Represents a slow progress toward net-zero in the next 25 years, characterized by continued reliance on fossil fuels and adoption of low-carbon technologies at historical rates. Electrification of heating and transportation, DER uptake, and energy efficiency improvements remain minimal or are a continuation of historic trends.
- **System Transition (Medium Ambition – core scenario):** Envisions significant electrification progress by 2050 with partial reliance on fossil fuels for heating and transportation. Assumes moderate improvements in energy efficiency and balanced DER adoption, including storage.
- **System Transition - Worst Case (worst case sensitivity for System Transition scenario):** Maintains the same electrification level as System Transition but assumes minimum improvements in energy efficiency, limited DER penetration and no incremental demand-side flexibility.
- **Net Zero 2050 (High Ambition – core scenario):** Represents the most aggressive pathway, featuring widespread electrification of heating and transportation, substantial building efficiency improvements, and high DER adoption, including storage.
- **Net Zero 2050 - Worst Case (worst case sensitivity to Net Zero 2050 scenario):** Assumes electrification levels consistent with the Net Zero 2050 scenario but with minimal improvements in energy efficiency, limited DER penetration and no incremental demand-side flexibility.

ERM developed the two worst-case sensitivities to System Transition and Net Zero 2050 scenarios to evaluate the consequences of achieving high electrification alongside minimal improvements in energy efficiency, low DER adoption, and no incremental demand-side flexibility. These sensitivities illustrate the potential system value of demand-side solutions by quantifying the increase in peak demand that could occur if such measures are not available to support the System Transition and Net Zero 2050

electrification pathways. The results demonstrate that demand-side solutions can be effective tools for managing system peak demand by reducing or shifting load during peak periods and, where cost-effective, helping to defer or avoid traditional infrastructure investments. However, the circumstances under which these solutions can provide a cost-effective alternative to traditional infrastructure investments are location-specific and must be assessed on a case-by-case basis in accordance with evolving OEB requirements and policy expectations.

3.6.3.2 ERM STUDY RESULTS

Figure 1 shows the Hydro One distribution peak under each scenario for summer and winter season as identified in the ERM Study.

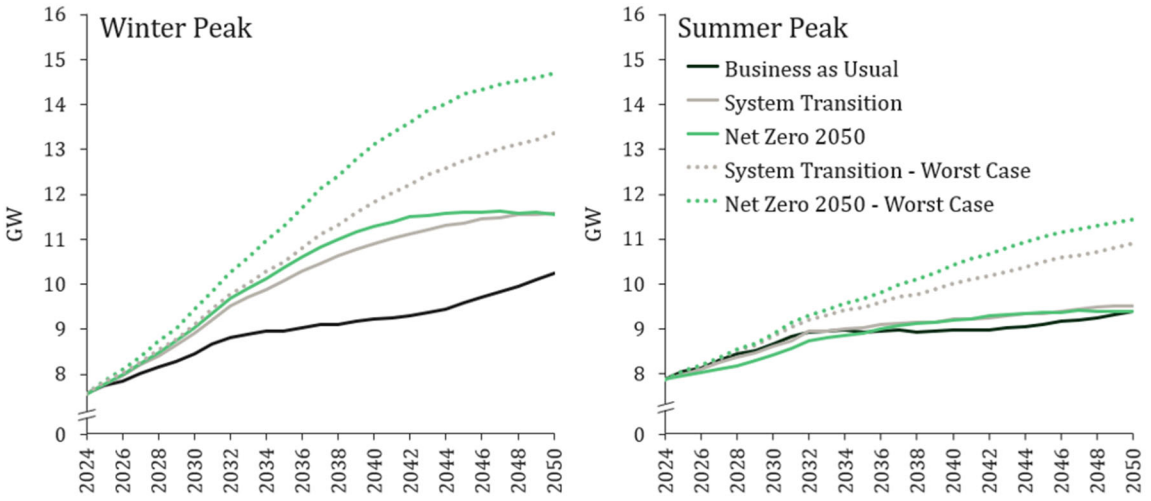


Figure 1: Peak load by scenario and sensitivity for winter (left) and summer (right)

The ERM Study results show that Hydro One's distribution network will likely transition from a summer-peaking system to a winter-peaking system across all scenarios, primarily driven by the electrification of heating. The peak load during winter is highly dependent on thermal energy efficiency improvement programs at all building type levels as well as effective use of flexible demand-side resources. Additionally, summer demand growth is projected to remain relatively consistent across the three core scenarios. While the

System Transition and Net Zero 2050 scenarios experience higher electricity demand due to increased electrification relative to the Business as Usual scenario, much of this additional load is mitigated by demand reduction drivers such as energy efficiency gains, increased DER deployment, and greater demand-side flexibility measures. As a result, summer peak demand shows limited variation across the scenarios despite differing levels of electrification.

The ERM Study provides insights into how electricity demand may evolve under different levels of electrification, shifts in consumer behaviour, and advancements in technology. As shown in Figure 1, peak demand increases across all scenarios over time, with the magnitude of growth determined by the extent to which increased demand from electrification is offset by energy efficiency improvements, DER adoption, and demand-side flexibility.

While the Net Zero 2050 scenario assumes the highest level of electrification, its projected 2050 winter peak demand remains similar to the System Transition scenario because the higher electrification rates are broadly offset by stronger improvements in energy efficiency and higher penetration of behind-the-meter solar and storage. The results thus highlight the important role that energy efficiency measures, DERs and demand-side flexibility can play in moderating future peak demand. The worst-case sensitivities further demonstrates this impact by illustrating how peak demand could increase if electrification proceeds as anticipated but improvements in energy efficiency and other demand reduction measures remain limited.

Hydro One has initiated several strategic investments aimed at reducing local and system peaks to defer or avoid the expansion of existing infrastructure. These investments encompass a range of NWS, including the residential demand response program and the commercial and industrial (C&I) flexibility initiative (refer to Exhibit E-03-02, subsection 2.5.1) and local energy efficiency initiatives (refer to Exhibit E-03-04, subsection 5.0). To support the operationalization of these solutions, Hydro One is also advancing enabling technologies. This includes Grid DERMS and Edge DERMS platforms, which will improve visibility, monitoring, and control of distributed energy resources and flexible loads (see DSP Section

3.11, D-SS-09 for more information on these platforms) as well as real time distribution station and feeder monitoring (see DSP Section 3.11, D-SS-10).

3.6.4 ELECTRIFICATION CONSIDERATIONS

Electrification is an important consideration in Hydro One's distribution system planning. The adoption of electric vehicles ("EVs"), electric space heating, and other forms of electrification affects the distribution system at different levels and over different time horizons. At the system and regional level, electrification contributes to growth in overall electricity demand and may affect the magnitude and timing of future system peaks. At the local level, adoption can result in increased loading on individual stations, feeders, service transformers and secondary infrastructure. As customers rely more and more on electricity for a greater share of their energy needs, maintaining a reliable and resilient grid becomes increasingly important.

Hydro One considered electrification in developing the 2028-2032 Distribution System Plan through: (i) distribution load forecasting activities; (ii) planning of load growth investments; (iii) updating design practices and forecasts for new customer connections and service upgrades; and (iv) assessing the impact of electrification on service transformers. This approach enables Hydro One to respond to electrification at the point where system impacts emerge, while continuing to monitor broader adoption trends and evolving system needs. It also supports prudent infrastructure planning by aligning investments with demonstrated demand and avoiding the construction of capacity materially in advance of need.

3.6.4.1 ELECTRIFICATION IN THE LOAD FORECAST

Hydro One's distribution load forecast incorporates both expected impacts of electrification and traditional economic and demographic drivers. As described in Exhibit D-03-01, Hydro One's forecasting methodology draws on both econometric and end-use approaches to understand how electricity demand is expected to evolve as the economy, technology and consumer behaviour change over time. The econometric approach considers statistical relationships between electricity demand and changing economic and demographic

variables, while end-use considerations provide information on how electricity use is changing, including in response to evolving technologies and key government policies.

As further described in Exhibit D-05-01, Hydro One supplements its traditional load research and forecasting activities with its Next Generation ("NG") End-Use Analysis, which focuses on principal sources of future load growth arising from electrification. This includes emerging technologies and applications such as EVs, heat pumps and electric space heating, transportation electrification and industrial electrification. The analysis draws on observed load trends, technology adoption patterns, market developments, customer information, Hydro One's load research and relevant electrification policies.

The NG End-Use Analysis is used as a supplementary forecasting tool rather than as a separate forecast. Its results are considered alongside Hydro One's econometric forecasting methodologies in the development, interpretation and validation of the distribution load forecast. Estimates of emerging electrification impacts are also periodically reviewed against observed load data and other available information. These activities provide additional insight into emerging load drivers that may not yet be fully reflected in historical demand trends and support Hydro One's load forecasting, system planning and investment decision-making.

3.6.4.2 ELECTRIFICATION IMPACTS ON LOAD GROWTH INVESTMENTS

Hydro One considered electrification in the identification of capacity-driven investments under DSP Section 3.11, D-SS-01 System Upgrades Driven by Load Growth and GSP Section 4.11, G-GP-22 Distribution Capital Contribution to Hydro One Transmission. As described in Exhibit D-05-01, the impact of EV and heat pump adoption have been incorporated into the load forecasts used to support capacity planning in addition to other information that informs localized distribution capacity assessments (See DSP Section 3.11, D-SS-01).

3.6.4.3 ELECTRIFICATION IMPACTS ON NEW CONNECTIONS AND SERVICE UPGRADES

Hydro One has analyzed the impacts of EV charging and heat pump adoption to ensure that assets installed through new connections and service upgrades can accommodate future load requirements.

Service upgrade volumes are expected to continue growing over the 2028-2032 period (see DSP Section 3.11, D-SA-02 for details). As described in Exhibit D-05-01, Hydro One's recent experience indicates that EV chargers and heat pump systems are contributing to an increase in service upgrade activity.

Analysis of residential customer loading indicates that EV charging and heat pump adoption will increase individual customer demand and may, in some cases, result in the need for larger service transformers, secondary bus infrastructure, service conductors, or additional transformer capacity. To ensure newly installed assets can accommodate anticipated electrification-related loads over their expected service lives, Hydro One has updated its design practices to reflect increasing residential customer load resulting from at-home EV charging and heat pump systems.

These changes are reflected in the DSP Section 3.11, D-SA-02 New Load Connections, Upgrades and Cancellations. The proposed investment is necessary to enable Hydro One to continue meeting its customer connection and service upgrade obligations while ensuring new infrastructure is appropriately sized to accommodate future growth in electrification-related demand.

3.6.4.4 ELECTRIFICATION IMPACT ON SERVICE TRANSFORMERS

Hydro One monitors EV adoption trends, tracks EV-related load growth, and analyzes residential charging behaviour. This work includes evaluating charging patterns, charging timing, charging diversity, and the coincidence of EV charging with existing customer demand. These analyses provide Hydro One with a more refined understanding of how electrification may affect distribution system loading and asset utilization.

Service transformers are among the first distribution assets affected by electrification because EV charging can materially increase residential customer demand and create localized capacity constraints. To assess these impacts, Hydro One used the Electric Power Research Institute's ("EPRI") Hotspotter tool, which combines smart meter data, EV charging assumptions, and probabilistic charging behaviour models to identify service transformers at increased risk of overload as EV adoption grows. This analysis helps Hydro One identify where electrification-related capacity constraints are most likely to emerge and support planning of future transformer replacements and upgrades.

The results of this work are reflected in the Secondary Electrification Program within DSP Section 3.11, D-SS-01. Through this program, Hydro One proposes targeted investments to address service transformers identified as having a high risk of overload due to increasing EV adoption. This approach enables Hydro One to focus investments where electrification impacts are expected to emerge, supporting reliable customer service while efficiently managing capital expenditures.

3.6.5 NON-WIRES SOLUTIONS TO ADDRESS SYSTEM NEEDS

Non-Wires Solutions (NWS) involves the application of non-traditional measures to defer or avoid infrastructure investments. Conventional "wires" infrastructure is required because system loading exceeds an asset's capacity during peak-demand periods. Where the underlying system need occurs during discrete periods and can be reliably addressed by reducing, shifting or locally supplying demand, an NWS may be a viable alternative. NWS can include, but is not limited to, measures such as demand response (thermostat control, energy storage, managed EV charging, commercial and industrial (C&I) load flexibility), and Energy Efficiency (EE).

Hydro One has integrated the consideration of NWS into its 2028-2032 distribution system planning process, consistent with the OEB's NWS Guidelines and BCA Framework. Hydro One's NWS assessment process evaluates the suitability of an NWS by comparing it against the "wires" alternative with respect to identified system needs, timing, and cost-effectiveness.

Hydro One's approach has been informed by experience gained during the current rate period and by the development of the capabilities required to identify, acquire and dispatch distributed resources. The application of this approach to the 2028-2032 investment plan identified 16 load-growth projects for which NWS are expected to defer approximately $103M of conventional infrastructure investment beyond the 2028-2032 period. In addition, there is one load growth project, "Kashabowie HVDS", that NWS is anticipated to defer from 2028 to a 2031 in-service date.

The following sections describe the NWS resources and capabilities developed during the current rate period, the process used to evaluate whether NWS can reliably and cost-effectively address identified distribution system needs, and the results of applying that process to the 2028-2032 investment plan. The final section within the NWS discussion explains how Hydro One will scale and operationalize NWS within the 2028-2032 rate period.

3.6.5.1 NWS EXPERIENCE AND RESOURCES

Hydro One's approach to NWS has been informed by experience gained through several initiatives during the current 2023-2027 rate period. These initiatives have provided practical information on the ability of different resources to address distribution system needs, including their technical performance, customer participation, dispatchability and interaction with other market programs. This experience, together with Hydro One's developing EE activities, provides a portfolio of resources that can be considered when system planning identifies a need that may be suitable for an NWS.

One example is the use of a Mobile Battery Energy Storage System (MBESS) to address peak demand loading on the Shabaqua DS F1 feeder. This feeder experiences low voltage due to peak demand loading that occurs exclusively on weekends in the summer months. The length of the Shabaqua DS F1 feeder limits the viability of typical lines solutions, for example, implementing voltage conversion or one-phase to three-phase conversion would come at a significant cost and without a meaningful capacity increase. While a new high-voltage distribution station (HVDS) at the load centre would satisfy the

system need and will eventually be required to accommodate continued growth, it comes at a cost similar to the line conversion mentioned above and thus an NWS was preferred for as long as technically feasible. The chosen solution is an NWS in the form of an MBESS that is installed at the start of the summer season by a third-party provider and is subsequently removed at the end of the summer season. The MBESS injects energy during peak loading periods to improve voltage performance and then recharges as loading subsides. The installation of the MBESS has allowed Hydro One to defer the need for the HVDS wires solution to a later year in the 2028-2032 rate period (see DSP Section 3.11, D-SS-01, S-01.102 “Kashabowie HVDS”).

Hydro One has also gained experience with a commercial and industrial (C&I) flexibility initiative. This initiative involved the registration of third-party dispatchable resources to an online platform and the provision of incentive payments to dispatch more than 30MWh during predicted peak periods throughout the summer of 2025. This initiative provided key insights into the benefits and challenges of flexible resources based on the type of customer, the type of DER being used, and the influence of external market forces such as the IESO’s Industrial Conservation Initiative (ICI), which can significantly influence customer willingness to respond to a Hydro One activation. Hydro One will continue to develop and expand its C&I flexibility capability.

For residential customers, Hydro One launched its demand response (DR) program in 2023. As of Q2 2026, approximately 29,000 behind-the-meter (BTM) devices, including smart thermostats, electric vehicles (EVs), EV chargers and home batteries, were enrolled, collectively providing approximately 20 MW of dispatchable capability. Hydro One has conducted more than 300 distinct DR events since inception to assess the performance and grid value of different resource types and inform the cost-effective scaling of the program. Further details regarding the costs associated with acquiring residential DER resources through the DR program see Exhibit E-03-02, Section 2.5.1.

Hydro One’s experience with these initiatives has informed the development of a broad portfolio of resources that may be used to address identified distribution system needs.

Depending on the characteristics of the local constraint and the achievable potential within the affected area, an NWS may use a combination of resources, including residential DR, C&I flexibility, energy storage and targeted energy efficiency measures.

Looking forward, and beginning in 2027, Hydro One anticipates its Energy Efficiency (EE) program will provide an additional source of peak-demand reduction, by offering top-up incentives in select areas to improve upon existing IESO programs. EE empowers customers to make smarter choices to manage energy affordability while producing system benefits in areas where peak demand loading has been identified as a system need. A portion of EE program expenditures will be directed to areas of Hydro One's service territory identified for NWS implementation. Peak demand savings from EE will be achieved through customer participation in "Stream 1" and "Stream 2" programs and will contribute a portion of the peak demand reductions required as an overall NWS. "Stream 1" programs, which include province-wide Save on Energy programs, are recoverable by the Independent Electricity System Operator (IESO), and "Stream 2" programs, which are LDC-led, are funded by Hydro One, with the potential for IESO co-funding. Details on Hydro One's EE program can be found in Exhibit E-03-04, Section 2.4.1.

Collectively, these resources provide Hydro One with a range of potential measures that can be considered where an identified distribution system need is suitable for an NWS. The appropriate resource mix will depend on the magnitude, timing and duration of the system constraint, the characteristics of customers and loads within the affected area, and the amount of resource capability that can reasonably be acquired. These considerations are incorporated into the NWS assessment process described in Attachment 1.

3.6.5.2 2028-2032 NWS ASSESSMENT PROCESS

Hydro One considers NWS as part of its investment planning process. The objective of the NWS assessment process is to identify system needs for which demand reduction, load shifting, storage or other distributed resources can reasonably be used to defer or avoid the conventional infrastructure investments.

NWS are particularly applicable to capacity-related system needs where forecast demand is expected to exceed the capacity of existing infrastructure during peak periods. Accordingly, in the 2028-2032 DSP, Hydro One's NWS assessment is focused principally on load-growth investments identified through DSP Section 3.11, D-SS-01 System Upgrades Driven by Load Growth, where an NWS may be capable of reducing peak demand sufficiently to defer the conventional wires solution.

Once a system need has been identified through Hydro One's planning process, the potential NWS alternative is assessed through a staged NWS assessment process. At a high level, Hydro One considers:

1. Whether the underlying investment need can, in principle, be addressed through an NWS;
2. Whether the project meets applicable materiality, timing and capacity-related screening criteria;
3. Whether an NWS appears technically and economically viable based on the magnitude of the system constraint;
4. Whether sufficient NWS potential can reasonably be acquired within the affected area; and
5. Whether the NWS is cost-effective relative to the conventional wires alternative under the OEB's BCA Framework.

This staged approach allows Hydro One to focus detailed technical and economic analysis on system needs for which an NWS has a reasonable prospect of providing a viable alternative to conventional infrastructure. The detailed screening criteria, technical and economic considerations, achievable potential study and BCA are provided in Attachment 1 – Non-Wires Solutions Assessment Process.

3.6.5.3 2028-2032 INVESTMENT PLAN NWS IMPACTS

Application of Hydro One's NWS assessment process resulted in 16 projects for which NWS are expected to defer conventional infrastructure investment beyond the 2028-2032 period. These projects represent approximately $103M in deferred capital expenditures. The associated wires investments are identified separately in DSP Section 3.11, D-SS-01, together with the NWS projects selected through the process. In addition to these 16 deferrals beyond the 2028-2032 period, there is one load growth project, "Kashabowie HVDS", that NWS is anticipated to defer from 2028 to a 2031 in-service date.

For these projects, Hydro One assessed the underlying system need, the conventional wires alternative, the technical potential for NWS resources to address the need and the economic comparison between the NWS and wires alternatives. The supporting project-specific evidence is provided in the appendices to Attachment 1 and includes an NWS Summary, the supporting BCA spreadsheet, and the applicable Posterity Group Achievable Potential Study.

These results reflect the NWS process at the time the investment plan was finalized. The suitability and cost of an NWS can change as the underlying system need develops and as additional information becomes available. In particular, actual load growth may materialize faster or slower than forecast; the amount and cost of NWS resources that can be acquired may differ from the assumptions used in the planning assessment; customer participation may vary; and changes in technology, market conditions or public policy may affect the availability or economics of particular NWS resources.

As a result, the mix of wires and non-wires solutions may need to change during the rate term. For example, an NWS selected to defer a wires investment may no longer provide sufficient capability if load growth accelerates beyond what the NWS can address, requiring the conventional investment to proceed. Conversely, where load growth develops more slowly than forecast or additional NWS capability becomes available, a wires investment included in the capital plan may subsequently be deferred through an

NWS. New system needs may also arise during the rate term for which an NWS is determined to be the preferred solution.

These changes can affect both capital and OM&A expenditures. NWS implementation may require customer and DER acquisition incentives, ongoing participation or OEM fees, flexibility payments and other operating costs required to acquire and maintain the resources necessary to achieve the planned deferral. Conversely, where an NWS replaces a capital project included in the approved plan, the associated capital revenue requirement would no longer be required.

Given this uncertainty, the evolving application of NWS, and the potential for additional opportunities to leverage non-wires options during the rate term, Hydro One is proposing a Non-Wires Solutions Implementation Cost Variance Account to provide the regulatory treatment necessary to reflect changes between wires and non-wires solutions during the 2028-2032 rate term. As further described in GSP Section 4.11, G-GP-03, section 9.4, the proposed account would capture: (i) the revenue requirement impact throughout the 2028-2032 rate term associated with (a) replacing a planned capital (wires) project with NWS; (b) converting a planned NWS project to a capital (wires) project, if warranted; and (c) new NWS projects that arise; (ii) incremental net OM&A expenditures incurred over the 2028-2032 rate term required to implement and operate NWS to offset capital projects; and (iii) Margin on Payments (MoP) incentives associated with payments made to the third-party-owned DERs for the services identified in this Application.

Hydro One will continue to monitor the underlying system needs, load growth, resource acquisition and performance of NWS throughout the rate term and will update the implementation of individual NWS projects as circumstances evolve. This approach allows Hydro One to continue pursuing cost-effective capital deferrals while retaining the flexibility to proceed with conventional infrastructure where an NWS can no longer reliably or economically address the identified system need. Similarly, Hydro One will continue to evaluate capital projects for NWS opportunities and will convert capital projects to NWS projects where viable and cost-effective.

3.6.5.4 OPERATIONALIZING NWS OVER THE PLAN

Expanding the use of NWS requires grid-management capabilities necessary to monitor, coordinate and dispatch distributed resources when an identified system need occurs. Hydro One has begun developing these capabilities and will continue to implement them within the 2028-2032 rate period.

As NWS deployment expands, Hydro One will increasingly need to coordinate a diverse portfolio of distributed energy resources with different operating characteristics, availability and customer participation requirements. While individual NWS initiatives can be supported through program-specific platforms and operating arrangements, coordinating distributed resources across a large distribution system at scale requires greater automation, system visibility and integration.

In addition to supporting project-specific NWS deployments, Hydro One's residential Demand Response (DR) and Local Energy Efficiency programs provide standalone distribution system benefits and have been demonstrated to be cost-effective through cost-benefit analyses for each program. The analysis shows that both the residential DR and Local EE programs have a cost-benefit ratio greater than one based on the Distribution System Test and Energy System Test. The supporting analysis for these non-targeted NWS programs is provided in Attachment 1, Appendix A, with the associated benefit-cost analyses calculations included in Attachment 1, Appendix B. By developing and maintaining a portfolio of dispatchable and energy-saving resources across Hydro One's service territory, these programs enable Hydro One to respond more effectively when localized capacity needs arise. Maintaining these programs at scale is therefore a key component of Hydro One's NWS strategy, providing both ongoing grid benefits and an established pool of resources that can be leveraged as part of future NWS deployments.

Hydro One's Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS) will provide important enabling capabilities for the future implementation and expansion of NWS. These technologies will support the

monitoring, forecasting and coordination required to use distributed resources to address localized distribution system constraints.

A key consideration in using NWS to address capacity-related system needs is dispatchability. This requires the coordination of DER on a specific day, time, and duration. Implementing this level of dispatchability requires a multi-step process of forecasting an overload condition up to 48 hours in advance, real-time identification of the overload condition, communication to distributed resources that can mitigate the overload, then follow-up measurement and verification to confirm the desired outcomes were achieved.

Hydro One currently uses program-specific capabilities to support existing NWS initiatives. However, the broader integrated capability required to coordinate an expanding portfolio of distributed resources across the distribution system is still being developed. ADMS and DERMS are expected to provide this scalable capability once implemented and integrated. Additional details on ADMS, DERMS, and the benefits offered from these foundational technologies, can be found in DSP Section 3.11, D-SS-09 Intelligent Grid Platform.

3.6.6 CLIMATE VULNERABILITY ASSESSMENT AND SYSTEM HARDENING

The OEB's Chapter 5 Filing Requirements requires distributors to assess the vulnerability of their distribution systems to extreme weather and climate-related events, undertake a pre-assessment to identify technically and economically feasible system-hardening opportunities, and complete a benefit-cost analysis ("BCA") where potentially suitable resilience investments are identified. The OEB's VASH framework is intended to complement existing planning processes by incorporating resilience considerations alongside other planning inputs such as asset condition, historical performance and other capital plans.

Hydro One retained Guidehouse Canada Ltd. ("Guidehouse") to undertake the Vulnerability Assessment and System Hardening ("VASH") analysis as an input to the development of the 2028-2032 Distribution System Plan. An overview of the study

methodology and principal findings is provided in DSP Section 3.3, subsection 3.3.2.5, and the complete Guidehouse VASH Study is provided as Attachment 5 to that section.

This section focuses on the application of the three VASH planning steps: Vulnerability Assessment, Pre-Assessment and BCA, and how the resulting information was integrated with Hydro One's established investment planning processes.

The VASH analysis provides an additional forward-looking climate-vulnerability assessment and a common framework for evaluating the resilience benefits of potential system-hardening measures. Guidehouse describes the VASH analysis as an input to Hydro One's planning process that can assist planners in targeting resilience improvements to locations where they can provide greater customer value.

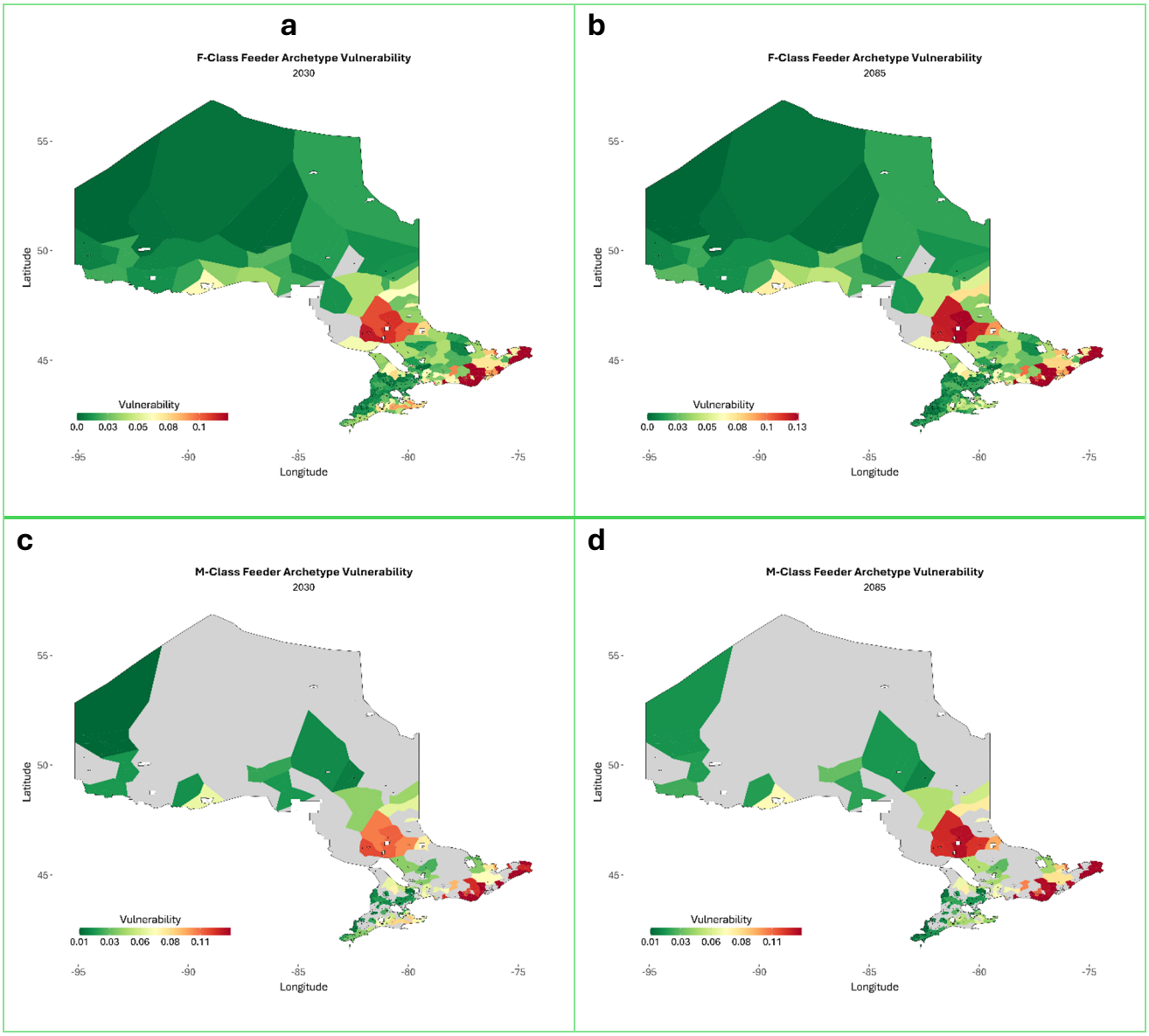
3.6.6.1 VULNERABILITY ASSESSMENT

Guidehouse completed the Vulnerability Assessment using a custom option of the OEB's VASH Toolkit. The customized approach retained the Toolkit's underlying analytical logic, including asset classification, location-specific climate exceedance probabilities and the use of projected climate conditions, while adapting the analysis to Hydro One's large and geographically diverse distribution system.

The assessment considered the two climate perils for which the OEB Toolkit provides projected return intervals and which Hydro One identified as principal weather-related drivers of force-majeure outages: high wind and ice accretion. The analysis focused on wood poles and overhead conductor and differentiated asset sub-classes based on characteristics affecting fragility, including pole class and condition, vegetation environment and road access.

More than 3,200 Hydro One feeders were grouped by feeder class and Hydro One operating region and mapped to OEB/ECCC climate locations. Guidehouse developed 327 Feeder Archetypes representing combinations of feeder group and climate location and ranked their relative vulnerability under the RCP 6.0 climate scenario. The

Vulnerability Assessment provides a relative ranking of vulnerability rather than an absolute determination that an investment is required at a particular location. Customer consequence and the potential value of mitigating the identified vulnerability are introduced through the subsequent Pre-Assessment and BCA.



Relative vulnerability of F- (panels a and b) and M-Class (panels c and d) Feeder Groups in 2030 and 2085 under RCP 6.0. Feeders are mapped to the substation at the head, gray areas indicate no mapped substation. a) 2030 F-Class vulnerability. b) 2085 F-Class vulnerability. c) 2030 M-Class vulnerability. d) 2085 M-Class vulnerability.

Figure 2: Relative Vulnerability of F- and M-Class Feeder Groups in 2030 and 2085 under RCP 6.0

The Vulnerability Assessment identified meaningful geographic differences across Hydro One's service territory. As shown on Figure 2, Distribution (F-Class) and Subtransmission (M-Class) feeders in the East region exhibit the highest relative climate vulnerability,

reflecting the combination of projected wind and ice-accretion severity and vegetation exposure. Higher vulnerability also occurs in portions of the near-North, including the Sudbury, North Bay and Espanola climate regions, and in portions of the Central region along the north-eastern shore of Lake Ontario. The South region is relatively less vulnerable at present and is projected to become relatively less vulnerable over time as the severity of ice accretion shifts northward.

3.6.6.2 PRE-ASSESSMENT OF SYSTEM-HARDENING MEASURES

Following completion of the Vulnerability Assessment, Guidehouse undertook the Pre-Assessment required by the OEB VASH framework. The purpose of this step was to translate the system-wide vulnerability results into a more targeted assessment of locations and resilience measures that could reasonably proceed to BCA.

The Pre-Assessment involved three principal steps. First, Guidehouse translated the Feeder Archetype results to an individual-feeder vulnerability ranking. The forward-looking vulnerability score was combined with observed 2021-2025 force-majeure outage experience and customer impact, including the number of customers served and customers historically affected by force-majeure outages. This introduced both observed system performance and customer consequence into the forward-looking climate assessment.

Second, Hydro One's engineering and planning analyses were used to identify candidate feeders for resilience measures where additional system-specific information was required. In particular, Hydro One provided candidate feeder groups for Selective Undergrounding, Sectionalization and Voltage Conversion with Sectionalization. This ensured that the VASH analysis considered not only relative climate vulnerability but also whether the system configuration made a particular measure technically applicable.

Third, Guidehouse grouped candidate feeders into Average Program Feeders ("APFs") for BCA. APFs were designed to test the economics of applying similar resilience measures to groups of comparable needs. Within each resilience measure and feeder

class, progressively more targeted APFs were developed by focusing on increasingly vulnerable feeders. This allowed the analysis to assess whether customer value increased as each resilience measure was directed toward locations with greater vulnerability and customer consequence. The Guidehouse analysis developed 27 APFs across the five resilience measures.

This approach is consistent with the OEB's expectation that a BCA may support a program addressing multiple similar needs at different locations, while ensuring that the assessment remains sufficiently targeted to the underlying system vulnerabilities.

3.6.6.3 BENEFIT-COST ANALYSIS

The Pre-Assessment resulted in five resilience measures being evaluated through BCA:

- Clustered Hardening;
- Covered Conductor;
- Selective Undergrounding;
- Sectionalization; and
- Voltage Conversion and Sectionalization.

Guidehouse completed the BCAs in a manner consistent with the OEB's VASH and BCA frameworks. The analysis quantified customer resilience benefits associated with reducing the frequency or customer impact of force-majeure outages. Projected outage frequency was calibrated to Hydro One's observed 2021-2025 force-majeure outage history, and customer outage impacts were valued using the Lawrence Berkeley National Laboratory ICE calculator.

The analysis intentionally did not quantify normal-day reliability benefits. It also did not assume future customer growth, and Guidehouse identified limitations associated with applying the ICE Value of Lost Load estimates to lengthy, widespread extreme-weather events. These considerations are important when interpreting the Benefit-Cost Ratios (BCRs): the results provide a resilience-specific assessment and are not intended to

represent every potential customer benefit associated with the measures. The BCA results are presented in Table 3.

Table 3 - Guidehouse VASH BCA Results

Resilience Measure	VASH BCA Result	Planning Interpretation
Clustered Hardening	BCRs increased as the analysis focused on more vulnerable feeders, reaching approximately 0.94 for the most targeted F-Class and M-Class APFs.	Provides strong resilience support for targeted replacement where poor-condition poles and higher climate vulnerability coincide. Reliability benefits, where applicable, are additional to those quantified by VASH.
Covered Conductor	BCRs for all APFs were at or below 0.1 based on resilience benefits.	Does not support broad use of covered conductor as a resilience-driven investment under the VASH assumptions. Other reliability applications may still be considered independently.
Selective Undergrounding	BCRs reached approximately 0.49 for F-Class and 0.43 for M-Class APFs.	The analysis could not distinguish the highest-risk short conductor segments within feeders and excluded normal reliability benefits. Accordingly, the result is most appropriately used as an input to more targeted project selection.
Sectionalization	BCRs reached approximately 0.95 for the most targeted F-Class APF and 0.73 for the most targeted M-Class APF under the base adjacent-feeder assumption.	Indicates significant resilience value where sectionalization is applied to appropriately selected vulnerable feeders. Reliability benefits are additional to the resilience benefits quantified by VASH.
Voltage Conversion + Sectionalization	BCRs ranged from 0.45 to 0.98 across F-Class APFs. The BCA included only the costs of the added sectionalization work, but excluded the costs of voltage conversion.	Indicates that where voltage conversion is independently justified, adding sectionalization, including new tie points, may provide additional resilience value at relatively low incremental cost.

3.6.6.4 INTEGRATION OF VASH RESULTS INTO THE DISTRIBUTION SYSTEM PLAN

Hydro One incorporated the VASH results into its established investment planning process together with asset condition, historical reliability and force-majeure performance, road access and restoration difficulty, customer consequence, system configuration, engineering feasibility and the costs and benefits of available alternatives, and other asset and system needs. In this way, VASH provides an additional forward-looking resilience consideration within Hydro One's broader asset management and investment planning processes.

This integration is reflected most directly in investments such as DSP Section 3.11, D-SR-07 Pole Sustainment and DSP Section 3.11, D-SR-14 Selective Undergrounding, where asset condition and other established planning needs are considered together with climate vulnerability and resilience benefits. For clustered hardening, the VASH analysis demonstrates that resilience value increases when stronger replacement poles are targeted to more vulnerable feeders. For selective undergrounding, the VASH analysis provides a system-level indication of resilience value, while Hydro One's project-selection process applies more granular asset, vegetation, outage-performance and customer-consequence information to identify the specific high-consequence sections where undergrounding is most appropriate. Guidehouse's BCA assessed average candidate feeder segments and could not isolate the highest-risk short conductor sections. Hydro One therefore uses the VASH result as one input to project-specific planning.

Similarly, sectionalization and voltage conversion opportunities are considered where the underlying system configuration and other planning needs support the investment. The VASH analysis provides additional information regarding the potential resilience benefits of these measures, but it is not the primary basis for the associated investments. Covered conductor was not identified by the VASH analysis as a preferred system-hardening measure on resilience benefits alone, which supports Hydro One's decision not to rely on a broad covered-conductor program as the principal response to climate vulnerability.

Overall, VASH supported Hydro One's established investment planning process through a structured approach to incorporating climate considerations into investment decisions. The Vulnerability Assessment identified areas of relatively greater climate vulnerability, the Pre-Assessment focused attention on technically plausible resilience opportunities, and the BCA evaluated the potential customer value of applying different resilience measures to increasingly targeted groups of feeders. Together, these steps provided a common framework for identifying climate vulnerabilities, assessing resilience opportunities, and evaluating customer value. The resulting insights were integrated into the development of the 2028-2032 DSP through Hydro One's established process, without creating a separate capital envelope or a stand-alone investment determination. In determining the final investment portfolio, Hydro One considered the VASH results alongside other DSP inputs, including asset information, system and operational needs, customer needs and preferences, as well as external and other influences while balancing consideration for affordability.

3.6.7 DISTRIBUTION SYSTEM LOSSES

Hydro One considers electrical distribution losses through its planning, design, and procurement practices. Loss considerations are incorporated into transformer procurement, voltage conversion initiatives, conductor sizing practices, capacitor placement, and system investments to meet broader system needs. While these activities are primarily undertaken to meet other system needs, they also reduce technical losses across the distribution system.

Distribution losses represent the difference between the total amount of energy delivered into the distribution system and the energy ultimately billed to end-user customers. These losses fall into two categories: technical losses (such as conductor I^2R heating and transformer core losses), and non-technical losses (such as metering discrepancies or other factors).

This evidence focuses on technical losses, which mainly arise from two sources: Transformers and Distribution Line Conductors.

Transformers: Transformers experience two main types of losses during normal operation: No-load losses and load losses. No-load losses occur when a transformer is energized, regardless of whether it is supplying any customer load. These losses are caused by the magnetizing current to energize the transformer core. Load losses occur when current flows through the transformer winding to serve customer demand. In most distribution transformers, no-load losses represent a significant portion of total transformer losses because they occur 24 hours-a-day, even under light-load or no-load conditions. These losses cannot be avoided and always exist.

Distribution Line Conductors: Line losses occur along the conductors that carry electricity from the transmission system through the sub-transmission, primary distribution and secondary networks to end-use customers. As power flows from source to the load, energy is dissipated as heat in the line conductors, making line losses the largest contributor to total distribution losses. The losses incurred depends on the conductor's resistance, the magnitude of current flowing through it, and the total 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.

As part of the Settlement Agreement in EB-2021-0110, Hydro One agreed to undertake a review of distribution loss evaluation practices used by other North American utilities, with the objective of identifying recommendations (if any) to cost-effectively reduce losses across its system. To fulfil this commitment, Hydro One engaged an independent third-party expert, Electrical Power Research Institute (EPRI), to undertake a comprehensive review of distribution loss reduction practices.

In its study, EPRI used a multimethod approach that combined a survey of distribution loss management practices from North American utilities with detailed power system simulations performed using Hydro One's distribution system models.

Twenty-two North American utilities participated in the survey conducted by the EPRI. The objective of the survey was to identify active loss-reduction programs deployed by various

utilities and to understand the underlying drivers and benefits achieved as part of those programs.

EPRI also conducted a series of detailed power flow simulations using representative Hydro One feeders across multiple voltage classes and a range of initial operating conditions. These simulations provided a standardized analytical basis for evaluating distribution loss reduction benefits. EPRI study is provided in DSP Section 3.3, Attachment 4.

The EPRI Study outlines a range of potential approaches for reducing distribution technical losses. Importantly, the survey and accompanying technical analysis indicate that line loss reduction is rarely the primary driver of distribution investment. Rather, loss reduction is generally an ancillary benefit of investments undertaken to address other system needs, including reliability, capacity, asset renewal and voltage performance. Accordingly, the study confirms that loss reduction is almost always pursued as secondary (but valuable) benefit.

Hydro One has implemented a number of practices through which distribution loss reduction is achieved as a secondary benefit. These practices are incorporated into design and material standards, asset procurement processes, and system planning practices. These initiatives are listed below:

- 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 promotes cost-effective future conversion of lines to higher voltages without requiring a rebuild of poles, insulators, and other associated hardware. Conversions to higher voltages result in reduced line current to deliver the same amount of power, which reduces losses.

- Hydro One's overhead distribution standards specify the use of 3/0 ACSR (medium-sized wire) as minimum size for all newly constructed 3-phase overhead distribution feeders. For the sub-transmission feeders, use of 556AL (larger-sized wire) is recommended, especially close to the Transformer Station. 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 reliability or capacity capital projects where new conductor is being installed.
- Hydro One has recently adopted a key recommendation from the EPRI Study by leveraging system simulation software tools as part of its system planning practices to determine the placement of capacitor banks on the distribution system. When additional capacitor banks are required to support feeder voltage profiles, this analytical tool allows planners to systematically determine the optimal locations and sizes of installations based on defined input parameters, ensuring the primary objective of voltage regulation is met while also delivering the secondary benefit of loss reduction.
- During the 2028-2032 period, Hydro One will continue to realize loss-reduction benefits through investments undertaken to address broader system needs. Examples include: Distribution Station Renewal and Voltage Consolidation (DSP Section 3.11, D-SR-04 and D-SR-17): These investments seek to address asset condition by removing or replacing assets where prudent. This involves upgrading or removing stations driven by poor asset condition through voltage conversion or other means. Loss-reduction is expected when a stage of transformation is removed under distribution station renewal and when distribution transformer replacement increases feeder voltage under voltage consolidation. For example, if load serviced by 4.16kV distribution station is being served at higher distribution voltage level, the reduced line current will reduce losses.
- System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01): Load growth investments increase system capacity to accommodate growth and new connections. In many cases, these projects also reduce losses by transferring load from overladed assets to new or underutilized assets. Although the total load

served by the system remains same, splitting the load between two assets reduces the current flowing through overloaded asset, resulting in a net reduction in losses. This is because losses are proportional to the square of current (I^2R) and even modest reductions in current produce disproportionately larger reductions in losses. For example, taking the same amount of load and splitting it over two feeders with the same characteristics achieves approximately 50% reduction in line loss. Additionally, many of these investments also involve installing larger conductors with lower electrical resistance, which reduces losses and improves overall system efficiency. Some load growth investments also increase system capacity through voltage conversion, which reduce the current required to deliver the same amount of power and therefore provide additional loss reduction benefits, as discussed in the previous section.

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Section 3.6 – Attachment 1 – Non-Wires Solutions Assessment Process

1.0 PURPOSE

Hydro One has integrated NWS assessment into its distribution investment planning process to determine whether qualifying system needs can be addressed through demand reduction, load shifting, Distributed Energy Resources (DERs) or other non-wires solutions in lieu of or to defer traditional infrastructure investment.

This Attachment describes the staged process Hydro One applied in developing the 2028-2032 Distribution System Plan (DSP). The process is intended to progressively focus on detailed analysis on investments for which an NWS can reasonably address the underlying system need and has a reasonable prospect of being cost-effective.

Hydro One's NWS assessment process consists of five gates outlined in Figure 1 below, which provides a general overview of the process. Gates 1 through 3 collectively constitute Hydro One's NWS pre-assessment process, consistent with the OEB NWS Guidelines.[1] The pre-assessment progressively evaluates the applicability, technical viability and high-level economic feasibility of potential NWS before more detailed analysis is undertaken. Projects that remain viable following pre-assessment proceed to Gate 4, which assesses the achievable NWS potential within the affected area, and Gate 5, which applies the OEB BCA Framework to compare the NWS with the traditional infrastructure investment.

NWS Project-specific evidence supporting Gates 4 and 5 is provided in the appendices to this Attachment.

[1] OEB Non-Wires Solutions Guidelines for Electricity Distributors, July 7, 2026.

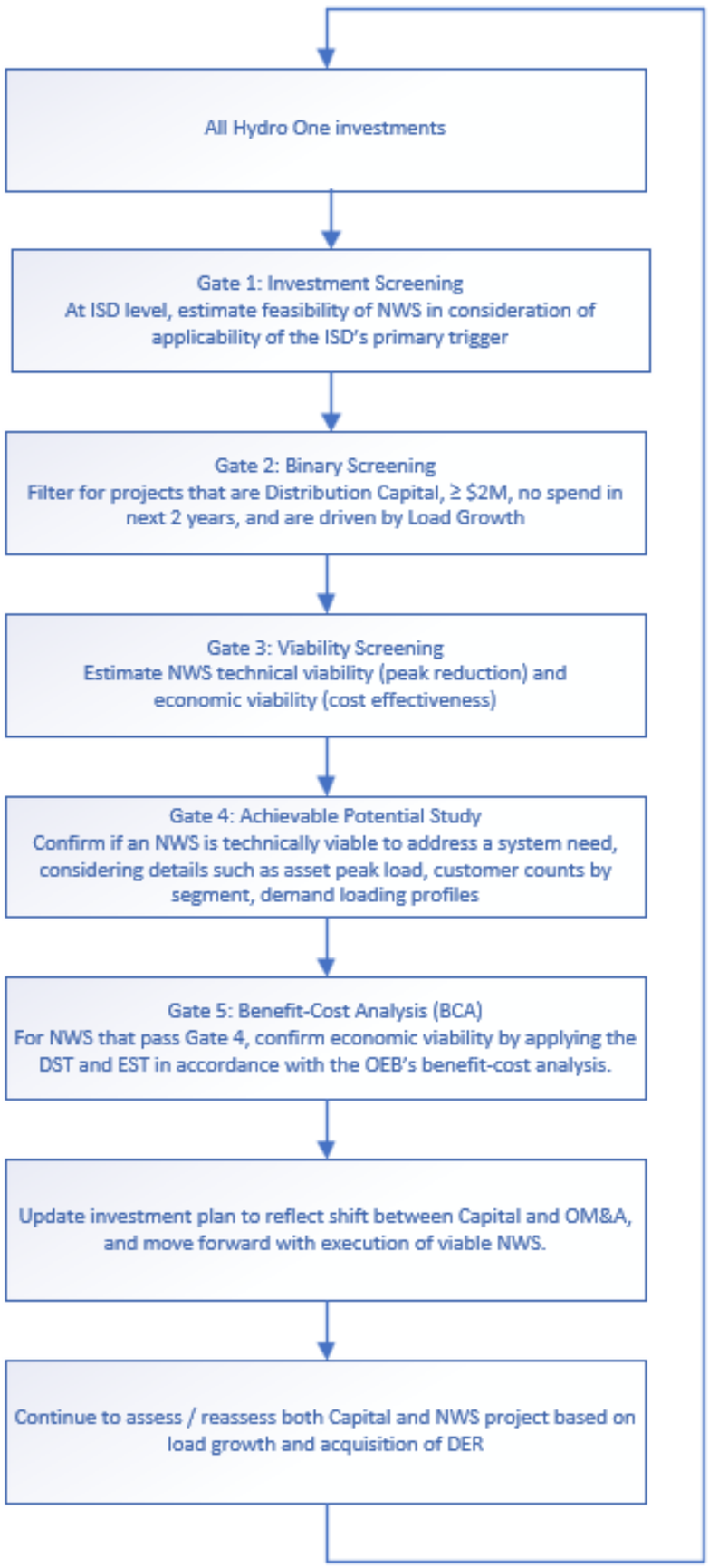


Figure 1: Hydro One's NWS Assessment Process

2.0 GATE 1: INVESTMENT SCREENING

Investments are screened at the ISD level by their primary trigger to determine whether an NWS could address the underlying system need. Investments are screened out where the required outcome cannot be achieved through demand reduction, load shifting, distributed energy resources, or other non-wires measures.

An investment is **not considered suitable for NWS** where the primary need is related to:

- Asset condition, as investments within the System Renewal category are not considered for NWS due to the inability of NWS to address a condition-based need.
- Mandated LDC obligations not directly related to the delivery of electricity, including investments such as joint use or broadband.
- Metering, protection, outage response, or power restoration operations where NWS cannot perform the required function.

An investment is considered potentially suitable for NWS where the need is primarily driven by capacity constraints, and where an NWS could reasonably reduce, shift, or manage load to defer or avoid the need for a traditional wires solution.

Twenty-six investments under the System Service, System Renewal and System Access investment categories within the current DSP were screened out at Gate 1 because the underlying needs could not reasonably be addressed through an NWS based on the above criteria.

Hydro One also considered two ISDs for which an NWS may appear conceptually applicable, but which were ultimately not advanced through the NWS process for further evaluation. These investments are discussed below.

Investments within New Load Connections, Upgrades, Cancellations (DSP Section 3.11, D-SA-02) could in some cases be addressed by a flexible interconnection instead of a system expansion. To explore these opportunities, Hydro One will develop a flexible connection process and plans to leverage its DERMS platform to support these arrangements. Subsequently, flexible connection options will be offered to customers that are ready and able to participate, where they provide a cost-effective alternative to system reinforcement. Flexible interconnections must be assessed on a case-by-case basis and require certain criteria to be met, notably 1) the customer's desire to enter into a binding flexible agreement, and 2) the customer's ability to provide flexibility through either load curtailment or energy injection for a prescribed duration and frequency.

Investments within Reliability Improvements (DSP Section 3.11, D-SS-02) could conceptually be addressed through a non-wires solution such as energy storage. From a technical standpoint, energy storage could provide temporary service during outages by supplying load on an affected feeder. However, the feeders targeted under this investment serve many customers that result in substantial amounts of unsupplied energy during outage events. Providing an equivalent level of reliability improvement through energy storage would require a significant amount of storage capacity, making the non-wires alternative prohibitively expensive. In addition, energy storage is inherently limited by its available energy capacity and duration, whereas the proposed wires investments provide a longer-term solution with greater certainty of restoring and maintaining service reliability. Accordingly, in this case a NWS could not reasonably manage the system need to be addressed.

Investments under Energy Storage Solutions (DSP Section 3.11, D-SS-04) were removed from the NWS screening process because they are considered separately. These investments use energy storage as the solution to the identified system requirement. For these investments, Hydro One determined that there is no separate viable conventional wires alternative against which the energy storage solution requires comparison through the NWS assessment process. Accordingly, a comparative BCA is not required. The

project-specific assessment of technical feasibility and economic considerations supporting these energy storage investments is provided in DSP Section 3.11, D-SS-04.

Following Gate 1, investments under System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01), Demand System Modifications (DSP Section 3.11, D-SS-03), and Power Quality and Stray Voltage (DSP Section 3.11, D-SS-06) remain potentially suitable for NWS consideration and proceeded to Gate 2 for further screening.

3.0 GATE 2: BINARY SCREENING

Gate 2 applies three additional (binary) screening criteria to identify projects for which further NWS analysis is warranted, as follows:

1. **Projects ≥ $2M gross capital:** This requirement to screen out projects that are less than $2M is specified in the OEB's NWS Guidelines
2. **Timely Availability of Resources:** To be a viable alternative to a capital investment, sufficient time must be available to build and implement an NWS. Building up the necessary NWS resources requires persistent customer outreach efforts over an extended period. Time is also required to confirm the efficacy of the NWS. Given these constraints, Hydro One uses a period of two calendar years in its NWS process to provide sufficient time to acquire the NWS, to validate NWS efficacy through measurement and verification, and finally, to leave sufficient time such that the wires alternative can still be implemented without incurring inordinate risk if the NWS proves to be insufficient.
3. **Capacity to Reduce Peak Demand:** Although Hydro One considered multiple project types for NWS, only investments that address capacity needs were deemed suitable for further consideration. As noted in Section 2 of the OEB's NWS Guidelines, "...it is anticipated that many NWS may be designed to reduce peak demand". After considering potential use cases for NWS, Hydro One similarly concluded that capacity needs driven by peak demand should be the target for NWS within this application.

System Service investments that were screened out at this stage are Demand System Modifications (DSP Section 3.11, D-SS-03) and Power Quality and Stray Voltage investments (DSP Section 3.11, D-SS-06). The rationale for screening out these investments is given below.

Demand System Modifications investments are non-discretionary. They are used to facilitate customer connections or to correct an identified power quality issue. As a result of the need to respond quickly, these investments do not meet criteria #2 above. This program's expenditures consist of low-cost investments whose discrete value is below the $2M materiality threshold identified in the NWS Guideline, therefore, criteria #1 above is also not met.

Power Quality and Stray Voltage investments are also non-discretionary. They are required to maintain regulatory compliance or to address public safety issues. Similar to demand system modification investments, because of the need to respond quickly, these investments also do not meet criteria #2, nor is there technical certainty that NWS can address the underlying issue. For example, as detailed in DSP Section 3.11, D-SS-06, stray voltage can be caused by problems with the neutral and grounding systems, which is a type of sustainment issue for which NWS would not be effective. From an economic perspective, these are also low-cost investments, well below the $2M threshold for criteria #1.

System Upgrades Driven by Load Growth investments address distribution system capacity constraints arising where demand is expected to exceed planning limits of existing assets. These investments are generally driven by peak demand loading and therefore satisfy capacity-related criteria #3. Dispatchable DER, demand response and other NWS resources can potentially reduce or shift demand during peak periods and thereby defer the need for conventional capacity upgrades. These investments can also, depending on the timing of the identified need, provide sufficient time to plan for and acquire NWS resources and subsequently monitor and verify their effectiveness. However, load growth investments comprise a large number of individual load growth projects with

different investment values and need dates. Accordingly, Hydro One applied the remaining Gate 2 criteria (criteria #1 and #2) at the individual project level.

Load growth investments that did not satisfy criteria #1 and criteria #2 were screened out at Gate 2. Only load growth projects that satisfied all three Gate 2 criteria proceeded to the technical and economic viability assessment within Gate 3.

Taking the above criteria into consideration, 75 projects within System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01) were screened out at Gate 2, and 132 projects proceeded to the next gate.

4.0 GATE 3: VIABILITY SCREENING (TECHNICAL AND ECONOMIC)

Projects that pass Gate 2 binary screening are subject to viability screening, which estimates the technical and economic benefits of an NWS. The purpose of Gate 3 is to filter out projects that are clearly unsuitable before undertaking the more detailed Achievable Potential Study.

The considerations reflected in technical and economic viability screening are as follows:

4.1 TECHNICAL VIABILITY

Technical viability assesses whether an NWS can reliably meet the identified system need. This assessment considers the characteristics of the load driving the need, including the load shape, the frequency and duration of capacity constraints, and the magnitude of peak reduction required. An NWS may be technically viable where the capacity need occurs during discrete, predictable periods, such as a limited number of peak hours or days each year, and where the expected load reduction or load-shifting capability of the NWS is sufficient to address the constraint. Conversely, where load growth results in a sustained increase in baseload that exceeds equipment capacity limits, an NWS may not be suitable because intermittent or load-shaping measures are unsuitable to provide continuous relief. The technical viability assessment therefore determines whether the expected benefits of the NWS can match the timing, frequency, and magnitude of the system need.

Example of Technically Viable NWS:

A typical conventional wires solution to meet increasing peak loading needs is to upgrade a DS transformer to a larger size to meet the anticipated peak load on the transformer. For example, if a 6.25MVA transformer cannot continue to supply peak demand loading above its planning limit, an upgrade to 12.5MVA will mitigate the risk of failure. The goal of a NWS is to address the same system need by reducing peak demand loading such that the existing 6.25MVA transformer continues to operate within, or close to, its planning limit.

In this example, if the transformer in question had a planning limit of 6.25MVA, with peak demand loading of 6.75MVA, an NWS would be considered technically viable if it could reduce peak demand to within the transformer's planning limit based on the number of overload occurrences, and the duration and magnitude of each overload occurrence. This required reduction could be achieved by coordinating a combination of NWS resources as described in 3.6.5.1, including smart thermostat controls, EE programming, and C&I flexibility.

4.2 ECONOMIC VIABILITY

Economic viability is an initial assessment of the cost-effectiveness of an NWS. At this early screening stage, Hydro One uses an estimate of anticipated NWS costs to inform a decision on whether the NWS warrants further consideration.

For the purposes of economic screening, Hydro One assesses multiple combinations of NWS implementation periods and capital investment deferral durations to determine whether an NWS can provide a cost-effective alternative to the conventional wires solution. Where the NWS does not demonstrate cost-effectiveness under any of the evaluated scenarios, it is screened out and the project proceeds as a conventional wires investment. This approach avoids the time and expense of a detailed NWS study if initial estimates suggest the NWS is unlikely to provide a robust cost-effective deferral.

The above methodology mitigates key risks inherent to NWS, such as the failure to achieve expected deferral benefits, and the possibility that implementation costs exceed initial projections. Given the relative nascency of NWS and the associated uncertainties, applying economic screening is prudent and ensures that only solutions with a reasonable expectation of delivering cost-effective outcomes will proceed to the Achievable Potential Study stage.

NWS investments that demonstrate a reasonable potential to be both technically and economically viable will proceed to the detailed “Achievable Potential Study” in Gate 4. Gate 3 is intended to be an inclusive preliminary screening step. Hydro One applies the screening criteria broadly so that potential NWS opportunities are not screened out where more detailed analysis could demonstrate a viable solution. Accordingly, where uncertainty remains regarding the achievable level of demand reduction, available resource potential, customer participation or other project-specific factors, the candidate is retained for further assessment through Gate 4 - Achievable Potential Study.

Based on the above rationale and screening criteria, 100 projects were determined to be unsuitable for an NWS and were screened out. One project did not advance to Gate 4 because the criteria for technical and economic viability were sufficiently satisfied using a Mobile Battery Energy Storage System (MBESS), which is actively being used to defer an existing system need. Additional NWS measures showed limited availability for this project, and as a result, a Gate 4 assessment was not warranted since there was little incremental value anticipated beyond the identified MBESS solution. The impacted project, SS-01.102 “Kashabowie HVDS”, was planned for in-servicing in 2028. MBESS was identified as a suitable option for this location. As a result, “Kashabowie HVDS” has been successfully deferred to 2031. The remaining 31 projects advanced to Gate 4 of the NWS assessment process.

5.0 GATE 4: ACHIEVABLE POTENTIAL STUDY

Projects that proceed through Gate 3 are subject to a detailed Achievable Potential Study to determine the amount and type of NWS resources that could reasonably be acquired

within the geographic area affected by the identified system need. As Hydro One is still developing the internal capabilities to conduct detailed non-wires assessments, the company has retained a third party to perform achievable potential studies for this DSP.

The achievable potential studies begin by quantifying the following for the area under study:

- Known energy consumption by sector (residential / commercial / industrial)
- Segmentation within each sector (for example, types of residential homes such as detached / attached / apartments)
- End-uses within each segment (clothes dryers, cooking, AC)
- Unit energy consumption (amount of energy used by each end-use, per unit)
- Saturation rate of each end-use (the extent to which an end-use is present in a region or segment, for example if every house has a refrigerator the saturation rate would be 100%)
- Fuel share (% of energy end-use that is supplied by gas vs electric for end-uses such as cooking or water heaters)

Using the above, a calculation of “consumption” is performed per end-use. This quantification can be viewed at the regional or local level, based on the number of units and end-uses within an area. Further, as load growth is forecast within a region based on general trends or approved developments, anticipated changes to end-use consumption can be estimated.

With energy consumption forecasts, it also becomes possible to quantify the potential success of an NWS measure based on the targeted end-use. Third-party analysis, using proprietary tools, predicts the likelihood of a particular measure succeeding based on the incentive offered and the end-use being targeted. By quantifying the benefits from various applicable measures, the viability of an NWS in place of a traditional solution becomes clearer. With known unit costs of each measure to be applied, it also becomes possible to populate a BCA for projects that are deemed technically viable.

The resulting studies provide an estimate of the achievable program potential available to address the identified system need and the associated program costs. The studies for each project are presented in Attachments 5.01 to 5.17 – NWS Project Technical Analyses. The Methodology supporting these studies can be found in Attachment 2 – NWS Technical Analysis Methodology Document.

Hydro One reviews the achievable potential identified in the study together with the load forecast, applicable planning limit, magnitude and timing of the forecast capacity exceedance, and the timing and quantity of NWS resources required to maintain loading within an acceptable range. Hydro One then determines whether a technically viable NWS portfolio can reasonably be implemented to address the identified system need. The results of Hydro One's assessment of technical viability are presented in Attachments 3.01 to 3.19 – NWS Project Overview & Financial Summary.

Of the 31 projects that proceeded to Gate 4, Hydro One completed or initiated detailed Achievable Potential Studies to determine whether sufficient NWS resources could reasonably be acquired to address the identified capacity requirements. 7 projects were shown to be not technically viable.

For one of the 7 projects identified as not viable, "Wingham DS Load Growth", the costs had been removed from the capital plan in anticipation of an NWS. Since the Achievable Potential Study determined that sufficient NWS potential was not available within the affected area to address the forecast system need, these costs will need to be reintroduced as a capital load growth investment under Load Growth Investments (DSP Section 3.11, D-SS-01). Since a NWS was not technically viable for this project, it also did not proceed to the BCA in Gate 5. The underlying system need remains and is expected to be addressed through the applicable conventional capacity investment, estimated at a net cost of $7.0M.

For 8 projects, the Achievable Potential Studies are currently in progress and have not yet been completed. Accordingly, Hydro One has not yet made a final determination regarding technical viability for these projects, and they have not yet proceeded to Gate 5.

For the remaining 16 projects, Hydro One concluded, based on the Achievable Potential Studies and Hydro One's technical assessment, that sufficient NWS capability could reasonably be implemented to address the identified capacity needs. These projects passed Gate 4 and proceeded to the detailed BCA in Gate 5.

6.0 GATE 5: BENEFIT COST ANALYSIS

Should an Achievable Potential Study confirm the technical viability of an NWS, Hydro One will move forward with a Benefit Cost Analysis to determine whether the NWS is economic relative to the conventional wires alternative.

Consistent with the BCA Framework, Hydro One considers the deferral value (calculated as the improvement in NPV resulting from the deferral of planned capital expenditures), and compares this against forecast annual NWS expenditures to reduce peak loading. The BCA includes programmatic costs for activities such as targeted smart thermostat and EE programs, as well as flexibility procurements from commercial and industrial customers. The expenditures captured within these different non-wires programs include both incentive costs (direct payments to customers) as well as non-incentive costs covering other program activities such as device fees.

The results of the BCA performed in this gate determined that 14 projects had a cost-benefit ratio of greater than 1 based on the results of Distribution System Test and were deemed suitable for an NWS. For the remaining 2 projects, the Energy System Test was subsequently applied; both projects achieved a benefit cost ratio greater than 1 and were also deemed suitable for an NWS.

The application of the NWS assessment process resulted in a final portfolio of 16 NWS projects identified in Load Growth Investments (DSP Section 3.11, D-SS-01), representing

approximately $103M of deferred capital expenditures beyond the 2028-2032 period. In addition to these 16 projects, and as mentioned in Gate 3 above, there is an ongoing application of an MBESS as an NWS to defer the D-SS-01.102 investment “Kashabowie HVDS”. This project was planned for in-servicing in 2028, but this planned in-service has subsequently been deferred to 2031.

As these projects are implemented, the portfolio may be adjusted in response to changes in underlying system needs and NWS achievability as described in DSP Section 3.6, Subsection 3.6.5.3, with resulting cost variances addressed through the proposed symmetrical variance account described in Exhibit G-01-03, Section 9.4.

ATTACHMENTS

Table 1 below provides a list of attachments for each project.

Table 1 - List of Attachments for Technical Analysis and BCA for NWS Projects

Attachment ID	Attachment Description
Attachment 2 - NWS Technical Analysis Methodology Document	This attachment details the general methodology and study approach made by Posterity Group for each of the achievable potential studies performed in Attachments 5.01 to 5.17.
Attachments 3.01 to 3.19 - NWS Summaries	These attachments summarize Hydro One’s technical and economic analysis and conclusions for each project studied in Gate 4 that will move to Gate 5 (including Wingham DS).
Attachments 4.01 to 4.04 - NWS BCA Supporting Spreadsheets	These attachments summarize the BCAs for projects and programs that proceeded to Gate 5. For the 16 projects that will be executed as NWS, all BCA analyses are contained within a single spreadsheet.
Attachments 5.01 to 5.17 - NWS Technical Analysis	These attachments summarize the technical viability results from Posterity Group for each study that proceeded to a BCA.

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NWS Analysis Methodology

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: NWS Analysis Methodology
Submitted to: Hydro One Networks Inc.

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1 Introduction

This document provides high level summary of data inputs and methods used to develop the Full System Model (FSM) and the process used to conduct non-wires solutions (NWS) analyses for Hydro One Networks Inc (HONI) by Posterity Group Consulting Inc. (PG).

2 Approach – Full System Model

2.1 About the Model

The FSM is the foundational model used to scale down to selective regions or sub-regions to investigate NWS opportunities within HONI's service territory. Hydro One provides key customer, load, and forecast inputs used in the Full System Model (FSM), which are incorporated into the forecasting model to estimate the potential demand reductions and program costs associated with various NWS measures. The model uses customer, end-use, and energy consumption characteristics to quantify the expected benefits and costs of NWS programs.

2.2 Base Year and Reference Case Consumption and Peak Demand

A base-year energy consumption model was developed by assigning customers to sectors and end uses using industry data sources and Hydro One customer information. The model was then calibrated to Hydro One actual consumption data and adjusted to align with Hydro One's forecasted customer, energy, and demand growth.

Peak demand was derived using end-use load profiles and calibrated to Hydro One's historical peak demand data at a regional level. The calibrated relationships between energy consumption and peak demand were then applied throughout the forecast period to estimate future peak demand growth.

2.3 Measure Characterization

PG developed two types of measures characterized by consumption of potential adopters, potential savings, incremental cost, affected end-use(s), participation, and potential interactions with other measures.

1. *Energy Efficiency (EE):* energy efficiency incentive programs.
2. *Demand Response (DR)*: direct load control programs, targeted notifications, and resources on the customer side (e.g., smart thermostat control, commercial/industrial flexibility).

2.3.1 Energy Efficiency Measures

All EE measures are derived from existing IESO programs and assumptions. Energy efficiency (EE) measures are designed to reduce electricity consumption and peak demand by improving the efficiency of equipment and end uses. The analysis considers both existing IESO-funded programs and a scenario where Hydro One provides incentive top-ups to increase customer participation. Measure savings, costs, and adoption are estimated using established program assumptions, technical reference data, end-use studies, and historical program experience. Participation levels are forecast using Posterity's adoption model, which considers factors such as measure economics, customer acceptance, and market diffusion.

2.3.2 Demand Response Measures

Demand response (DR) measures are designed to reduce electricity demand during peak periods by modifying customer electricity usage patterns rather than reducing overall energy consumption. The analysis includes residential programs, such as smart thermostats, and commercial and industrial flexibility programs. Measure participation and performance assumptions are based on Ontario DER potential studies, Hydro One program experience, historical participation rates, incentive levels, and program costs. The resulting estimates are used to quantify the peak demand reductions and associated program costs that could be achieved through targeted demand response initiatives.

3 Results

The following outputs are provided for each NWS analysis:

- Annual gross load forecast
- Annual peak reduction by NWS measure type (EE & DR)
- Annual net load forecast (including reductions from NWS)
- Annual program costs associated with NWS reductions
- 10-year forecast of energy and peak demand savings

3.1 NWS Peak Reduction and Spending

Results for NWS peak reduction and spending for the EE measures can be attributed both to HONI and the IESO and are therefore split between the two. HONI assumes that a targeted NWS would top up existing IESO incentives to achieve higher measure uptake. Exhibit 1 describes the different results as shown in each NWS report.

Exhibit 1 - NWS Peak Reduction and Spending

Result	Description
Cumulative Peak Reduction from IESO-funded EE	Total savings associated with EE measures when HONI does not top up the incentive provided by the IESO.
Cumulative Peak Reduction from HONI-funded NWS	Incremental savings associated with the incentive top-up to EE measures provided by HONI, plus the total savings from DR measures.
Annual NWS Program Incentive Costs	Incremental incentive costs from the incentive top-up to EE measures provided by HONI plus the total incentive costs from DR measures.
Annual NWS Program Non-Incentive Costs	One quarter[1] of the incremental non-incentive costs associated with new participation in EE measures caused by the incentive top-up provided by HONI plus the total non-incentive costs from DR measures.

3.2 NWS Energy and Peak Demand Savings

The NWS reports show 10 years of projected cumulative energy and peak demand savings associated with HONI EE and DR implementation for the purpose of populating the EST portion of the BCA.

[1] Three quarters of the incremental non-incentive costs are attributed to the IESO as administrator of the program.

NWS Summary – Birr DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Birr DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Ilderton area, located within Hydro One's South zone, is forecast to increase loading on the existing 27.6kV:8.32kV, 5MVA station at Birr DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 5.36MVA. The summer peak load is forecast to increase by 0.99MVA by 2032, reaching 6.35MVA, which exceeds the station's 6.25MVA planning limit by 0.10MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Birr DS from 5MVA to 7.5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Birr DS is forecast to exceed its planning limit by 0.10**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.32**MW** by 2032, equivalent to 0.35**MVA** of load relief assuming a power factor of 0.92.

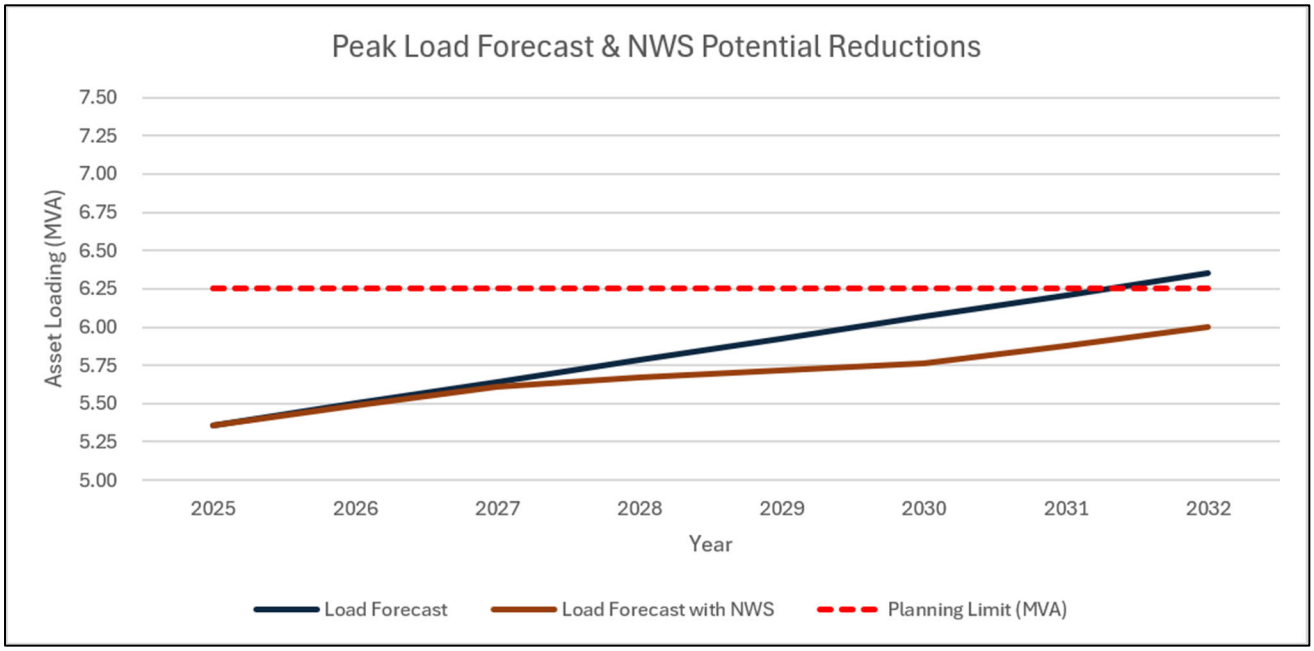
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Birr DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Birr DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.21**
NPV Total Benefit of NWS ($M):	**0.83**
NPV Net Benefit ($M):	**0.62**
Benefit: Cost Ratio	**3.99**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.25**
NPV Total Benefit if NWS ($M):	**1.27**
NPV Net Benefit ($M):	**1.02**
Benefit: Cost Ratio	**5.15**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Birr DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Carleton Place Francis DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Carleton Place Francis DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the town of Carleton Place, located within Hydro One's East zone, is forecast to increase loading on the existing 44kV:4.16kV, 5MVA station at Carleton Place Francis DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 5.70MVA. The summer peak load is forecast to increase by 0.57MVA by 2032, reaching 6.27MVA, which is approximately equal to the station's 6.25MVA planning limit.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Carleton Place Francis DS from 5MVA to 10MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Carleton Place Francis DS is forecast to reach its planning limit within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.34**MW** by 2032, equivalent to 0.37**MVA** of load relief assuming a power factor of 0.92.

The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Carleton Place Francis DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

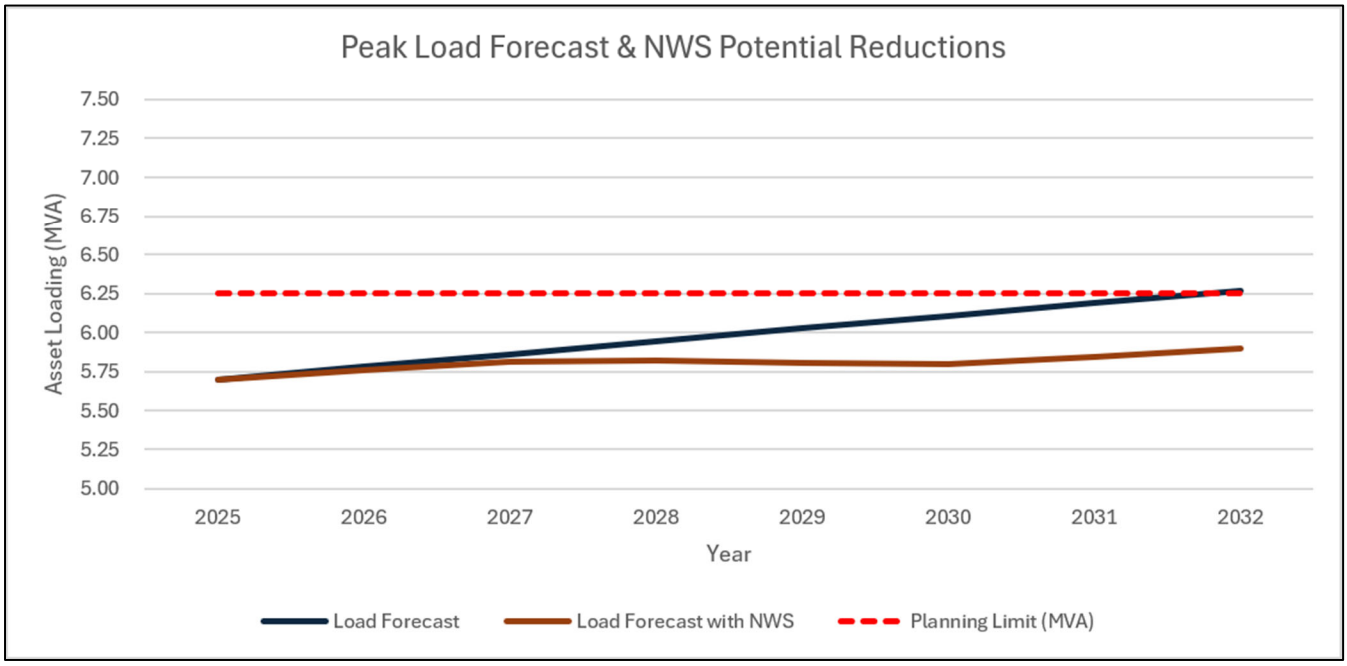
1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response

(DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Carleton Place Francis DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.37**
NPV Total Benefit of NWS ($M):	**0.81**
NPV Net Benefit ($M):	**0.44**
Benefit: Cost Ratio	**2.19**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.44**
NPV Total Benefit if NWS ($M):	**1.38**
NPV Net Benefit ($M):	**0.94**
Benefit: Cost Ratio	**3.13**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Carleton Place Francis DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Chesterville TS M1

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Chesterville TS M1 wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Winchester area, located within Hydro One's East zone, is forecast to increase loading on the existing 44kV, M1 feeder at Chesterville TS beyond its 30MVA planning limit. The asset is summer constrained with a current summer peak demand load of 28.0MVA. The summer peak load is forecast to increase by 4.0MVA by 2032, reaching 32.0MVA, which exceeds the feeder's 30MVA planning limit by 2.0MVA.

Alternatives Considered

1. Reference Scenario (Wires): Extend the Chesterville TS M4 feeder to offload the M1, thereby maintaining loading within the feeder capacity limit of 30MVA.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the feeder.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Chesterville TS M1 is forecast to exceed its planning limit by 2.00**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 1.85**MW** by 2032, equivalent to 2.01**MVA** of load relief assuming a power factor of 0.92.

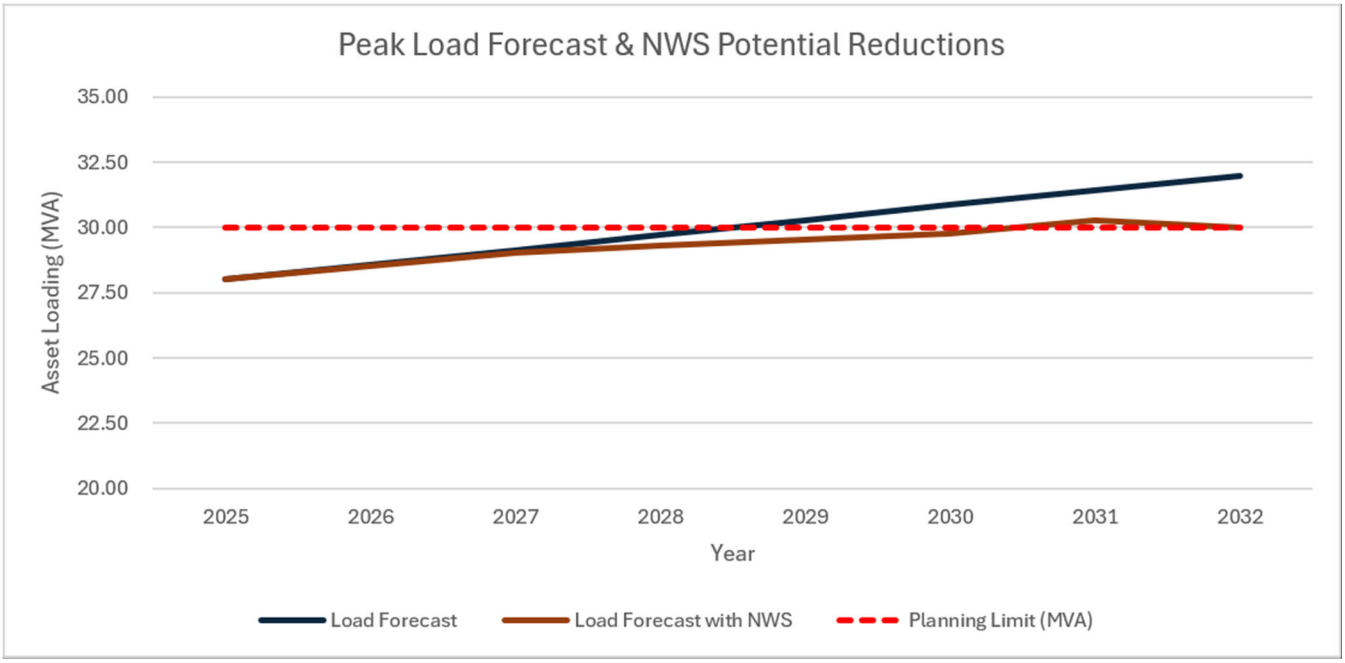
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Chesterville TS M1 Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Chesterville TS M1. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.97**
NPV Total Benefit of NWS ($M):	**1.93**
NPV Net Benefit ($M):	**0.96**
Benefit: Cost Ratio	**1.99**

Table 2: EST Results

NPV Cost of NWS ($M):	**1.11**
NPV Total Benefit if NWS ($M):	**4.35**
NPV Net Benefit ($M):	**3.23**
Benefit: Cost Ratio	**3.91**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Chesterville TS M1. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Dixons Corners DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Dixons Corners DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Winchester area, located within Hydro One's East zone, is forecast to increase loading on the existing 44kV:8.32kV, 5MVA station at Dixons Corners DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 5.33MVA. The summer peak load is forecast to increase by 1.57MVA by 2032, reaching 6.90MVA, which exceeds the station's 6.25MVA planning limit by 0.65MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Dixons Corners DS from 5MVA to 10MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Dixons Corners DS is forecast to exceed its planning limit by 0.65**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.35**MW** by 2032, equivalent to 0.38**MVA** of load relief assuming a power factor of 0.92.

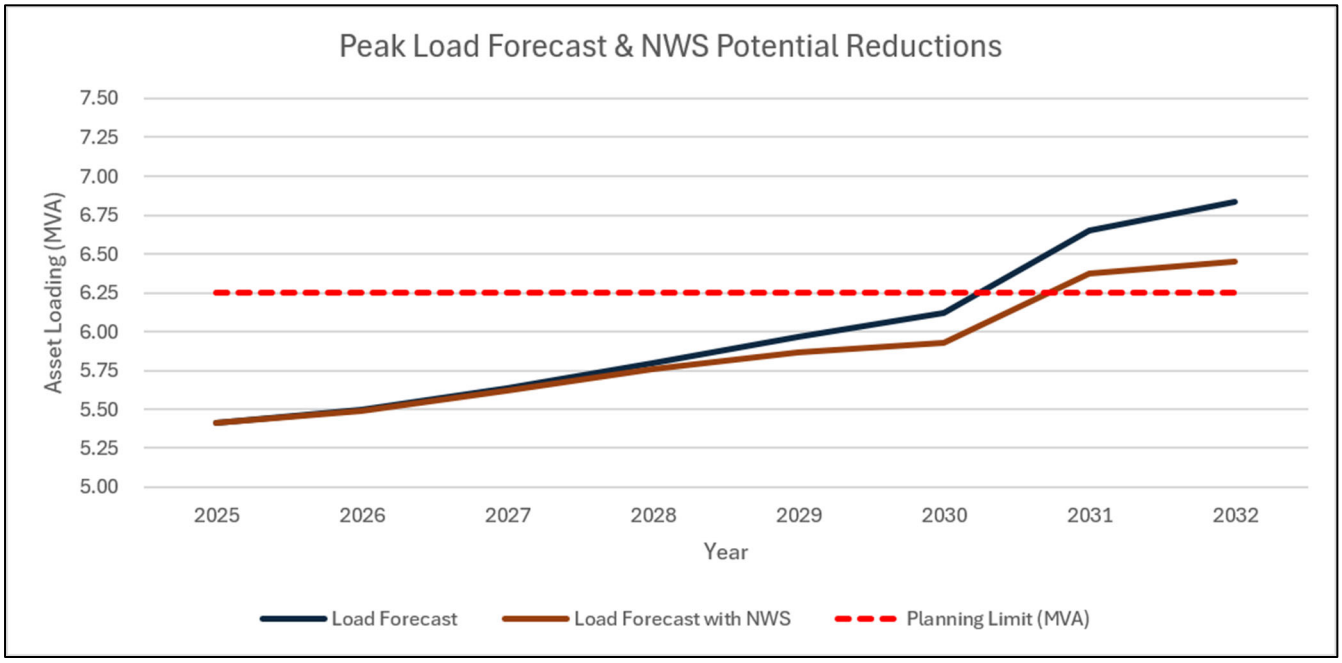
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Dixons Corners DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Dixons Corners DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.23**
NPV Total Benefit of NWS ($M):	**0.63**
NPV Net Benefit ($M):	**0.40**
Benefit: Cost Ratio	**2.71**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.24**
NPV Total Benefit if NWS ($M):	**1.10**
NPV Net Benefit ($M):	**0.86**
Benefit: Cost Ratio	**4.52**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Dixons Corners DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Fergusonvale DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Fergusonvale DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in Springwater township, located within Hydro One's Central zone, is forecast to increase loading on the existing 44kV:8.32kV, 5MVA station at Fergusonvale DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 6.00MVA. The summer peak load is forecast to increase by 0.98MVA by 2032, reaching 6.98MVA, which exceeds the station's 6.25MVA planning limit by 0.73MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Fergusonvale DS from 5MVA to 10MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Fergusonvale DS is forecast to exceed its planning limit by 0.73**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.37**MW** by 2032, equivalent to 0.40**MVA** of load relief assuming a power factor of 0.92.

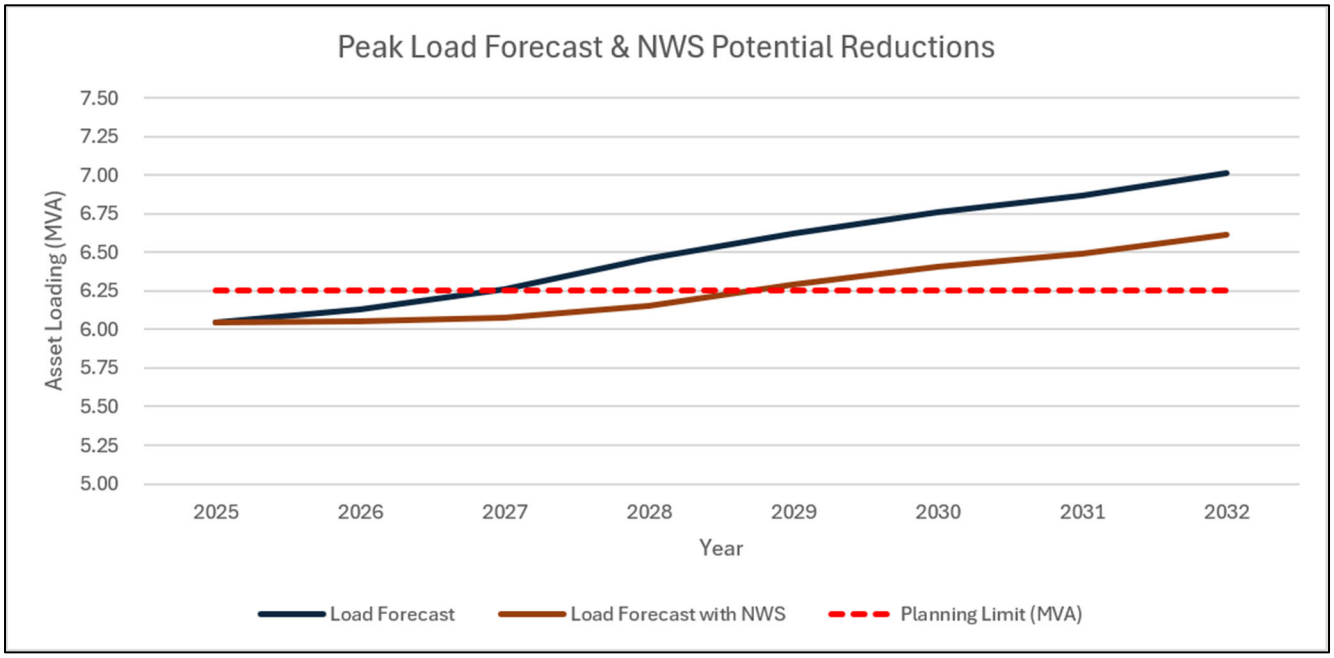
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Fergusonvale DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Fergusonvale DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.16**
NPV Total Benefit of NWS ($M):	**0.64**
NPV Net Benefit ($M):	**0.47**
Benefit: Cost Ratio	**3.90**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.19**
NPV Total Benefit if NWS ($M):	**1.27**
NPV Net Benefit ($M):	**1.09**
Benefit: Cost Ratio	**6.77**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Fergusonvale DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Horsey Bay DS T2

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Horsey Bay DS T2 wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Kingston area, located within Hydro One's Central zone, is forecast to increase loading on the existing 44kV:8.32kV, 5MVA T2 station at Horsey Bay DS T2 beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 6.60MVA. The summer peak load is forecast to increase by 0.80MVA by 2032, reaching 7.40MVA, which exceeds the station's 6.25MVA planning limit by 1.15MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Horsey Bay DS T2 from 5MVA T2 to 10MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Horsey Bay DS T2 is forecast to exceed its planning limit by 1.15**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.45**MW** by 2032, equivalent to 0.49**MVA** of load relief assuming a power factor of 0.92.

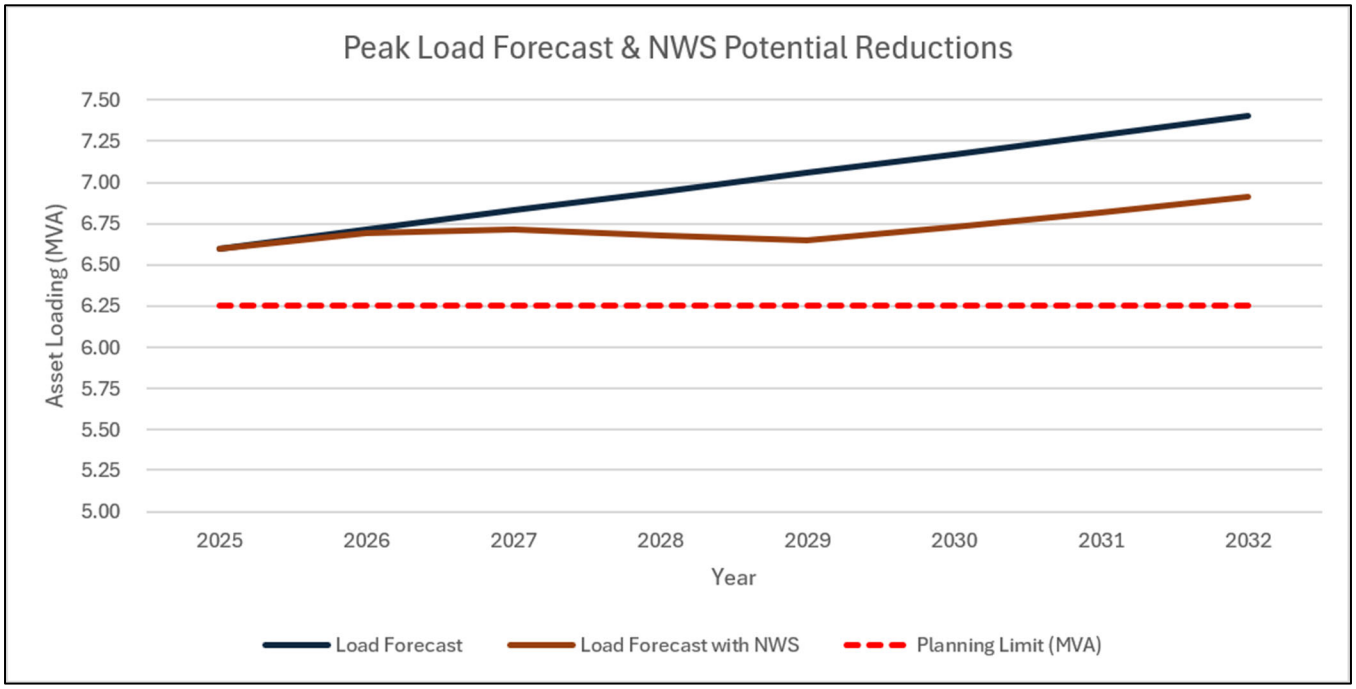
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Horsey Bay DS T2 Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio less than 1 under the DST and greater than 1 under the EST. Since the DST benefit-cost ratio is slightly less than 1, but the EST benefit-cost ratio is well above 1, Hydro One sees this as an indication that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Horsey Bay DS T2. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.32**
NPV Total Benefit of NWS ($M):	**0.32**
NPV Net Benefit ($M):	**0.00**
Benefit: Cost Ratio	**0.99**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.36**
NPV Total Benefit if NWS ($M):	**1.06**
NPV Net Benefit ($M):	**0.71**
Benefit: Cost Ratio	**2.98**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Horsey Bay DS T2. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Kashabowie HVDS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Kashabowie HVDS wires investment, summarizing the NWS considerations, technical viability, economic viability, and final results.

Need

Load growth in the area west of Shabaqua, near Kashabowie, located within Hydro One's Northern zone, has experienced increased loading on the 7.2kV single-phase line, from Shabaqua DS F1, that supplies it. The length of the existing supply creates low voltage issues during times of peak demand, on weekends throughout the summer months.

Alternatives Considered

1. Reference Scenario (Wires): Build a new dual-bank 115kV:12.5kV 7.5MVA High Voltage Distribution Station (HVDS) with two feeder positions to support load growth in the Kashabowie area.
2. NWS: Use a Mobile Battery Energy Storage System (MBESS) to manage peak demand loading, while recharging the MBESS at times when peak loading subsides.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable through 2031. Hydro One's assessment is based on operating experience with the existing MBESS installation and supporting system studies, which demonstrate that the MBESS can effectively mitigate peak loading to improve voltage performance in the Kashabowie area. Other NWS options, including demand response, energy efficiency, and customer flexibility measures, were not considered technically viable due to the customer composition in the area. As a result, the assessment focused on the MBESS as the only viable NWS alternative. The MBESS is expected to remain technically viable through to 2031. Beyond 2031, system needs driven by forecast load growth are anticipated to exceed MBESS capabilities, thereby making it no longer viable. Specifically, forecast load growth and system constraints will prevent sufficient off-peak charging to support peak demand requirements and create challenges associated with feeder protection limitations driven by declining fault-to-load ratios. As a result, the MBESS is no longer considered technically viable beyond 2031.

BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the NWS would defer the wires investment until 2031, consistent with the period over which the MBESS is expected to remain technically viable.
The assumed deferral period was used to calculate the Distribution Service Test (DST). Since the NWS solution is only being used for peak demand reduction at times that are generally not coincident with system peak, and since the economic test passes the DST, Energy System Test (EST) benefits were not calculated.

As summarized in **Table 1: DST Results**, the NWS achieved a benefit-cost ratio greater than 1, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing NWS measures. Accordingly, Hydro One concludes that the NWS is **economically viable** and represents a cost-effective approach to addressing the identified system need at Shabaqua DS F1. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – Kashabowie HVDS BCA. This Excel-based model forms the basis of the economic assessment and supports the DST results summarized in the table below.

Table 1: DST Results

NPV Cost of NWS ($M):	**1.21**
NPV Total Benefit of NWS ($M):	**2.08**
NPV Net Benefit ($M):	**0.87**
Benefit: Cost Ratio	**1.71**

Risk Mitigation

Ongoing monitoring of customer load growth, peak demand levels, and MBESS performance will be used to verify that the MBESS remains capable of meeting system needs and continues to be technically viable through 2031. Hydro One anticipates that the pacing of the current wires solution, project SS-01.102 “Kashabowie HVDS” is appropriate to address system needs, while maintaining technical viability, however additional deferrals beyond what is contemplated in D-SS-01.102 are not prudent as the NWS is expected to become unviable beyond 2031.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Hydro One believes the current pacing of the wires investment best reflects a balance of economic benefits resulting from investment

deferral, while also managing associated technical risks by using NWS to address system needs.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the system need at Shabaqua DS until 2031. Using NWS to improve system voltage is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Kingsville Pulford DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Kingsville Pulford DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Kingsville area, located within Hydro One's South zone, is forecast to increase loading on the existing 27.6kV:8.32kV, 5MVA station at Kingsville Pulford DS beyond its 5.75MVA planning limit. The asset is summer constrained with a current summer peak demand load of 4.80MVA. The summer peak load is forecast to increase by 1.02MVA by 2032, reaching 5.82MVA, which exceeds the station's 5.75MVA planning limit by 0.07MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Kingsville Pulford DS from 5MVA to 7.5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Kingsville Pulford DS is forecast to exceed its planning limit by 0.07**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.28**MW** by 2032, equivalent to 0.31**MVA** of load relief assuming a power factor of 0.92.

The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Kingsville Pulford DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

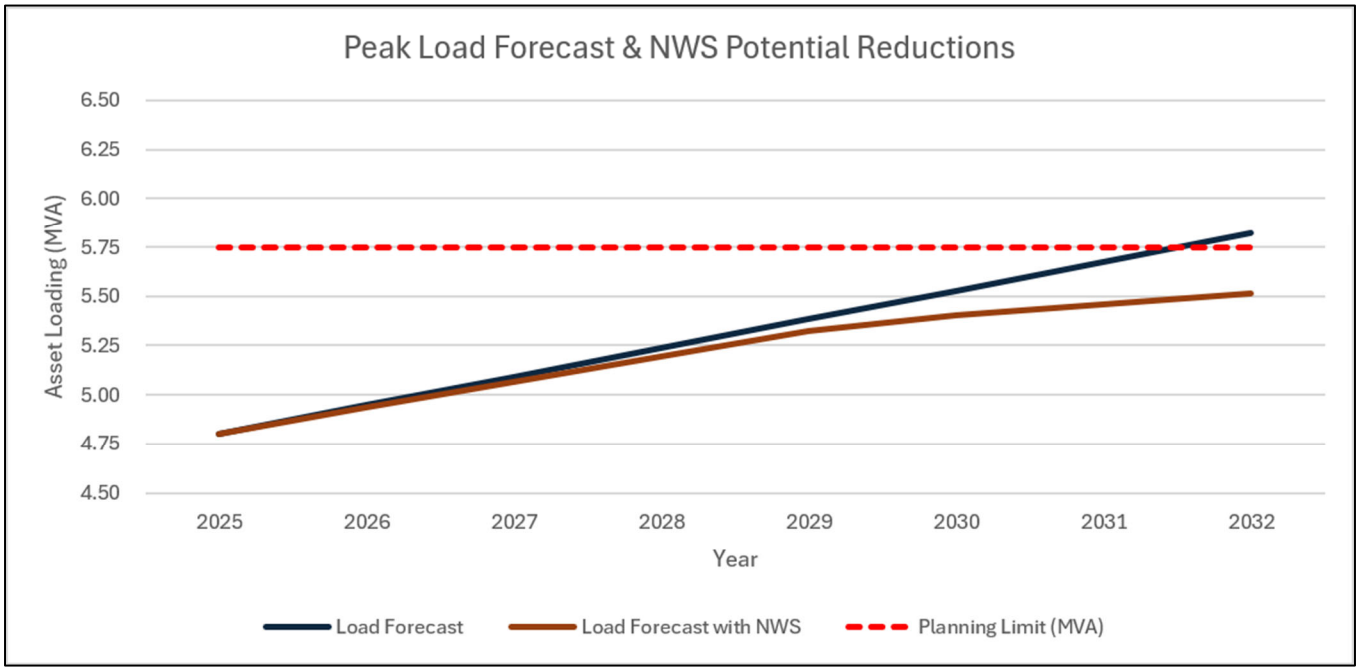
1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response

(DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Kingsville Pulford DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.29**
NPV Total Benefit of NWS ($M):	**0.76**
NPV Net Benefit ($M):	**0.48**
Benefit: Cost Ratio	**2.66**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.30**
NPV Total Benefit if NWS ($M):	**1.10**
NPV Net Benefit ($M):	**0.80**
Benefit: Cost Ratio	**3.64**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Kingsville Pulford DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Lanark DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Lanark DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Lanark area, located within Hydro One's East zone, is forecast to increase loading on the existing 44kV:8.32kV, 5MVA station at Lanark DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 5.00MVA. The summer peak load is forecast to increase by 1.80MVA by 2032, reaching 6.80MVA, which exceeds the station's 6.25MVA planning limit by 0.55MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Lanark DS from 5MVA to 10MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Lanark DS is forecast to exceed its planning limit by 0.55**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.52**MW** by 2032, equivalent to 0.56**MVA** of load relief assuming a power factor of 0.92.

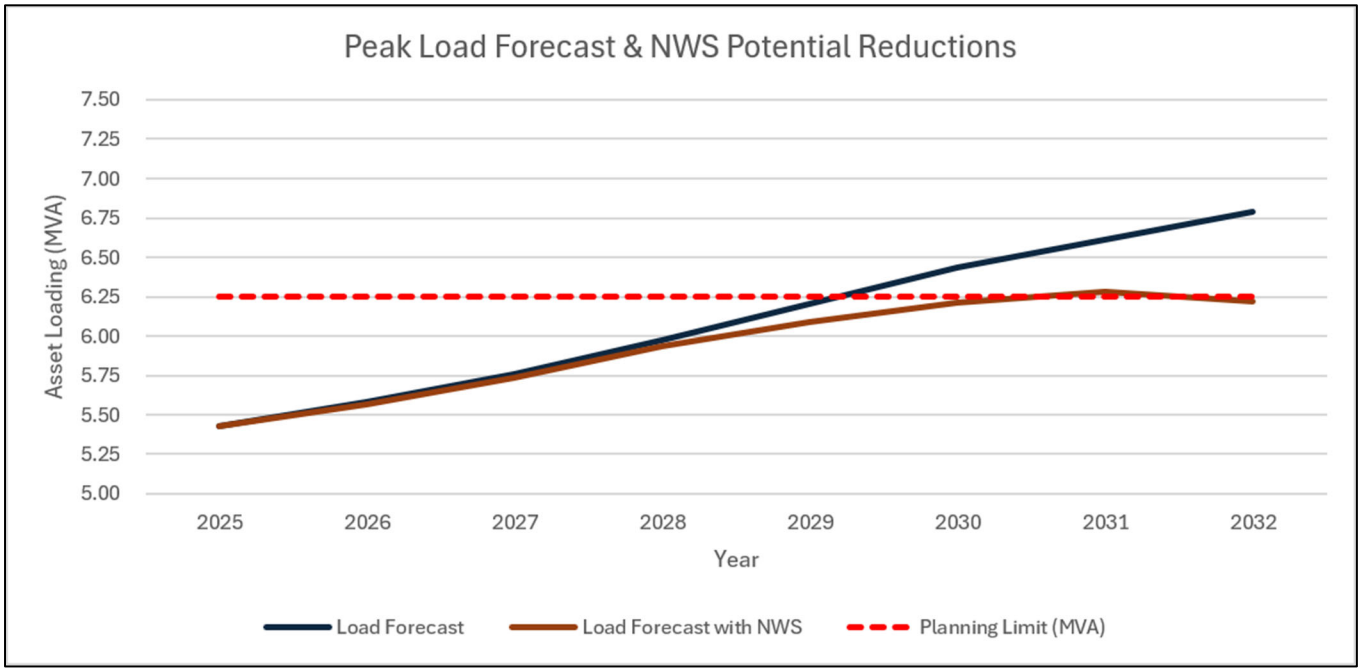
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Lanark DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Lanark DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.42**
NPV Total Benefit of NWS ($M):	**1.11**
NPV Net Benefit ($M):	**0.69**
Benefit: Cost Ratio	**2.66**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.45**
NPV Total Benefit if NWS ($M):	**1.96**
NPV Net Benefit ($M):	**1.51**
Benefit: Cost Ratio	**4.39**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Lanark DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – New "Bragg" DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to a new "Bragg" DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Clarington area, located within Hydro One's Central zone, is forecast to increase loading on the existing 44kV:27.6kV, station at Curve Inn DS T2 beyond its 13.80MVA planning limit. The asset is summer constrained with a current summer peak demand load of 14.00MVA. The summer peak load is forecast to increase by 1.70MVA by 2032, reaching 15.70MVA, which exceeds the station's 13.80MVA planning limit by 1.90MVA.

Alternatives Considered

1. Reference Scenario (Wires): Construct a new 10MVA "Bragg" DS to relieve loading on Curve Inn DS T2, and to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Curve Inn DS T2 is forecast to exceed its planning limit by 1.90**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 1.28**MW** by 2032, equivalent to 1.39**MVA** of load relief assuming a power factor of 0.92.

The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Curve Inn DS T2 DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

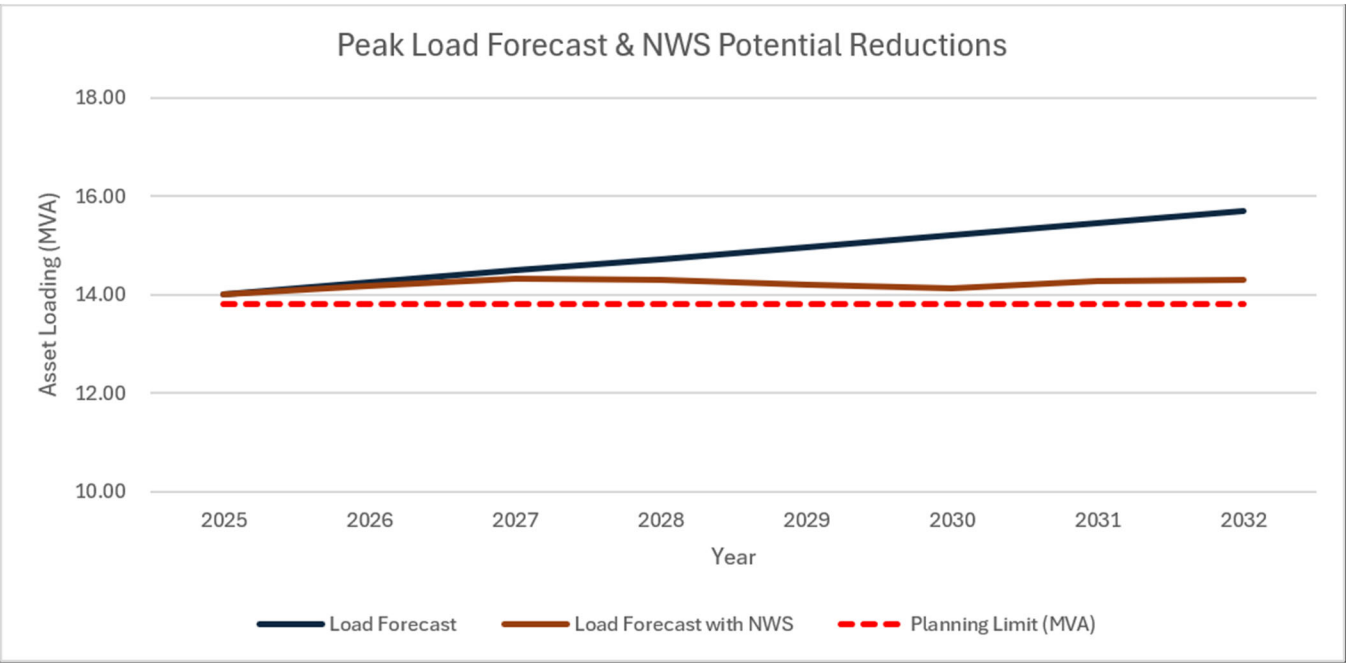
1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response

(DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio **less than 1** under the DST and **greater than 1** under the EST. With the DST benefit-cost ratio slightly less than 1, and an EST benefit-cost ratio greater than 1, Hydro One sees sufficient value in pursuing NWS to defer the traditional wires investment. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Curve Inn DS T2. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**1.26**
NPV Total Benefit of NWS ($M):	**1.08**
NPV Net Benefit ($M):	**-0.18**
Benefit: Cost Ratio	**0.86**

Table 2: EST Results

NPV Cost of NWS ($M):	**1.41**
NPV Total Benefit if NWS ($M):	**2.68**
NPV Net Benefit ($M):	**1.27**
Benefit: Cost Ratio	**1.90**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Curve Inn DS T2. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary - Non-Targeted Demand Response and Local Energy Efficiency Programs

1. Introduction

Hydro One assessed the economic viability of non-targeted demand response (DR) and Local Energy Efficiency (EE) programs as Non-Wires Solutions (NWS) that function as programmatic investments that provide geographically dispersed peak reductions across the distribution system. The assessment focused on areas outside the 16 locations where targeted Demand Response and Local Energy Efficiency were identified as a cost-effective means of deferring distribution capital investments, see D-SS-01 for the identified 16 investments.

These programs are intended to provide broad distribution system capacity benefits rather than defer specific station, feeder, or transformer investments within the 2028-2032 rate period. The assessment evaluates whether the benefits of these programs exceed their incremental costs.

Consistent with the Ontario Energy Board's Benefit-Cost Analysis Framework for Addressing Electricity System Needs, Hydro One applied the Distribution Service Test (DST) and Energy System Test (EST). The DST compares the present value of distribution benefits to program costs, while the EST evaluates broader electricity system benefits. A benefit-cost ratio greater than 1.0 indicates that program benefits exceed costs.

Hydro One applied the Marginal Capacity Value method to quantify distribution capacity benefits of these programs because it provides an appropriate means of valuing programmatic peak demand reductions across the service territory, rather than those associated with the deferral a single identifiable wires investment.

2. Need

Hydro One's distribution system is expected to experience continued load growth over the planning period, creating an ongoing need to manage loading relative to asset planning limits to maintain system reliability and power quality. As a result, Hydro One has identified a need to reduce peak demand across the distribution system to help mitigate load growth and reduce the need for future distribution capacity investments. The demand response and Local Energy Efficiency programs provide broad, system-wide peak demand reductions that can defer future distribution upgrades that have not yet been specifically identified through the planning process. Establishing DR and EE capabilities in advance provides a resource that can be mobilized to address urgent or emerging capacity needs and support consideration of non-wires alternatives to traditional distribution investments.

3. Alternatives Considered

Alternative 1: Business-as-Usual Distribution Capacity Investments (Reference Scenario)

Under the reference scenario, Hydro One would continue to meet distribution capacity requirements arising from load growth through business-as-usual distribution investments. As loading on feeders and stations increases and capacity requirements emerge, future distribution capacity needs would be addressed through traditional wires investments where there is insufficient time to acquire and scale NWS resources after a system need is identified. The timing and scope of these investments would continue to be determined through the established investment planning process.

Alternative 2: Implement Non-Targeted Demand Response and Local Energy Efficiency Programs

Under this alternative, Hydro One would implement non-targeted demand response and Local EE programs to reduce peak demand across the distribution system and help mitigate future load growth. These programs would also establish a flexible demand-side resource that can be deployed to address emerging capacity needs and support future non-wires solutions as distribution system constraints are identified.

4. Hydro One Assessment of Technical Viability

Hydro One considers both the demand response and Local Energy Efficiency programs to be technically viable. This assessment is based on Hydro One's experience implementing demand response initiatives during the 2023-2027 rate period and the use of established energy efficiency programs offered by Independent Electricity System Operator (IESO).

The demand response program is supported by Hydro One's experience with residential demand response initiatives described in Section 3.6.5.1, NWS Experience. These initiatives have provided practical experience regarding resource performance, customer participation, and dispatchability.

The Local EE program will build on existing IESO energy efficiency programs through the use of targeted incentive adders. At the outset, Hydro One expects this to include a Retrofit Incentive Adder program for commercial and industrial customers. This approach leverages established energy efficiency offerings and delivery mechanisms. Additional program details are provided in E-03-04, Section 5.1, Flexibility Through Local Energy Efficiency.

5. Rationale for Using Marginal Capacity Value

Hydro One applied the Marginal Capacity Value method to calculate the benefits of the demand response and Local EE programs. This is appropriate because the non-targeted peak demand reductions provided by these programs are expected to reduce future distribution system capacity requirements, but the precise locations and timing of the affected traditional investments are not known.

Consistent with the OEB BCA Framework, annual distribution system capacity benefits for the non-targeted portion of the demand response and EE programs were calculated using the following formula:

Annual Benefit = ΔPeakLoad ÷ (1 – Loss%) × DistCoincidenceFactor × DeratingFactor × MarginalDistCost

This formula was applied using the program forecast peak reductions and the assumptions described in the following sections to determine the annual distribution capacity benefits.

6. Annual Benefit Parameter Development

Table 1 summarizes the parameter values and the basis for each value used in calculating annual distribution system benefits for non-targeted NWS. The following sections provide additional detail on the methodology and derivation of each parameter

Table 1: Annual Distribution Capacity Benefit Parameter Values

Parameter	Value	Basis
Marginal distribution cost	$215.2/kW-year	Distribution system capacity cost annualized over a 50-year equipment life using a 9.30% total cost of capital
Change in peak load	Program forecast by year see Table 2	Expected net peak reduction delivered by mER and EE
Distribution losses	7.6%	Average distribution system losses applied to reflect NWS resources that are geographically dispersed relative to the distribution assets being deferred
Distribution coincidence factor	0.90	Historical experience with peak prediction tools indicates that event scheduling and dispatch of the residential demand response program closely align with system peak demand periods, supporting the application of a 0.90 coincidence factor for the program
Derating factor	1.00	Availability and performance is already incorporated in forecast peak reductions for the programs
Real social discount rate	4%	OEB-prescribed rate for NPV analysis

6.1 Marginal Distribution Cost

Hydro One developed the marginal distribution cost in three steps. First, Hydro One identified the distribution investments and forecast load growth appropriate for estimating the benefits of non-targeted NWS. Investments driven by asset condition, safety, reliability, customer-specific connections, and service transformer upgrades were excluded. The resulting eligible investment portfolio consisted of D-SS-01 feeder and station capacity investments driven by load growth.

Second, Hydro One calculated the average one-time capital cost of providing incremental distribution capacity by dividing the eligible investment portfolio of approximately $1.237 billion

(2026 dollars) by 541 MW of forecast distribution system load growth. This resulted in a marginal capital cost of $2,288/kW.

Third, Hydro One converted this one-time capital cost into an annual value using a **9.30% Total Cost of Capital** and a **50-year asset life**. See exhibit B-03-01_03.06-04.01, "03 Inputs and Assumptions" tab for detailed inputs to calculate the Total Cost of Capital. Applying the capital recovery factor resulted in an annualized marginal distribution cost of **$215.2/kW-year**, which was used to calculate distribution capacity benefits in the DST analysis.

6.2 Change in Peak Load (ΔPeakLoad)

ΔPeakLoad represents the peak demand reduction expected from each program. Forecasts shown in Table 2 below, reflect anticipated enrollment, participation, device performance, and program delivery.

Table 2: Forecast Cumulative Peak Load Reduction from Non-targeted Demand Response and EE Programs

Program	2028	2029	2030	2031	2032
Demand Response (MW)	35.9	40.6	43.9	46.9	49.4
EE (MW)	3.7	7.6	15.5	23.4	35.3

6.3 Distribution Loss Factor (Loss%)

Hydro One applied a 7.6% distribution loss factor, reflecting average system losses and the geographically dispersed nature of the NWS resources relative to the distribution assets being deferred. Consistent with the OEB BCA Framework, peak demand reductions were adjusted using 1 ÷ (1 − Loss%), resulting in a loss adjustment factor of 1.082.

6.4 Distribution Coincidence Factor

Hydro One applied a Distribution Coincidence Factor of 0.90 to reflect the expected alignment between program peak demand reductions and distribution system peak conditions.

The demand response program is dispatchable and can be activated during forecasted system peak events. Historical experience with peak prediction tools indicates that event scheduling and dispatch of the residential demand response program closely align with system peak demand periods, supporting the application of a 0.90 coincidence factor for the program.

EE measures reduce electricity consumption continuously and therefore provide savings during peak periods whenever customer load occurs, supporting the use of a 1.0 coincidence factor for this program.

For simplicity, a common coincidence factor of 0.90 was applied to both programs. The value is considered appropriate for demand response and conservative for EE, whose savings are expected to align very closely with peak demand conditions.

6.5 Derating Factor

Hydro One applied a Derating Factor of 1.00. The forecast peak reductions are net achievable values and already incorporate participant availability, device response, and expected program performance. An additional adjustment would therefore double-count derating.

6.6 Real social discount rate

Hydro one used the OEB-prescribed 4% real social discount rate to convert annual benefits and costs to net present value to determine the benefit-cost ratio.

7. Benefit-Cost Analysis Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the demand response and Local Energy Efficiency programs was assessed using the OEB's Benefit-Cost Analysis Framework. As summarized in **Table 3: DST Results** and **Table 4: EST Results**, both programs achieved benefit-cost ratios greater than 1 under the DST and the EST. Detailed benefit-cost analysis results, including all key model inputs and cost and benefit calculations, can be found at the following locations:

- DSP Section 3.6 – Attachment 1 - Appendix B – BCA Local Energy Efficiency Program Supporting Spreadsheets. This BCA is for EE programs.
- DSP Section 3.6 – Attachment 1 - Appendix B – BCA Demand Response Program Supporting Spreadsheets. This BCA is for demand response.

These excel-based models form the basis of the economic assessment and support the DST and EST results summarized in the tables below.

Table 3: DST Results

	Demand Response Program	Local EE Programs
NPV Cost of NWS ($M):	**7.42**	**43.50**
NPV Total Benefit of NWS ($M):	**38.67**	**87.56**
NPV Net Benefit ($M):	**31.25**	**44.05**
Benefit: Cost Ratio	**5.21**	**2.01**

Table 4: EST Results

	Demand Response Program	Local EE Programs
NPV Cost of NWS ($M):	**7.42**	**55.75**
NPV Total Benefit of NWS ($M):	**97.41**	**279.11**

NPV Net Benefit ($M):	**89.99**	**223.35**
Benefit: Cost Ratio	**13.13**	**5.01**

8. Risk Mitigation

The principal uncertainties associated with the non-targeted NWS programs relate to customer participation, realized peak demand reductions, and program costs.

Hydro One will monitor program performance, peak demand reductions, participation levels, and program costs throughout the planning period.

Program results will be used to adjust program design, delivery, and funding as required to maintain cost-effectiveness and ensure the programs continue to provide value to customers and the distribution system.

9. Final Result of NWS Viability / Outcome

Hydro One's assessment indicates that the demand response and Local Energy Efficiency programs are economically viable non-wires solutions. The programs achieved benefit-cost ratios greater than 1.0 under both the Distribution Service Test and Energy System Test, indicating that the distribution and broader electricity system benefits exceed the associated costs. Accordingly, Hydro One concludes that these programs represent cost-effective options for reducing future distribution capacity requirements and providing value to customers and the electricity system.

NWS Summary – Smithfield DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Smithfield DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Trenton area, located within Hydro One's Central zone, is forecast to increase loading on the existing 44kV:8.32kV, 5MVA station at Smithfield DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 6.00MVA. The summer peak load is forecast to increase by 1.20MVA by 2032, reaching 7.20MVA, which exceeds the station's 6.25MVA planning limit by 0.95MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Smithfield DS from 5MVA to 7.5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Smithfield DS is forecast to exceed its planning limit by 0.95**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.40**MW** by 2032, equivalent to 0.44**MVA** of load relief assuming a power factor of 0.92.

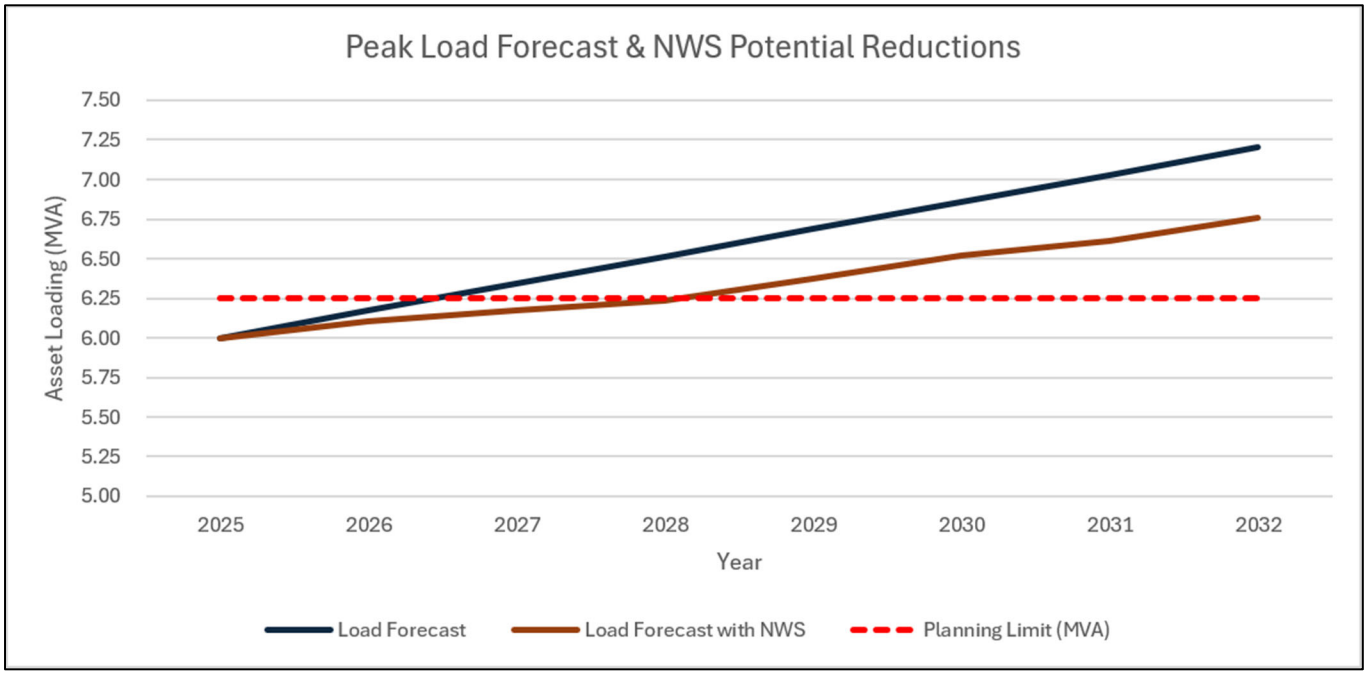
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Smithfield DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Smithfield DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.36**
NPV Total Benefit of NWS ($M):	**0.64**
NPV Net Benefit ($M):	**0.27**
Benefit: Cost Ratio	**1.75**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.40**
NPV Total Benefit if NWS ($M):	**1.25**
NPV Net Benefit ($M):	**0.85**
Benefit: Cost Ratio	**3.14**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Smithfield DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Southwold DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Southwold DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the area west of St.Thomas, located within Hydro One's South zone, is forecast to increase loading on the existing 27.6kV:8.32kV, 2.5MVA station at Southwold DS up to its 2.50MVA planning limit. The asset is summer constrained with a current summer peak demand load of 2.08MVA. The summer peak load is forecast to increase by 0.42MVA by 2032, reaching the station's 2.50MVA planning limit.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Southwold DS from 2.5MVA to 5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Southwold DS is forecast to reach its planning limit within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.12**MW** by 2032, equivalent to 0.13**MVA** of load relief assuming a power factor of 0.92.

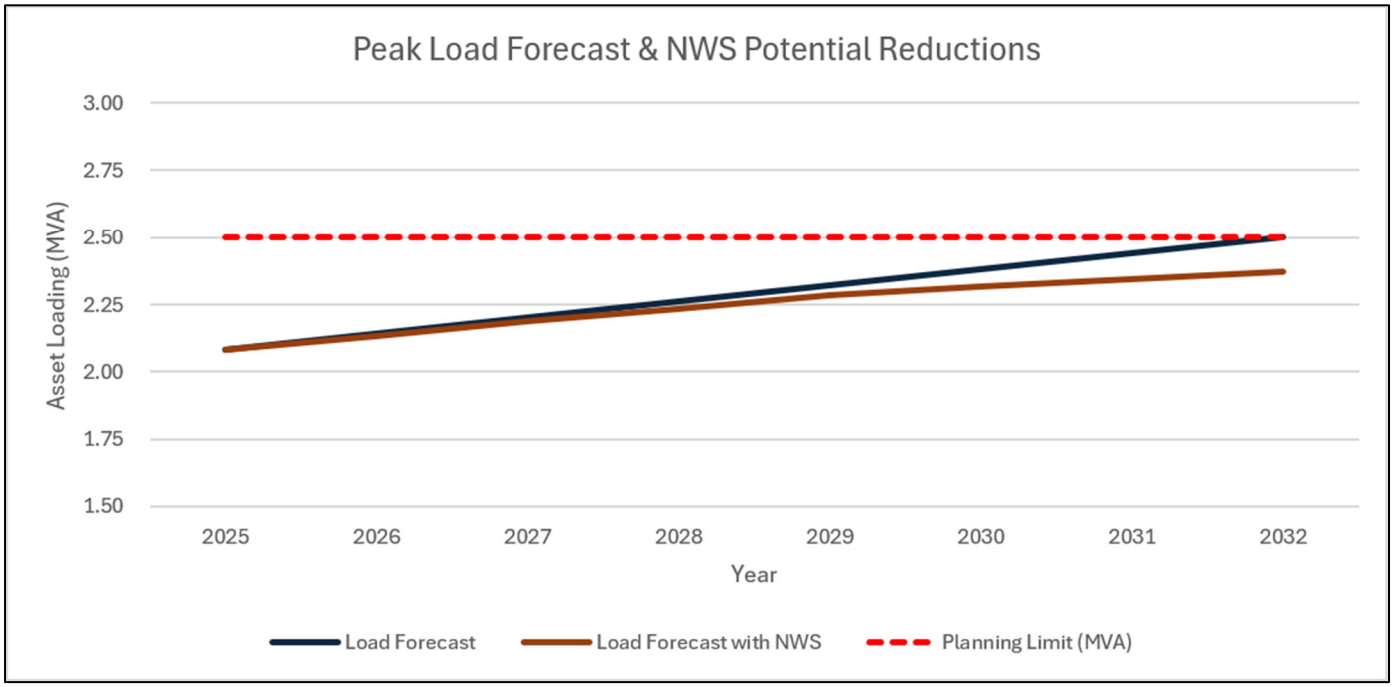
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Southwold DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Southwold DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.06**
NPV Total Benefit of NWS ($M):	**0.75**
NPV Net Benefit ($M):	**0.69**
Benefit: Cost Ratio	**11.85**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.09**
NPV Total Benefit if NWS ($M):	**0.92**
NPV Net Benefit ($M):	**0.83**
Benefit: Cost Ratio	**10.19**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Southwold DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Violet Hill DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Violet Hill DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the area east of Shelburne, located within Hydro One's Central zone, is forecast to increase loading on the existing 44kV:8.32kV, 5MVA station at Violet Hill DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 5.80MVA. The summer peak load is forecast to increase by 0.80MVA by 2032, reaching 6.60MVA, which exceeds the station's 6.25MVA planning limit by 0.35MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Violet Hill DS from 5MVA to 7.5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Violet Hill DS is forecast to exceed its planning limit by 0.35**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.41**MW** by 2032, equivalent to 0.44**MVA** of load relief assuming a power factor of 0.92.

The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Violet Hill DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

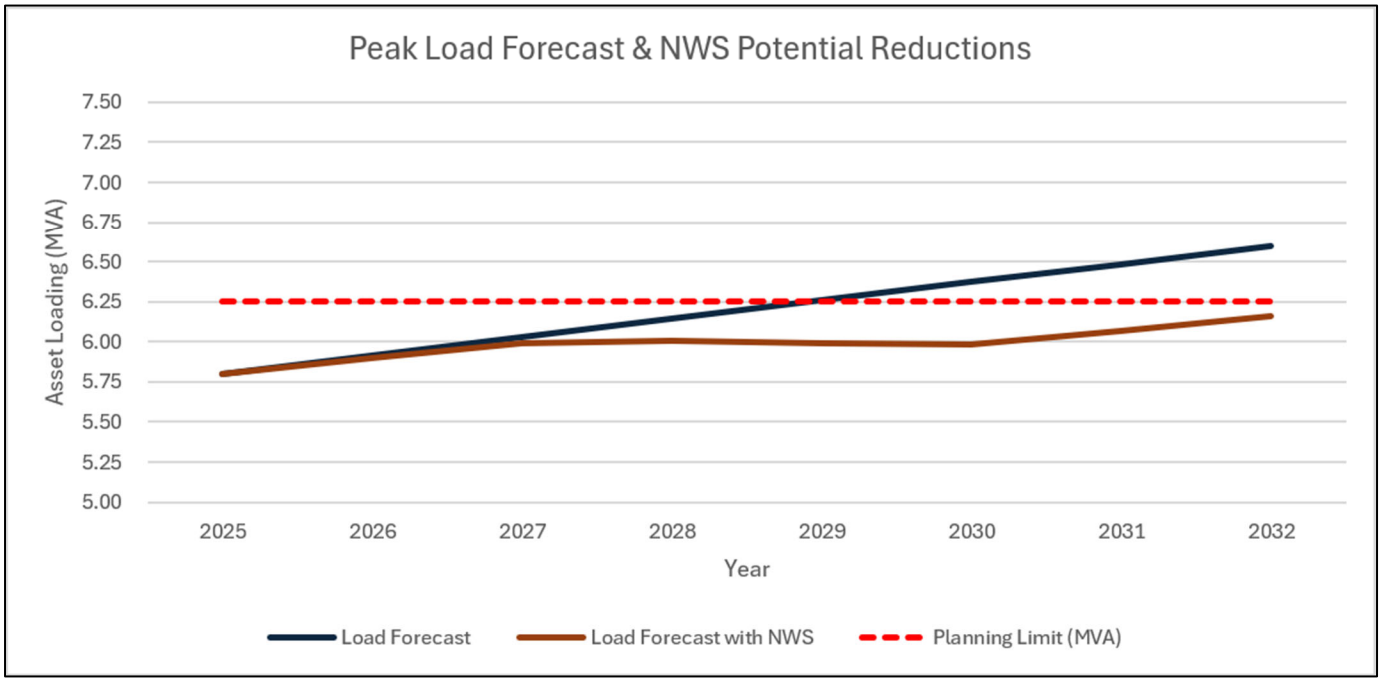
1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response

(DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Violet Hill DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.29**
NPV Total Benefit of NWS ($M):	**0.64**
NPV Net Benefit ($M):	**0.35**
Benefit: Cost Ratio	**2.21**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.32**
NPV Total Benefit if NWS ($M):	**1.14**
NPV Net Benefit ($M):	**0.82**
Benefit: Cost Ratio	**3.59**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Violet Hill DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Warwick DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Warwick DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the Watford area, located within Hydro One's South zone, is forecast to increase loading on the existing 27.6kV:8.32kV, 5MVA station at Warwick DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 5.37MVA. The summer peak load is forecast to increase by 1.63MVA by 2032, reaching 7.00MVA, which exceeds the station's 6.25MVA planning limit by 0.75MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Warwick DS from 5MVA to 7.5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Warwick DS is forecast to exceed its planning limit by 0.75**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.33**MW** by 2032, equivalent to 0.36**MVA** of load relief assuming a power factor of 0.92.

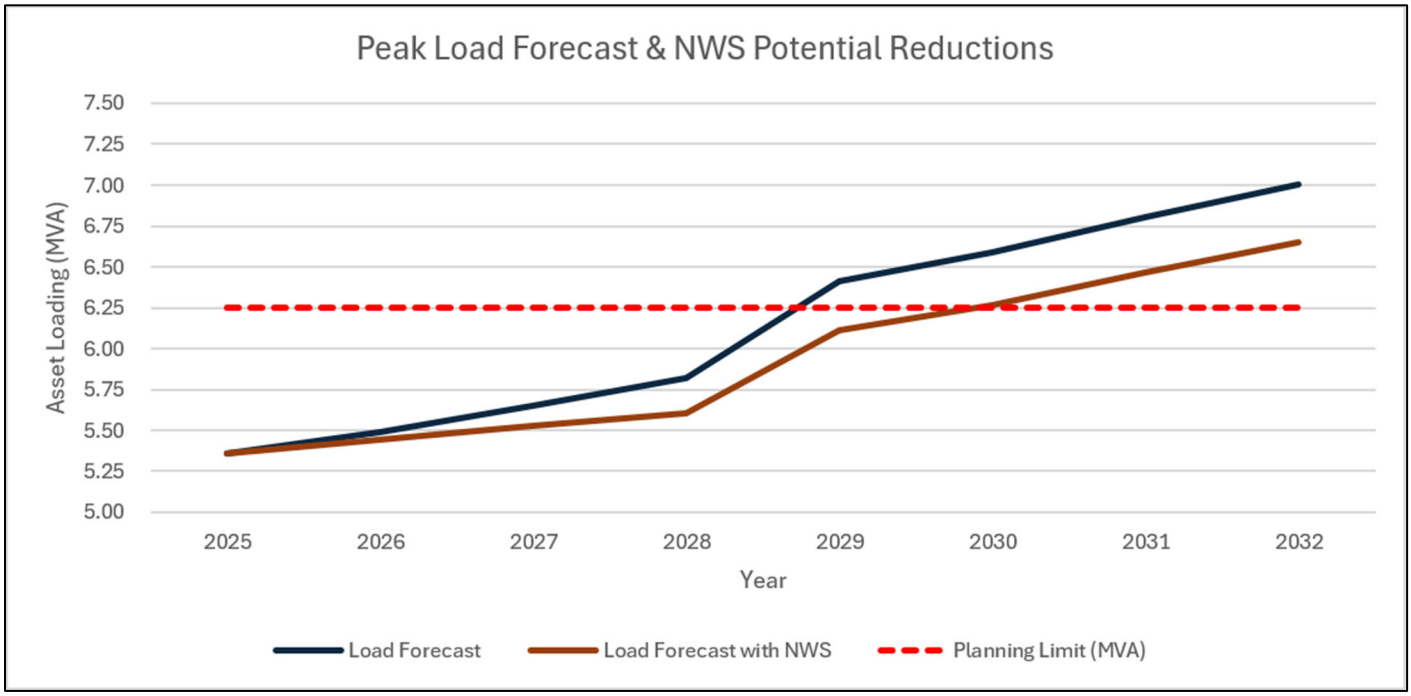
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Warwick DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Warwick DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.39**
NPV Total Benefit of NWS ($M):	**0.89**
NPV Net Benefit ($M):	**0.50**
Benefit: Cost Ratio	**2.30**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.42**
NPV Total Benefit if NWS ($M):	**1.43**
NPV Net Benefit ($M):	**1.01**
Benefit: Cost Ratio	**3.42**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Warwick DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – West Lorne DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the West Lorne DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the West Lorne area, located within Hydro One's South zone, is forecast to increase loading on the existing 27.6kV:8.32kV, 5MVA station at West Lorne DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 6.27MVA. The summer peak load is forecast to increase by 1.33MVA by 2032, reaching 7.60MVA, which exceeds the station's 6.25MVA planning limit by 1.35MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at West Lorne DS from 5MVA to 7.5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. West Lorne DS is forecast to exceed its planning limit by 1.35**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.38**MW** by 2032, equivalent to 0.41**MVA** of load relief assuming a power factor of 0.92.

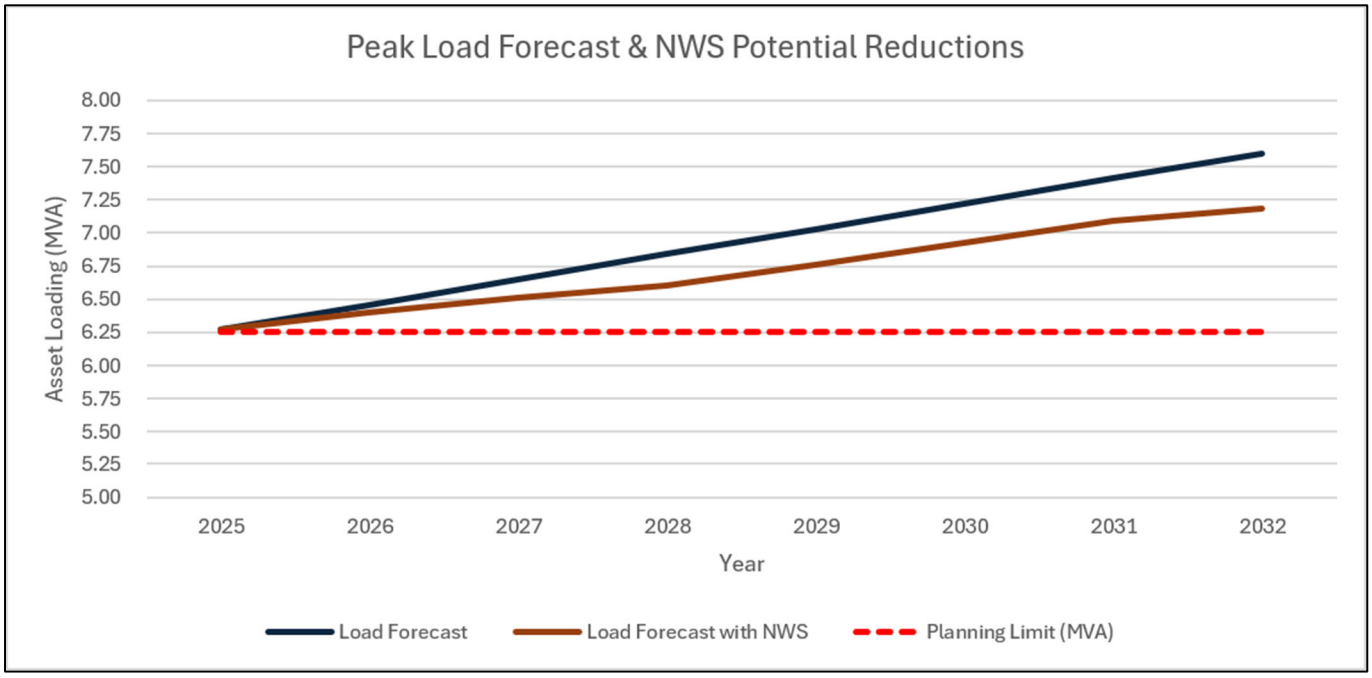
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – West Lorne DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at West Lorne DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.25**
NPV Total Benefit of NWS ($M):	**0.83**
NPV Net Benefit ($M):	**0.58**
Benefit: Cost Ratio	**3.32**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.29**
NPV Total Benefit if NWS ($M):	**1.34**
NPV Net Benefit ($M):	**1.05**
Benefit: Cost Ratio	**4.67**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at West Lorne DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Whitefish DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Whitefish DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the area west of Sudbury, located within Hydro One's North zone, is forecast to increase loading on the existing 44kV:12.5kV, 6MVA station at Whitefish DS up to its 9.30MVA planning limit. The asset is winter constrained with a current winter peak demand load of 7.00MVA. The winter peak load is forecast to increase by 2.30MVA by 2032, meeting the station's planning limit of 9.30MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Whitefish DS from 6MVA to 7.5/10/12.5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Whitefish DS is forecast to meet its planning limit within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.14**MW** by 2032, equivalent to 0.15**MVA** of load relief assuming a power factor of 0.95.

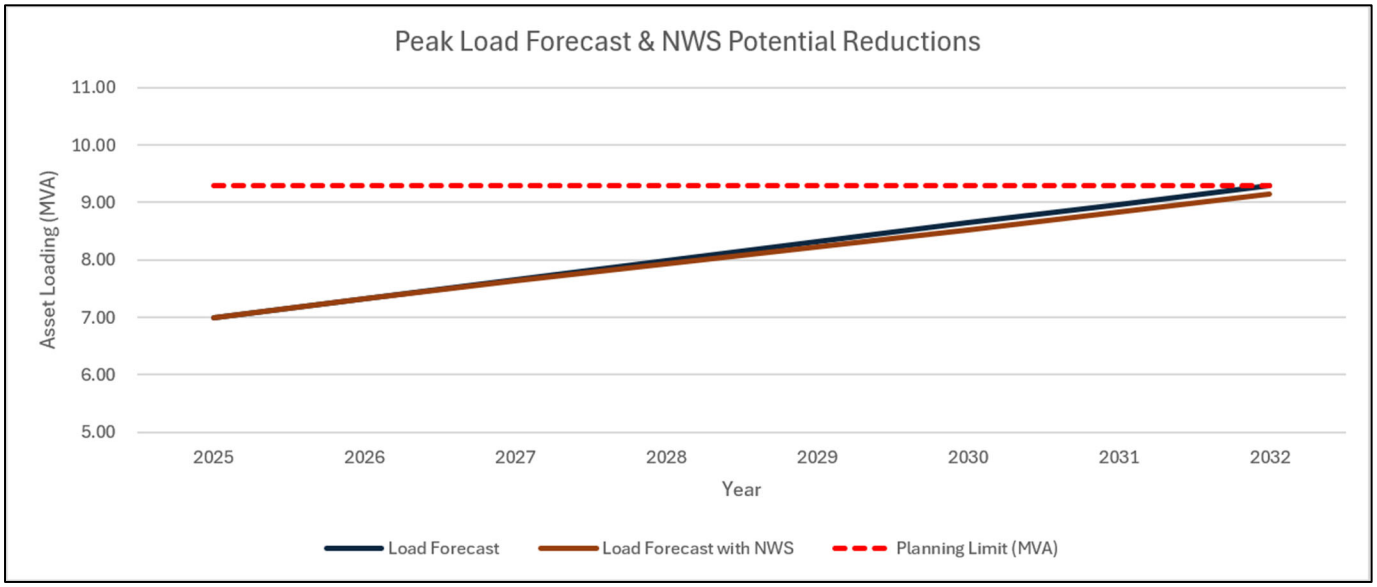
The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Whitefish DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response (DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Whitefish DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**1.14**
NPV Total Benefit of NWS ($M):	**1.85**
NPV Net Benefit ($M):	**0.71**
Benefit: Cost Ratio	**1.63**

Table 2: EST Results

NPV Cost of NWS ($M):	**1.18**
NPV Total Benefit if NWS ($M):	**2.44**
NPV Net Benefit ($M):	**1.26**
Benefit: Cost Ratio	**2.06**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Whitefish DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

NWS Summary – Wingham DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Wingham DS wires investment, including NWS considerations, an overview of the technical viability, and final results.

Need

Load growth in the Wingham area, located within Hydro One's South zone, is forecast to increase loading on the existing 44kV:8.32kV, 3MVA station at Wingham DS beyond its 3.75MVA planning limit. The asset is summer constrained with a current summer peak demand load of 4.20MVA. The summer peak load is forecast to increase by 2.00MVA by 2032, reaching 6.20MVA, which exceeds the station's 3.75MVA planning limit by 2.45MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Wingham DS from 3MVA to 7.5MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Not Viable. Wingham DS is forecast to exceed its planning limit by 2.45**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.77**MW** by 2032, equivalent to 0.83**MVA** of load relief assuming a power factor of 0.92, which is insufficient with respect to the asset's planning limit and the forecast load.

The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Wingham DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

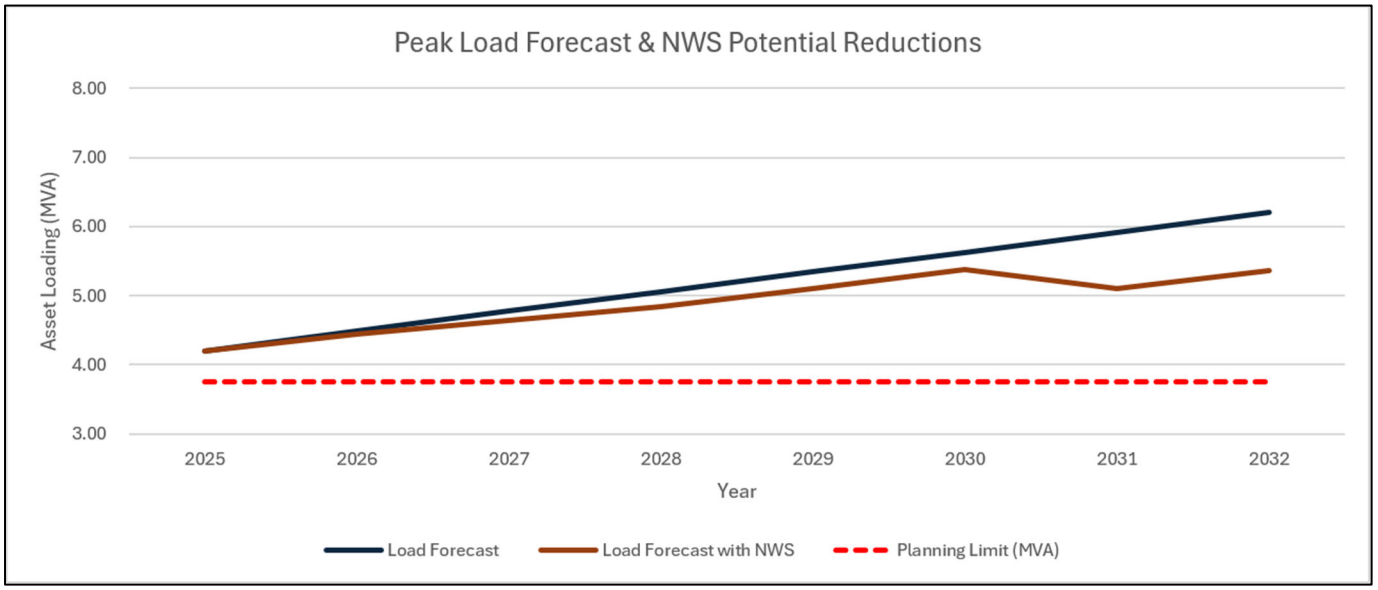
1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response

(DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS cannot defer the investment need based on the load forecast. As a result, Hydro One concludes that the proposed NWS is **not a technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Since Wingham DS did not pass the technical viability check, it did not proceed to an economic viability test, and the OEB's Benefit-Cost Analysis Framework was not applied. Accordingly, there are no results from the economic test.

Final result of NWS Viability / Outcome

Hydro One's assessment indicates that **NWS is not a viable option** for addressing the identified capacity need at Wingham DS. The system need is expected to be addressed through a conventional wires investment, estimated at a net cost of $7.0M. Since these capital costs had been removed from the capital plan in anticipation of NWS success, they will need to be reintroduced as a load growth investment under D-SS-01.

NWS Summary – Woodland Beach DS

Introduction

This report provides an overview of the viability of a Non-Wires Solution (NWS) with respect to the Woodland Beach DS wires investment, including NWS considerations, an overview of the technical viability, economic viability, and final results.

Need

Load growth in the area north of Wasaga Beach, located within Hydro One's Central zone, is forecast to increase loading on the existing 44kV:8.32kV, 5MVA station at Woodland Beach DS beyond its 6.25MVA planning limit. The asset is summer constrained with a current summer peak demand load of 6.00MVA. The summer peak load is forecast to increase by 0.77MVA by 2032, reaching 6.67MVA, which exceeds the station's 6.25MVA planning limit by 0.52MVA.

Alternatives Considered

1. Reference Scenario (Wires): Increase the station capacity at Woodland Beach DS from 5MVA to 10MVA, to support identified growth.
2. NWS: Leverage a combination of load flexibility, energy efficiency from residential and Commercial & Industrial (C&I) customers, and Distributed Energy Resources (DER) to reduce peak loading on the station.

Hydro One Assessment of Technical Viability

Technical Viability Conclusion: Technically Viable. Woodland Beach DS is forecast to exceed its planning limit by 0.52**MVA** within the forecast period. The proposed NWS is expected to achieve a cumulative peak demand reduction of 0.37**MW** by 2032, equivalent to 0.40**MVA** of load relief assuming a power factor of 0.92.

The technical viability assessment is based on the NWS potential study completed by Posterity Group. Detailed results, and achievable potential estimates are provided in DSP Section 3.6 – Attachment 1 - Appendix C – Woodland Beach DS Technical Analysis**.** Note that the results of the potential study completed by Posterity Group may show slightly different results from those shown in this Summary. This is due to the following:

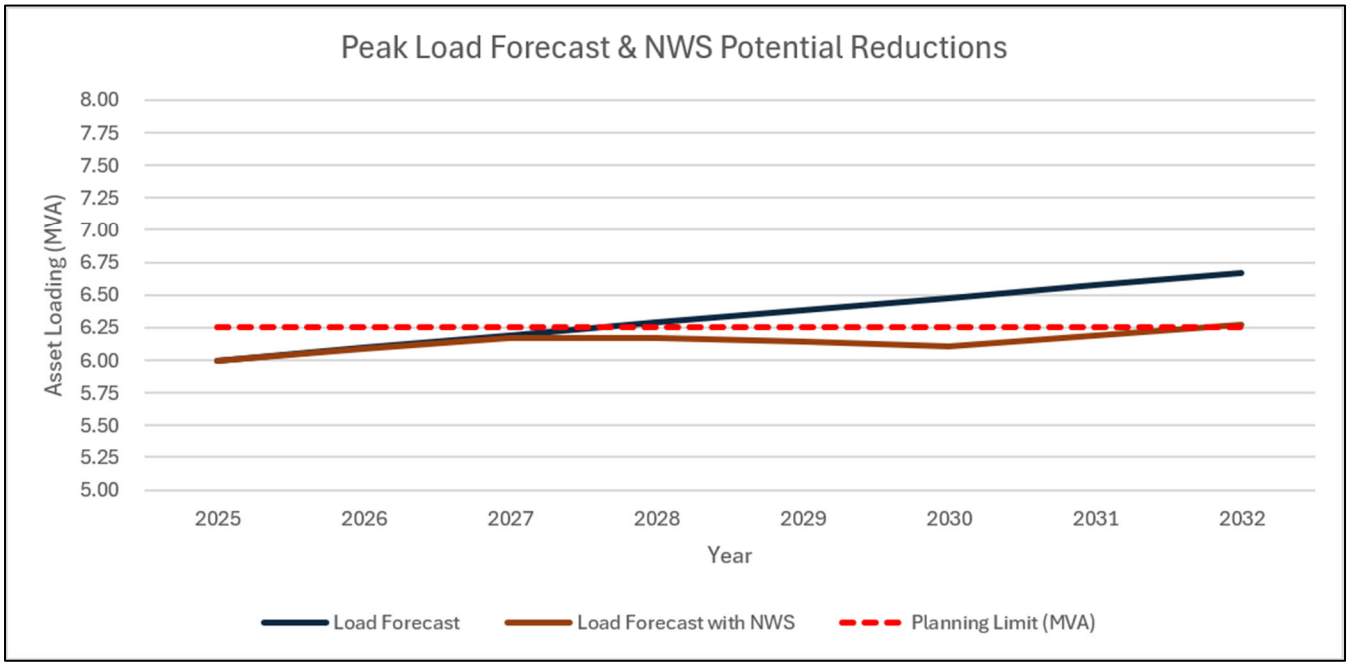
1. Timing of measures: HONI may choose to implement measures earlier or later, depending on the technical need. For example, if the planning limit is anticipated to be reached early in the proposed rate period, Demand Response

(DR) measures may be applied earlier than implemented in the potential study completed by Posterity Group.

2. Amount of peak reduction required: HONI may implement a lower amount of NWS resources, depending on the asset needs and cost. For example, if 100kW of flexible load could be acquired, but only 50kW is needed, the lower amount may be used.

As illustrated in **Figure 1**, based on the forecast load growth and achievable NWS potential, Hydro One expects the proposed NWS to defer the need for the investment based on the load forecast. As a result, Hydro One concludes that the proposed NWS is a **technically viable** option for addressing the identified capacity need.

Figure 1: Peak Load Forecast & NWS Potential Reductions



BCA Assessment of Economic Viability

Economic Viability Conclusion: Economically Viable. The economic viability of the proposed NWS was assessed using the OEB's Benefit-Cost Analysis Framework. The analysis assumed that the proposed NWS would defer the traditional wires investment beyond 2032. This assumed deferral period was used to calculate the Distribution Service Test (DST) and Energy System Test (EST) benefit-cost ratios.

As summarized in **Table 1: DST Results** and **Table 2: EST Results**, the proposed NWS achieved a benefit-cost ratio greater than 1 under the DST and greater than 1 under the EST, indicating that the value of deferring the traditional wires investment exceeds the cost of implementing the NWS measures. Accordingly, Hydro One concludes that the proposed NWS is **economically viable** and represents a cost-effective approach to addressing the identified capacity need at Woodland Beach DS. Detailed benefit-cost analysis results, including all key model inputs and benefit-cost calculations, are provided in DSP Section 3.6 – Attachment 1 - Appendix B – BCA Supporting Spreadsheets. This Excel-based model forms the basis of the economic assessment and supports the DST and EST results summarized in the tables below.

Table 1: DST Results

NPV Cost of NWS ($M):	**0.22**
NPV Total Benefit of NWS ($M):	**0.64**
NPV Net Benefit ($M):	**0.42**
Benefit: Cost Ratio	**2.95**

Table 2: EST Results

NPV Cost of NWS ($M):	**0.22**
NPV Total Benefit if NWS ($M):	**1.18**
NPV Net Benefit ($M):	**0.95**
Benefit: Cost Ratio	**5.24**

Risk Mitigation

Ongoing monitoring of peak demand loading will be compared against growth rates and NWS resource availability to evaluate overall efficacy of the non-wires solution. Monitoring will support an adaptive planning approach, allowing Hydro to advance, or continue to defer investments based on load growth and NWS acquisition and performance. Hydro One will initiate procurement of NWS in advance of the identified need to increase the likelihood that sufficient NWS can be obtained.

Final result of NWS Viability / Outcome

As outlined in DSP Section 3.7, Hydro One applies a risk-based approach to pace and prioritize system investments. Similarly for NWS, potential solutions are considered technically viable if they maintain loading within, or close to, the asset's planning limit. In determining the suitability of the timing for NWS investments, Hydro One considers the level of risk associated with investment deferral and forecast amounts of peak reduction resulting from NWS. This approach ensures proposed NWS meet their objective of cost benefits resulting from investment deferral, while also managing risks associated with asset overload.

Hydro One's assessment indicates that the proposed NWS is a **technically and economically viable** option for addressing the identified capacity need at Woodland Beach DS. The forecast peak demand reduction is sufficient to defer the traditional wires investment, while the economic assessment demonstrates that the benefits of the NWS exceed the associated costs.

SECTION 3.6 – ATTACHMENT 04.01 - BCA MYENERGY REWARDS PROGRAM SUPPORTING SPREADSHEETS

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SECTION 3.6 – ATTACHMENT 04.02 - BCA LOCAL ENERGY EFFICIENCY PROGRAM SUPPORTING SPREADSHEETS

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SECTION 3.6 – ATTACHMENT 04.03 - BCA SUPPORTING SPREADSHEETS

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SECTION 3.6 – ATTACHMENT 04.04 – KASHABOWIE HVDS BCA

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HONI NWS Analysis
Birr DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Birr DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.10 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.44 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.172M	Total customer incentive costs associated with NWS measures
$0.161M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Birr DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 0.99 MVA across the forecast period, for a projected peak of 6.35 MVA by the end of the forecast period. This forecast growth is 0.10 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10.00	-	$0.000	$0.000
3	30.00	10.00	$0.013	$0.002
4	50.00	140.00	$0.037	$0.025
5	70.00	210.00	$0.040	$0.030
6	90.00	270.00	$0.039	$0.035
7	110.00	280.00	$0.022	$0.035
8	120.00	280.00	$0.021	$0.035

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.41 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	120
HONI EE (Residential / Commercial / Industrial)	40
DR Peak Reduction (Residential)	170
Flexibility (Commercial / Industrial)	80
Total	410

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	73,920	10
4	134,280	140
5	182,890	210
6	216,410	270
7	249,440	280
8	281,520	280
9	318,070	210
10	326,470	210

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.41 MW. At an expected power factor of 0.92, this translates to 0.44 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Carleton Place Francis DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Carleton Place Francis DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.02 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.52 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.291M	Total customer incentive costs associated with NWS measures
$0.200M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Carleton Place Francis DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 0.57 MVA across the forecast period, for a projected peak of 6.27 MVA by the end of the forecast period. This forecast growth is 0.02 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	20	-	$0.000	$0.000
3	30	10	$0.024	$0.003
4	60	190	$0.059	$0.028
5	80	250	$0.067	$0.036
6	100	310	$0.065	$0.044
7	130	320	$0.039	$0.044
8	150	330	$0.037	$0.044

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.48 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	150
HONI EE (Residential / Commercial / Industrial)	60
DR Peak Reduction (Residential)	140
Flexibility (Commercial / Industrial)	130
Total	480

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	82,130	10
4	156,660	190
5	219,620	250
6	266,290	310
7	309,670	320
8	348,040	330
9	389,640	200
10	397,410	210

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.48 MW. At an expected power factor of 0.92, this translates to 0.52 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Chesterville M1 Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Chesterville M1 Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

2.00 MVA	Hydro One's forecast load above the planning limit within the forecast period
2.03 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.811M	Total customer incentive costs associated with NWS measures
$0.373M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Chesterville TS M1 (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 4.00 MVA across the forecast period, for a projected peak of 32.00 MVA by the end of the forecast period. This forecast growth is 2.00 MVA above the asset planning limit of 30.00 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	50	-	$0.000	$0.000
3	100	20	$0.050	$0.006
4	170	910	$0.166	$0.042
5	240	1,160	$0.186	$0.064
6	290	1,420	$0.181	$0.086
7	350	1,440	$0.111	$0.087
8	410	1,460	$0.117	$0.088

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 1.87 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	410
HONI EE (Residential / Commercial / Industrial)	110
DR Peak Reduction (Residential)	630
Flexibility (Commercial / Industrial)	730
Total	1870

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	305,680	20
4	532,370	900
5	708,960	1,150
6	829,520	1,400
7	938,930	1,420
8	1,057,210	1,440
9	1,197,310	740
10	1,215,830	760

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 1.87 MW. At an expected power factor of 0.92, this translates to 2.03 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Dixons Corners DS

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Dixons Corners DS
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.65 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.38 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.120M	Total customer incentive costs associated with NWS measures
$0.172M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Dixons Corners DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 1.57 MVA across the forecast period, for a projected peak of 6.90 MVA by the end of the forecast period. This forecast growth is 0.65 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10.00	-	$0.000	$0.000
3	20.00	-	$0.004	$0.001
4	30.00	120.00	$0.026	$0.024
5	40.00	200.00	$0.033	$0.031
6	50.00	270.00	$0.033	$0.039
7	60.00	280.00	$0.011	$0.039
8	70.00	280.00	$0.013	$0.039

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.35 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	70
HONI EE (Residential / Commercial / Industrial)	10
DR Peak Reduction (Residential)	190
Flexibility (Commercial / Industrial)	80
Total	350

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	72,740	-
4	119,480	120
5	153,050	200
6	173,500	270
7	194,690	280
8	218,530	280
9	245,710	210
10	252,100	220

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.35 MW. At an expected power factor of 0.92, this translates to 0.38 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Fergusonvale DS Transformer Upgrade

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Fergusonvale DS Transformer Upgrade
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.60 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.40 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.105M	Total customer incentive costs associated with NWS measures
$0.149M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Fergusonvale DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 0.98 MVA across the forecast period, for a projected peak of 6.98 MVA by the end of the forecast period. This forecast growth is 0.73 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10.00	-	$0.000	$0.000
3	20.00	-	$0.009	$0.001
4	40.00	70.00	$0.022	$0.024
5	50.00	170.00	$0.026	$0.028
6	70.00	270.00	$0.026	$0.032
7	80.00	270.00	$0.011	$0.032
8	90.00	270.00	$0.011	$0.032

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.37 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	90
HONI EE (Residential / Commercial / Industrial)	20
DR Peak Reduction (Residential)	250
Flexibility (Commercial / Industrial)	10
Total	370

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	90,650	-
4	154,110	70
5	202,210	170
6	233,690	270
7	264,850	270
8	296,000	270
9	331,390	270
10	340,720	280

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.37 MW. At an expected power factor of 0.92, this translates to 0.40 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Horsey Bay DS T2 Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Horsey Bay DS T2 Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

1.15 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.50 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.178M	Total customer incentive costs associated with NWS measures
$0.212M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Horsey Bay DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 0.80 MVA across the forecast period, for a projected peak of 7.40 MVA by the end of the forecast period. This forecast growth is 1.15 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	20	-	$0.000	$0.000
3	30	10	$0.014	$0.002
4	60	90	$0.040	$0.028
5	80	200	$0.049	$0.038
6	100	310	$0.048	$0.048
7	120	310	$0.014	$0.048
8	140	320	$0.012	$0.048

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.46 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	140
HONI EE (Residential / Commercial / Industrial)	40
DR Peak Reduction (Residential)	270
Flexibility (Commercial / Industrial)	4
Total	460

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	97,740	10
4	168,520	90
5	222,310	200
6	256,780	310
7	289,120	310
8	318,900	320
9	353,120	310
10	360,790	320

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.46 MW. At an expected power factor of 0.92, this translates to 0.50 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Kingsville Pulford DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Kingsville Pulford DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.07 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.43 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.210M	Total customer incentive costs associated with NWS measures
$0.257M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Kingsville Pulford DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 1.02 MVA across the forecast period, for a projected peak of 5.82 MVA by the end of the forecast period. This forecast growth is 0.07 MVA above the asset planning limit of 5.75 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10.00	-	$0.000	$0.000
3	20.00	-	$0.006	$0.001
4	30.00	160.00	$0.046	$0.030
5	50.00	230.00	$0.062	$0.045
6	60.00	300.00	$0.064	$0.060
7	70.00	310.00	$0.016	$0.061
8	80.00	310.00	$0.016	$0.061

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.39 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	80
HONI EE (Residential / Commercial / Industrial)	20
DR Peak Reduction (Residential)	190
Flexibility (Commercial / Industrial)	100
Total	390

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	58,880	-
4	101,270	160
5	134,540	230
6	156,660	300
7	179,540	310
8	202,710	310
9	228,570	210
10	236,050	220

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.39 MW. At an expected power factor of 0.92, this translates to 0.43 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Lanark DS Load growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Lanark DS Load growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.55 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.79 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.325M	Total customer incentive costs associated with NWS measures
$0.229M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Lanark DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Both peak demand is forecast to increase by 1.80 MVA across the forecast period, for a projected peak of 6.80 MVA by the end of the forecast period. This forecast growth is 0.55 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10	-	$0.000	$0.000
3	20	-	$0.010	$0.001
4	30	460	$0.067	$0.028
5	50	550	$0.080	$0.040
6	60	630	$0.082	$0.053
7	70	640	$0.043	$0.053
8	90	640	$0.043	$0.053

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.73 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	90
HONI EE (Residential / Commercial / Industrial)	20
DR Peak Reduction (Residential)	220
Flexibility (Commercial / Industrial)	410
Total	730

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	103,640	-
4	176,310	460
5	230,400	540
6	264,800	620
7	299,210	630
8	334,020	630
9	373,600	240
10	384,760	250

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.73 MW. At an expected power factor of 0.92, this translates to 0.79 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
New Bragg DS and feeders

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: New Bragg DS and feeders
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

1.90 MVA	Hydro One's forecast load above the planning limit within the forecast period
1.40 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.747M	Total customer incentive costs associated with NWS measures
$0.563M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Curve Inn DS T2 (F4 F5) (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 1.70 MVA across the forecast period, for a projected peak of 15.70 MVA by the end of the forecast period. This forecast growth is 1.90 MVA above the asset planning limit of 13.80 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	60	-	$0.000	$0.000
3	110	30	$0.050	$0.007
4	200	290	$0.161	$0.054
5	280	520	$0.202	$0.094
6	360	740	$0.201	$0.135
7	430	760	$0.068	$0.136
8	500	790	$0.065	$0.137

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 1.29 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	500
HONI EE (Residential / Commercial / Industrial)	200
DR Peak Reduction (Residential)	490
Flexibility (Commercial / Industrial)	100
Total	1290

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	155,310	30
4	304,310	290
5	429,000	510
6	523,650	730
7	611,300	760
8	688,720	790
9	782,230	730
10	798,340	750

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 1.29 MW. At an expected power factor of 0.92, this translates to 1.40 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Smithfield DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Smithfield DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.95 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.44 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.186M	Total customer incentive costs associated with NWS measures
$0.199M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Smithfield DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 1.20 MVA across the forecast period, for a projected peak of 7.20 MVA by the end of the forecast period. This forecast growth is 0.95 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10	-	$0.000	$0.000
3	30	-	$0.013	$0.002
4	40	120	$0.040	$0.027
5	60	200	$0.049	$0.036
6	80	280	$0.048	$0.045
7	100	290	$0.018	$0.045
8	110	290	$0.018	$0.045

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.40 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	110
HONI EE (Residential / Commercial / Industrial)	30
DR Peak Reduction (Residential)	200
Flexibility (Commercial / Industrial)	60
Total	400

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	89,870	-
4	157,020	110
5	209,420	200
6	244,060	280
7	277,410	280
8	309,690	290
9	344,800	240
10	352,790	240

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.40 MW. At an expected power factor of 0.92, this translates to 0.44 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Southwold DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Southwold DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.00 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.13 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.081M	Total customer incentive costs associated with NWS measures
$0.123M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Southwold DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 0.42 MVA across the forecast period, for a projected peak of 2.50 MVA by the end of the forecast period. This forecast growth reaches the asset planning limit of 2.50 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10.00	-	$0.000	$0.000
3	10.00	-	$0.009	$0.001
4	20.00	20.00	$0.017	$0.022
5	20.00	50.00	$0.018	$0.024
6	30.00	70.00	$0.017	$0.025
7	40.00	80.00	$0.010	$0.025
8	40.00	80.00	$0.010	$0.025

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.12 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	40
HONI EE (Residential / Commercial / Industrial)	10
DR Peak Reduction (Residential)	60
Flexibility (Commercial / Industrial)	4
Total	120

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	41,640	-
4	77,510	20
5	107,450	50
6	128,950	70
7	149,880	80
8	170,070	80
9	192,510	80
10	197,800	80

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.12 MW. At an expected power factor of 0.92, this translates to 0.13 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Violet Hill DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Violet Hill DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.35 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.45 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.175M	Total customer incentive costs associated with NWS measures
$0.227M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Violet Hill DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 0.80 MVA across the forecast period, for a projected peak of 6.60 MVA by the end of the forecast period. This forecast growth is 0.35 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	20.00	-	$0.000	$0.000
3	30.00	10.00	$0.010	$0.001
4	50.00	80.00	$0.038	$0.029
5	70.00	170.00	$0.050	$0.040
6	90.00	270.00	$0.050	$0.052
7	110.00	280.00	$0.013	$0.052
8	130.00	280.00	$0.013	$0.052

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.41 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	130
HONI EE (Residential / Commercial / Industrial)	40
DR Peak Reduction (Residential)	240
Flexibility (Commercial / Industrial)	10
Total	410

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	62,530	10
4	110,090	80
5	148,720	170
6	175,170	270
7	201,690	280
8	226,870	280
9	255,800	290
10	263,340	300

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.41 MW. At an expected power factor of 0.92, this translates to 0.45 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Warwick DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Warwick DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.75 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.35 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.172M	Total customer incentive costs associated with NWS measures
$0.191M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Warwick DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 1.63 MVA across the forecast period, for a projected peak of 7.00 MVA by the end of the forecast period. This forecast growth is 0.75 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10.00	-	$0.000	$0.000
3	20.00	-	$0.010	$0.001
4	30.00	110.00	$0.036	$0.026
5	50.00	170.00	$0.044	$0.034
6	60.00	230.00	$0.044	$0.043
7	70.00	240.00	$0.018	$0.043
8	80.00	240.00	$0.019	$0.043

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.33 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	80
HONI EE (Residential / Commercial / Industrial)	20
DR Peak Reduction (Residential)	160
Flexibility (Commercial / Industrial)	60
Total	330

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	71,570	-
4	126,470	110
5	171,090	170
6	201,900	230
7	234,080	240
8	268,190	240
9	306,740	190
10	315,120	190

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.33 MW. At an expected power factor of 0.92, this translates to 0.35 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
West Lorne DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: West Lorne DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

1.35 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.41 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.156M	Total customer incentive costs associated with NWS measures
$0.159M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for West Lorne DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 1.33 MVA across the forecast period, for a projected peak of 7.60 MVA by the end of the forecast period. This forecast growth is 1.35 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10.00	-	$0.000	$0.000
3	30.00	-	$0.012	$0.002
4	50.00	110.00	$0.032	$0.024
5	70.00	180.00	$0.037	$0.029
6	80.00	240.00	$0.036	$0.034
7	100.00	250.00	$0.020	$0.034
8	120.00	260.00	$0.020	$0.035

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.37 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	120
HONI EE (Residential / Commercial / Industrial)	30
DR Peak Reduction (Residential)	160
Flexibility (Commercial / Industrial)	60
Total	370

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	62,630	-
4	113,200	110
5	154,810	180
6	184,590	240
7	214,050	250
8	242,970	260
9	274,340	200
10	280,880	210

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.37 MW. At an expected power factor of 0.92, this translates to 0.41 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Whitefish DS Upgrade - Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Whitefish DS Upgrade - Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.70 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.19 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.120M	Total customer incentive costs associated with NWS measures
$0.111M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Whitefish DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.95.

3 Load Forecast and Capacity Need

Hydro One's Winter peak demand is forecast to increase by 3.00 MVA across the forecast period, for a projected peak of 10.00 MVA by the end of the forecast period. This forecast growth is 0.70 MVA above the asset planning limit of 9.30 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10	-	$0.000	$0.000
3	20	-	$0.014	$0.002
4	30	60	$0.023	$0.022
5	40	70	$0.022	$0.022
6	50	90	$0.020	$0.022
7	60	100	$0.020	$0.022
8	70	110	$0.021	$0.022

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.18MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	70
HONI EE (Residential / Commercial / Industrial)	30
DR Peak Reduction (Residential)	40
Flexibility (Commercial / Industrial)	40
Total	180

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 25-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	109,040	-
4	186,110	50
5	244,560	70
6	282,440	90
7	320,560	100
8	359,750	100
9	407,010	70
10	415,370	70

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.18MW. At an expected power factor of 0.95, this translates to 0.19 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Wingham DS Load Growth

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Wingham DS Load Growth
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

2.45 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.34 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.144M	Total customer incentive costs associated with NWS measures
$0.182M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Wingham DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 2.00 MVA across the forecast period, for a projected peak of 6.20 MVA by the end of the forecast period. This forecast growth is 2.45 MVA above the asset planning limit of 3.75 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10	-	$0.000	$0.000
3	20	-	$0.009	$0.001
4	30	100	$0.030	$0.025
5	40	160	$0.038	$0.033
6	50	230	$0.039	$0.041
7	60	230	$0.014	$0.041
8	70	240	$0.014	$0.041

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.31 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	70
HONI EE (Residential / Commercial / Industrial)	20
DR Peak Reduction (Residential)	170
Flexibility (Commercial / Industrial)	50
Total	310

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	61,140	-
4	109,380	90
5	148,620	160
6	175,060	230
7	202,780	230
8	232,340	240
9	266,070	190
10	273,960	200

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.31 MW. At an expected power factor of 0.92, this translates to 0.34 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

HONI NWS Analysis
Woodland Beach DS Transformer Upgrade

Project: Hydro One Networks Inc. Non-Wires Solutions Analysis
Re: Woodland Beach DS Transformer Upgrade
Submitted to: Hydro One Networks Inc.

Analysis Summary

Table 1 - NWS Analysis Summary[1]

0.42 MVA	Hydro One's forecast load above the planning limit within the forecast period
0.49 MVA[2]	Potential peak reduction from NWS measures within the forecast period
$0.123M	Total customer incentive costs associated with NWS measures
$0.183M	Total non-incentive costs associated with NWS measures

1 Introduction

This report presents the results of a Non-Wires Solution (NWS) analysis for Woodland Beach DS (the 'asset'), evaluating the potential to reduce peak hour demand through a combination of Energy Efficiency (EE) and Demand Response (DR) over a prescribed timeline.

The analysis applies a standardized screening methodology using asset-level load forecasts, customer segmentation, and assumptions for NWS participation and performance. The results represent the achievable program potential of NWS to address the asset's needs and are intended to support system planning.

2 Purpose and Decision Context

The purpose of this report is to determine whether selected NWS measures could materially reduce the forecast peak demand at the asset, and by doing so, support the deferral of a capital project to increase capacity.

The analysis assesses the achievable peak reduction and provides estimated annual program costing to inform the Benefit-Cost Analysis (BCA) step of Hydro One's NWS process.

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[1] Values in this report may not sum precisely to totals due to rounding.
[2] At an expected power factor of 0.92.

3 Load Forecast and Capacity Need

Hydro One's Summer peak demand is forecast to increase by 0.67 MVA across the forecast period, for a projected peak of 6.67 MVA by the end of the forecast period. This forecast growth is 0.42 MVA above the asset planning limit of 6.25 MVA.

4 NWS Peak Reduction and Spending

The table below summarizes the projected year-over-year increase in potential peak reduction and associated NWS program costs.

Table 2 - NWS Program Peak Reduction and Spending

Year	Cumulative Peak Reduction from IESO-funded EE (kW)[3]	Cumulative Peak Reduction from HONI-funded NWS (kW)	Annual NWS Program Incentive Costs ($M)[4]	Annual NWS Program Non-Incentive Costs ($M)
1	-	-	$0.000	$0.000
2	10	-	$0.000	$0.000
3	20	-	$0.003	$0.000
4	30	150	$0.027	$0.025
5	50	260	$0.036	$0.033
6	60	360	$0.036	$0.042
7	70	370	$0.010	$0.042
8	80	370	$0.010	$0.042

5 NWS Measures – Forecast Outcomes

Based on the selected NWS measures, listed in Table 3 below, a forecasted total peak reduction of 0.45 MW by the end of the forecast period is achievable in this area.

[3] Cumulative peak reduction from IESO-funded EE includes increased Stream 1 and Stream 2 savings expected under new programs and incentives introduced by the 12-year electricity Demand Side Management Framework. These savings are in addition to the savings from existing CDM programs that have been captured in HONI's load forecast.

[4] As described in the BCA Framework, Incentive Costs are payments to individual third parties.

Table 3 - Forecasted Total Peak Load Reduction in Year 8 by NWS Measure Type

NWS Measure(s)	Forecast Total Peak Load Reduction (kW)
IESO EE (Residential / Commercial / Industrial)	80
HONI EE (Residential / Commercial / Industrial)	10
DR Peak Reduction (Residential)	270
Flexibility (Commercial / Industrial)	80
Total	450

6 NWS Energy and Peak Demand Savings

The table below summarizes the projected cumulative energy and peak demand savings associated with HONI EE and DR implementation, including consideration of measure life. This 10-year view is intended to assist with populating the EST portion of a BCA if required.

Table 4 – Cumulative Forecasted Energy and Peak Demand Savings

Year	Forecast Energy Savings (kWh)	Forecast Peak Demand Savings (kW)
1	-	-
2	-	-
3	54,940	-
4	90,500	150
5	116,680	250
6	132,870	360
7	149,300	360
8	166,420	370
9	185,510	290
10	190,990	300

7 Conclusion

The analysis demonstrates that the selected NWS measures can reduce peak demand by 0.45 MW. At an expected power factor of 0.92, this translates to 0.49 MVA of reduced loading on the asset by the end of the forecast period. Results represent the estimated potential under the modeled assumptions and depend on achieving target customer participation and other program delivery requirements.

SECTION 3.7 – DSP – INVESTMENT PLANNING PROCESS

3.7.1 INTRODUCTION

Hydro One's distribution system planning process is a risk-informed, value-based framework used to identify asset, system, customer, and regulatory needs across the distribution network; evaluate potential solutions; and prioritize investments that deliver customer and system value while maintaining affordability. The process supports investments that align with Hydro One's strategic priorities, customer preferences, legislative and regulatory obligations, and the Ontario Energy Board's Renewed Regulatory Framework ("RRF") outcomes.

The enterprise investment planning framework is described in SPF Section 1.7. This Section explains how that framework is applied to Hydro One Distribution and provides the line of sight between the detailed planning evidence in the Distribution System Plan (DSP) and the expenditures proposed in the 2028-2032 capital plan.

The process is informed by the detailed evidence presented within the DSP:

- Section 3.2 describes asset condition, demographics, performance and lifecycle strategies;
- Section 3.3 summarizes benchmarking and independent technical studies;
- Section 3.4 assesses DER connections and distribution-system capability;
- Section 3.5 sets out DSP historical performance and performance targets; and
- Section 3.6 addresses additional planning considerations including demand scenarios, electrification, NWS, resilience and other system-planning factors.

This Section explains how those inputs are translated into investment candidates, prioritized and paced. DSP Section 3.8 presents the resulting capital plan, DSP Section 3.9 explains historical expenditure variances, DSP Section 3.10 describes execution capability, and the Investment Summary Documents (ISDs) in DSP Section 3.11 provide the project- and program-level justification.

The key elements of the Distribution System Planning process are illustrated in Figure 1. The process begins with strategy and context and a current-state assessment, proceeds through need identification and candidate development, and then applies risk assessment, calibration, prioritization, optimization, customer and enterprise engagement, and pacing before the final plan is approved.

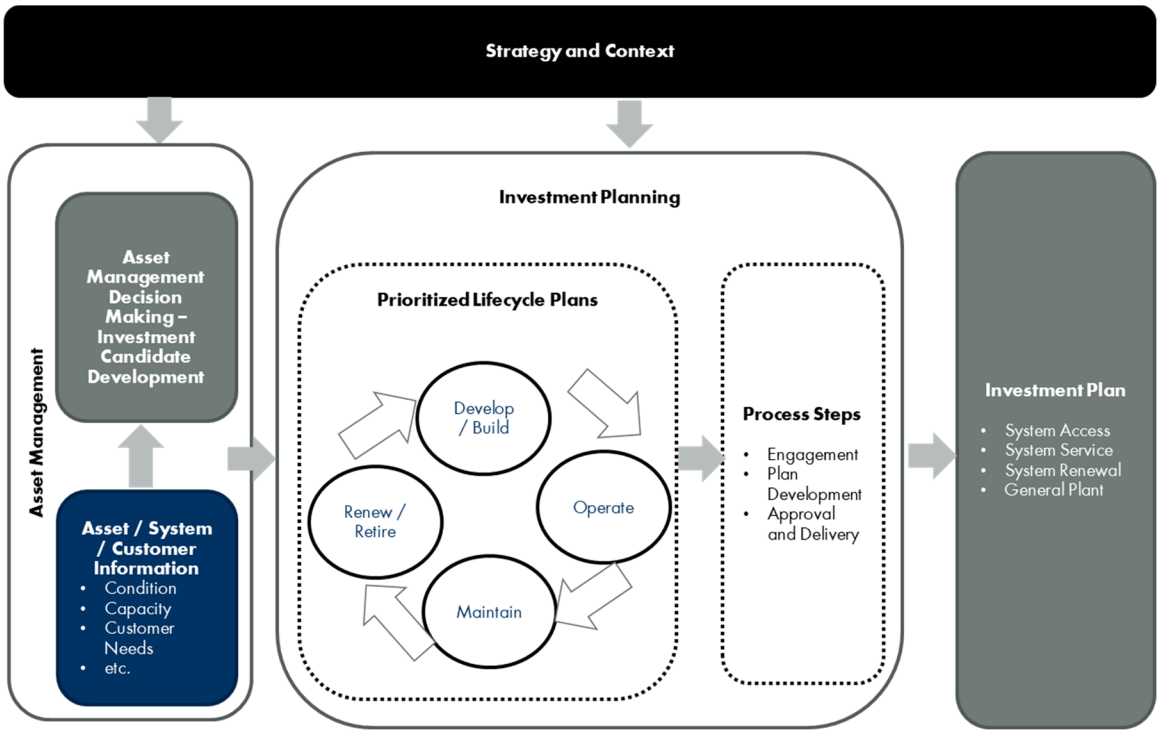


Figure 1: Distribution System Planning Process

The overall investment planning process remains materially consistent with the planning process used in support of Hydro One's 2023-2027 application (EB-2021-0110). Hydro One has, however, strengthened the information and analytical tools used to apply the framework in response to changes in system conditions and regulatory expectations.

3.7.2 STRATEGY AND PLANNING CONTEXT

Hydro One developed its DSP in response to an operating environment that differs materially from the assumptions underlying the 2023-2027 plan. Electricity demand and customer connection activity have increased, infrastructure input costs and equipment lead times have risen, reliability pressures have increased, severe weather has become more frequent and consequential, and a portion of planned renewal and reliability work was re-paced during the current period to accommodate non-discretionary demand driven and mandatory requirements. At the same time, electrification, DER adoption and evolving regulatory expectations are changing how the distribution system is planned and operated.

Hydro One's distribution system characteristics further influence the consequences of these changes, as a result of the geographically dispersed, predominantly rural and overhead system with long radial feeders, limited alternate supply in many areas and significant vegetation and weather exposure.

Taken together, these factors establish the context in which Hydro One assessed the current state of the system and developed the proposed plan. Relative to the environment assumed during development of the 2023-2027 plan, higher customer demand, increased storm activity, growing asset lifecycle pressures, and deferred renewal and reliability work have increased both the volume and urgency of investment needs requiring consideration during the 2028-2032 planning period.

3.7.2.1 HYDRO ONE DISTRIBUTION SYSTEM CONTEXT

Hydro One's distribution system serves approximately 1.5 million customers across approximately 75% of Ontario's geographic area. The system includes approximately 126,000 circuit-kilometers of distribution line, of which approximately 91% is overhead, and serves customers across urban, rural, remote and First Nations and Métis communities. Hydro One also supplies 42 partially and fully embedded distributors and has approximately 2,837 MW of DER connected to the distribution system.

Hydro One's distribution system characteristics establish an important context for the investment planning process. As described in DSP Section 3.1, subsection 3.1.2, Hydro One serves customers across a large, geographically dispersed and predominantly rural service territory and operates a system characterized by extensive overhead infrastructure, long radial and off-road feeders, multiple voltage classes, legacy configurations and specialized assets, embedded LDC supply points and significant DER penetration.

These characteristics influence both the nature of the needs Hydro One must address and how potential investment responses are developed and assessed. Depending on the location and system need, Hydro One must consider factors such as system configuration, transfer capability, access, weather and vegetation exposure, downstream customer consequences, local reliability performance, specialized asset requirements and the long-term lifecycle implications of maintaining, replacing, converting or reconfiguring existing facilities.

Accordingly, Hydro One's planning process considers both system-wide trends and location-specific system conditions when identifying and assessing investment needs. These system characteristics provide the planning lens through which the changes discussed in the following sections are evaluated and translated into Hydro One's Distribution investment priorities.

3.7.2.2 SHIFT IN LOAD PATTERNS

Section 3.3 of the Distribution System Code requires distributors to plan and develop their systems to accommodate reasonably forecast load growth. Consistent with this obligation, Hydro One must ensure sufficient capacity exists to reliably serve existing customers while accommodating future growth.

Load growth across Hydro One's service territory is increasingly driven by residential development, electrification, economic development, and large-load customers like manufacturers and greenhouses. Compared to the assumptions underlying the 2023-

2027 plan, Hydro One has experienced higher levels of customer growth and electricity demand, reflecting the combined effects of population growth, economic development, and electrification occurring across the province. Growth in customer connection requests and service upgrades has increased the need for system access and system reinforcement investments and has become an increasingly important consideration in investment prioritization decisions.

System peak demand has increased steadily since 2017, as shown in Figure 2. Looking forward, Hydro One's reference distribution peak is forecast to increase from approximately 6,903 MW in 2026 to approximately 7,453 MW in 2032, as detailed in DSP Section 3.6, subsection 3.6.2. The load growth is not uniform across the service territory: South and Central Ontario account for most of the forecast increase. As a result, Hydro One must identify where specific stations, feeders and upstream supply facilities are approaching their planning limits.

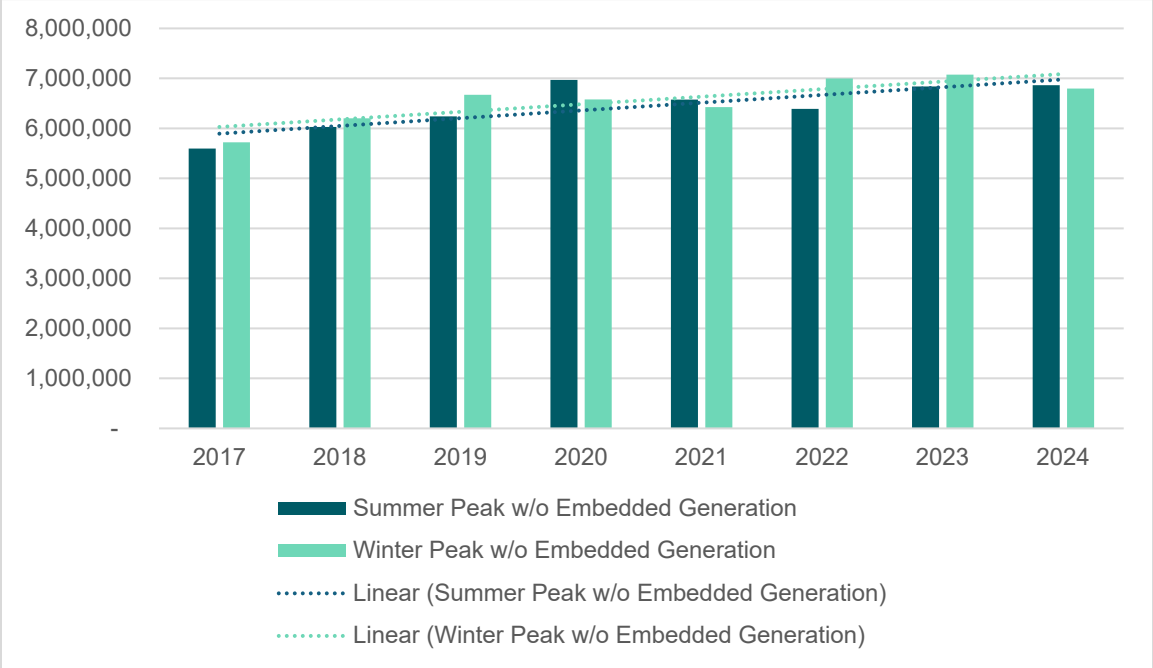


Figure 2: System Peak Load w/o Embedded Generation, kW (Source: Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.5.5 Utility Characteristics)

Electrification is also changing customer-level requirements. Hydro One's recent experience indicates that EV chargers and heat pumps are contributing to service-upgrade activity beyond what would be expected solely from growth in the number of customers, and service-upgrade volumes are expected to increase faster than new connection volumes over the 2028-2032 period. Electrification can also increase loading on service transformers and downstream distribution infrastructure. Electrification considerations are further detailed in DSP Section 3.6, subsection 3.6.4.

Growth and electrification require Hydro One to expand the system where required, but also to improve monitoring and flexibility so that traditional infrastructure is constructed at the appropriate time and can be deferred where lower-cost alternatives are available.

3.7.2.3 SHIFT IN COSTS

Since the development of Hydro One's 2023-2027 investment plan, the cost of materials, equipment, and services required to construct and maintain electricity infrastructure has increased significantly. Supply chain disruptions, inflationary pressures, geopolitical developments, labour constraints, and sustained demand for electrical infrastructure have contributed to cost escalation across key inputs, including transformers, poles, conductors, vehicles, steel, concrete, and electrical equipment.

Although Hydro One updated inflation assumptions during the current rate period proceeding (EB-2021-0110), actual cost escalation has exceeded the assumptions incorporated into the approved plan. As further discussed in SPF Section 1.8, examples of observed increases since 2020 that have affected the distribution business include:

- Power transformers: approximately 115%
- Distribution transformers (<2.5MVA): approximately 40%
- Wood poles: approximately 45%
- Wire, cable, and conductor: approximately 65%

In parallel, procurement lead times for critical electrical equipment, such as station power transformers, have increased significantly, reducing supply chain flexibility and increasing the risk of project delivery delays.

These cost pressures, together with higher-than-forecast levels of customer-driven and storm-related work, reduced the amount of discretionary work that could be delivered within approved funding levels and required Hydro One to reprioritize investments toward mandatory, customer-driven, and highest-risk activities.

3.7.2.4 SHIFT IN CLIMATE

Ontario is experiencing more frequent and severe weather events as a result of climate change. These events are creating increasing operational and financial pressures on Hydro One's distribution system.

Hydro One Distribution has experienced a sustained increase in the number of force majeure (FM) and storm days[1]. As shown in Figure 3, the recent five-year average (2020-2024) of 51.6 days, which is greater than the 10-year average (2015-2024) of 48.4 days. In 2025, there were 62 FM and storm days combined, which represents an increase of 28% over the 10-year average, resulting in higher restoration costs, increased operational complexity, and greater demands on Hydro One's workforce and emergency response capabilities. See DSP Section 3.7, Attachment 1 for a summary of all major events experienced by Hydro One between 2021 and 2025.

Weather events such as ice storms, windstorms, and other severe weather events are occurring with greater frequency and are placing increasing strain on system operations and restoration resources.

Hydro One's system configuration amplifies the customer impact of these outage drivers. On a long radial feeder, a single upstream fault can interrupt all customers downstream and limited alternate supply can prevent restoration until the fault is located, isolated and repaired. Off-road access and extensive vegetation can further increase fault exposure and restoration duration. These structural characteristics mean that reliability improvement cannot be achieved solely through replacement of failed individual assets.

[1] Hydro One defines storm days as a calendar day, with evidence of adverse weather, which results in 150 or more interruptions or more than 3% of customers interrupted.

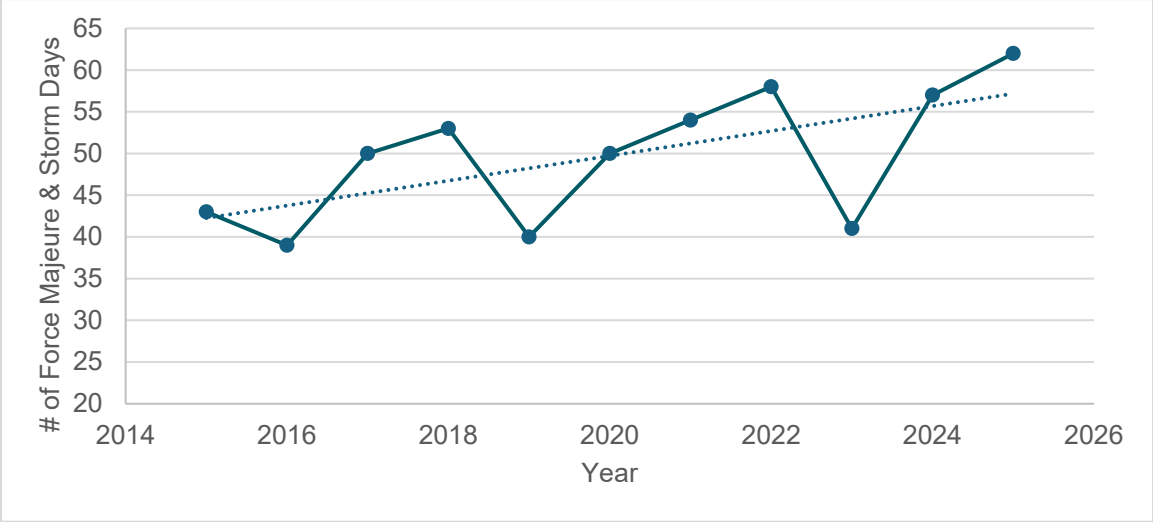


Figure 3: Storm and Force Majeure Days between 2015 and 2025

Despite representing a fraction of total days, storm events contribute to a disproportionate number of customer outages and restoration costs. For example, the May 2022 derecho and the March 2025 ice storm resulted in approximately $306M in restoration costs, more than 73 million customer interruption hours, and approximately 2.1 million customer interruptions across the two events.

Severe weather is now a significant driver of customer interruptions, accounting for approximately one-third of customer interruption frequency (SAIFI). These outages affect households, businesses, and critical community services, and their impacts are expected to increase as customer reliance on electricity continues to grow through electrification.
In addition to affecting reliability performance, severe weather has increased capital requirements associated with asset replacement, emergency restoration, and resilience improvements. As a result, Hydro One expects storm-related expenditures over the 2023-2027 period to exceed the levels anticipated during the development of the current plan (EB-2021-0110).

The trend toward more frequent and severe weather events is expected to continue throughout the planning period, reinforcing the need for continued investment in system

resilience, restoration capabilities, and risk mitigation measures. The forward-looking Climate Vulnerability Assessment and System Hardening study provides additional evidence that climate-related risk is expected to evolve over time. Using projected wind and ice-accretion conditions, the assessment identifies meaningful geographic differences in future vulnerability, with the East region showing the highest relative vulnerability and elevated vulnerability also occurring in portions of the North and Central regions. The assessment also indicates that the geographic pattern of vulnerability will change over time as climate conditions evolve. Additional details are provided in DSP Section 3.6, subsection 3.6.6.

Hydro One must address the underlying asset and vegetation causes of power interruptions, reduce the number of customers affected by faults where practical, improve isolation and restoration capability, and selectively strengthen areas where climate exposure, asset condition, system configuration and customer consequence combine to create elevated risk.

3.7.2.5 2023-2027 DEFERRALS AND REPRIORITIZATION

During the 2023-2027 period, Hydro One experienced materially higher customer- and demand-driven work, storm restoration, compliance and failure-driven requirements, together with higher material and equipment costs than contemplated when the approved plan was developed. Hydro One responded by reprioritizing capital and delivery resources toward the most immediate customer, safety, reliability and compliance requirements. As a result, the mix of work delivered during the period changed, with less planned condition-based renewal work and less reliability improvement work than originally forecast, with certain asset replacements, refurbishments, feeder ties, remote switching, and energy storage work deferred or shifted beyond the current period. Detailed expenditure and volume variances for the 2023‑2027 period are provided in DSP Section 3.9.

While this reprioritization enabled Hydro One to address immediate customer, compliance, and restoration requirements, it deferred the underlying renewal and reliability needs. As a result, portions of the identified risk and asset-condition pressures remained

unaddressed and require increased investment during the 2028-2032 period. The 2028-2032 DSP proposes to address these continuing and emerging needs at a sustainable pace while maintaining the ability to respond to mandatory and customer-driven requirements.

3.7.2.6 CUSTOMER PREFERENCES AND NEEDS

Customer preferences are an important input to Hydro One's investment planning process. Hydro One engaged Innovative Research Group ("IRG") to conduct Phase I of its application-specific customer engagement in mid-to-late 2024, before development of the 2028-2032 investment plan. Phase I was designed to identify the customers' needs and their general preferences regarding investment trade-offs so that this information could be considered at the outset of the investment planning process. Detailed results of the customer engagement are provided in SPF Section 1.6, Attachment 1.

Reasonable rates and reliable electricity were identified by customers as leading priorities. For the distribution system specifically, Phase I found that:

- A majority of customers support Hydro One making necessary investments in the distribution system to improve or maintain current levels of reliability related to the distribution grid.
- A majority of customers want Hydro One to make targeted investments to improve reliability for customers who experience significantly poorer reliability than average.
- A majority of customers want Hydro One to make investments to make the system more resilient to severe weather events as part of the ongoing replacement of old or failing equipment. A plurality of customers support Hydro One in making proactive investments to make the system more resilient to severe weather events.
- A plurality of customers support Hydro One making proactive investments to enable anticipated growth and accommodate new connections and service upgrades in a timely manner.
- A majority of customers want Hydro One to make proactive investments in technology to accommodate customer requests and improve system visibility.

These findings provided customer context for development of the 2028-2032 DSP and were considered together with the asset, system, operational and other planning information described in this Section. Phase II customer engagement, which tested specific investment trade-offs in the draft plan, is discussed later in Section 3.7.5.

3.7.2.7 RESULTING HYDRO ONE DISTRIBUTION INVESTMENT PRIORITIES

The planning considerations described above have informed Hydro One's investment priorities for the distribution system. These priorities reflect evolving customer needs, changing system conditions, and the objective of delivering long-term value while balancing affordability. These strategic priorities ultimately inform the prioritization of investments across the System Access, System Renewal, and System Service portfolios.

Maintaining the Grid

- **Maintain the safe and reliable operation of the existing distribution system.**

Hydro One’s first investment priority responds to a growing population of assets requiring lifecycle intervention and to the need to sustain the core infrastructure and capabilities upon which customers already rely. Without continued sustainment investment, Hydro One would face increasing exposure to asset failures, restoration complexity, safety risks, and higher lifecycle costs.

Maintaining the Grid focuses on addressing the highest-priority asset needs and avoiding both premature replacement and excessive costs associated with reactive work. Where an asset must be renewed, Hydro One also considers whether replacement on the existing configuration remains the appropriate lifecycle solution or whether a targeted change in configuration, monitoring or capability can address the underlying need more effectively over the long term. Where failures or damage nonetheless occur, emergency replacement and permanent restoration are required to return the existing system to safe and reliable operating condition.

Maintaining the Grid therefore preserves the system's ability to provide safe and reliable service while managing asset risk, regulatory compliance and long-term lifecycle cost.

Improving Reliability and Resiliency

- **Reduce outage impacts and improve the distribution system's ability to withstand and recover from increasingly severe operating conditions.**

Hydro One's second distribution investment priority focuses on reducing outage impacts and strengthening the system's ability to withstand and recover from severe weather. Investments in system hardening, feeder modernization, automation, energy storage, spare equipment, and targeted reliability improvements improve restoration flexibility, reduce outage frequency and duration, and enhance resilience across the distribution system.

This priority reflects both normal-course reliability needs and severe-weather resilience. Equipment deterioration, vegetation, long radial supply paths, limited alternate supply and difficult access can increase the frequency or duration of interruptions, while major weather events can affect many assets and customers simultaneously.

Hydro One's planning considers the underlying cause of reliability risk. Depending on the need, the appropriate response may involve asset renewal, changes to system configuration, improved transfer and sectionalizing capability, monitoring and automation, targeted hardening, energy storage or coordination with vegetation and maintenance activities. The objective is to reduce the likelihood and consequence of outages, limit the number of customers affected and restore service more quickly where the expected customer benefit justifies the investment.

Meeting Ontario's Growing Demand

- **Enable customer growth, electrification, and economic development while continuing to meet its obligations to connect customers safely and reliably.**

Hydro One's third distribution investment priority is to provide timely access to the distribution system and ensure that the system can accommodate forecast demand, enable electrification and DER integration, and support economic development while maintaining reliability and power quality.

This priority includes Hydro One's obligation to connect new customers and accommodate service upgrades and externally driven infrastructure requirements, as well as the forward-looking system investments required where existing stations, feeders or upstream facilities are approaching their planning limits.

3.7.3 ASSET, SYSTEM AND CUSTOMER INFORMATION

Following consideration of the strategy and planning context described in Section 3.7.2, Hydro One assesses detailed information regarding its assets, system and operations, customers, and other relevant influences to identify the specific needs to be addressed through the investment planning process.

As illustrated in Figure 1, these inputs form the Asset/System/Customer Information stage of Hydro One's Distribution investment planning process.

This section summarizes how those inputs inform the identification of needs that proceed to investment candidate development in Section 3.7.4. The information that follows summarizes how various inputs have been considered as part of the investment planning process. More detailed information on the various inputs can be found elsewhere in the DSP, per Table 1.

Table 1 - Detailed Information on Key Inputs to Planning Process

Input	Detailed Information
Asset Information (Condition, Demographics, Performance, Criticality, Utilization)	• DSP Section 3.2: Asset Information and Lifecycle Strategies • DSP Section 3.3, Attachment 2: Distribution Poles and Substations Benchmarking
Capacity	• DSP Section 3.6: Other Capital Planning Factors • DSP Section 3.3, Attachment 6: Electrification Scenario Study
Reliability	• DSP Section 3.5: Performance Measurement and Outcomes • DSP Section 3.11, ISD D-SS-04, Attachment 1 – First Nations Reliability Report – 2025
System Capability (DERs)	• DSP Section 3.4: Connecting DER Resources
Regional Planning	• SPF Section 1.2: Regional Planning
Climate Change	• DSP Section 3.3, Attachment 5 – Vulnerability Assessment and System Hardening Report • DSP Section 3.6: Other Capital Planning Factors

The information considered is grouped into four principal areas:

- Asset Information;
- System and Operational Needs;
- Customer Needs and Preferences; and
- External and Other Influences.

3.7.3.1 ASSET INFORMATION

Hydro One uses information regarding the condition, demographics and performance of its distribution assets, together with other asset-specific factors, to identify existing and emerging maintenance and renewal needs. Detailed asset information and lifecycle strategies are provided in DSP Section 3.2.

Hydro One uses physical or functional condition as a primary indicator to determine whether an asset requires intervention where reliable condition information is available. Demographic information identifies the maturity of asset populations and the rate at which additional lifecycle requirements may emerge. Asset performance provides evidence of whether deterioration or other asset issues are translating into failures, interruptions or operating limitations. Hydro One also considers factors such as obsolescence,

supportability, safety, environmental requirements and applicable asset-specific compliance obligations.

These information sources are considered together to identify the asset-related need and its expected timing. The identified need is subsequently considered together with system, customer and other information when potential investment candidates are developed.

Asset Condition

For assets where condition can be reliably and economically assessed, Hydro One uses asset-specific inspection, testing and diagnostic information to identify deterioration and deficiencies that may increase the probability of failure or impair an asset's ability to perform its intended function.

As of year-end 2025, Hydro One has material populations of assets in Poor condition. These include approximately 231 station transformers (excluding Peterborough and Orillia), or 19% of the population, approximately 99,000 poles, or 6%, and other station and line asset populations described in DSP Section 3.2. Table 2 summarizes, for selected key distribution asset classes, the proportion and quantity of each asset population assessed to be in poor condition as of year-end 2025.

Table 2 - List of Distribution Key Assets in Poor Condition

Asset	% in Poor Condition	Quantity in Poor Condition
Station Transformers	19%	231
Mobile Unit Substations	24%	8
Poles	6%	99,000
Submarine Cable	10%	1,350

As assets deteriorate, the likelihood of service interruptions, increased maintenance requirements, equipment failures, and safety concerns generally increases. Condition information helps to identify where there is significant risk and where a potential investment need may exist. The condition population changes as existing deficiencies are

addressed and additional assets deteriorate. Hydro One therefore also considers the expected emergence of additional poor condition assets over the planning period.

Asset Demographics

Hydro One monitors asset demographics and performance trends to identify asset populations experiencing elevated deterioration or failure rates. For example, Hydro One has observed elevated deterioration rates among Red Pine wood poles from specific vintages. Such findings indicate an increased likelihood of future failures and may identify a need for intervention earlier than would be suggested by age alone.

Asset demographics also provide a forward-looking indication of the maturity of Hydro One's asset populations. Assets that remain in acceptable condition may continue to operate beyond ESL, while condition, performance or other factors may require intervention before ESL is reached.

Hydro One's demographics indicate increasing lifecycle pressure across several major asset populations. For example, approximately 45% of station transformers were at or beyond ESL in 2025 and, absent replacement, this proportion is expected to increase to approximately 55% by 2032. Approximately 28% of poles were 60 years of age or older in 2025, increasing to approximately 35% by 2032 absent replacement.

Table 3 - Summary of Distribution Key Assets Demographics

Asset Component	Average Age	ESL	Population Beyond ESL, 2020	Population Beyond ESL, 2025	Population Beyond ESL by 2032, Absent Replacement
Station transformers	43 years (32 - ORZ, 58 - PRZ)	50 years	33%	45% (36% - ORZ, 87% - PRZ)	55% (45% - ORZ, 94% - PRZ)
MUS transformers	35 years	40 years	46%	48%	61%
Poles	43.7 years	60 years	23%	28%	35%
Underground cable	22 years	30 years	Unavailable	30%	43%
Retail Revenue Meters	11.28 years	15 years	0%	50%	68%

These aging trends, as shown in Table 3, indicate the potential scale and timing of future asset needs and help Hydro One anticipate where condition assessment, maintenance, refurbishment or renewal requirements are likely to increase during the planning period.

Asset Performance

Asset performance assessments identify needs arising from recurring failures, declining operational performance, or increasing customer impacts. Hydro One monitors asset failures, outage performance, maintenance history, and customer interruption data to identify assets or asset populations that are no longer meeting performance expectations and may require intervention.

Performance trends differ across the asset portfolio. For example, pole-related interruptions have increased and underground-cable interruptions have increased materially as the direct-buried cable population has aged, while targeted replacement of older station reclosers has improved recloser performance. Further details are presented in DSP Section 3.2.

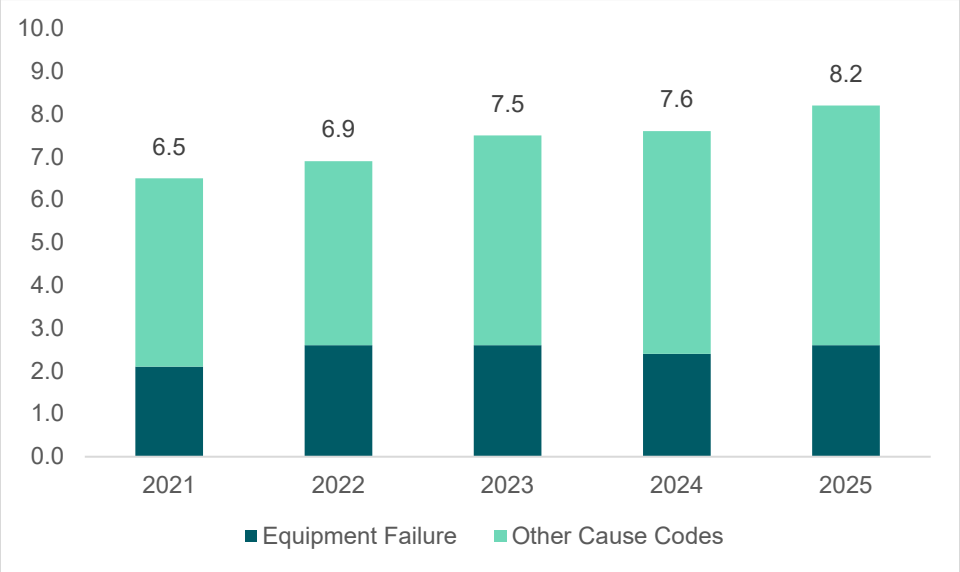


Figure 4: Portion of Annual SAIDI (Excluding Force Majeure and Loss of Supply Events) Caused by Equipment Failure

Overall, the system-level and asset-specific performance trends indicate a consistently high asset-related reliability pressure across portions of Hydro One's distribution system, as presented in Figure 4. Equipment failure remains a material contributor to customer interruptions. While distribution system reliability performance has deteriorated in recent years, equipment failures accounted for approximately one-third of annual Distribution SAIDI in recent years. The asset performance trends indicate that deterioration in several major asset populations is increasingly translating into unplanned failures and customer impacts. Together with the condition and demographic trends described above, this performance information supports increased planned renewal during the 2028-2032 period to address growing asset-related risks and reduce reliance on reactive replacement. This indicates that condition-based renewal investments continue to be an important component of maintaining and improving customer reliability outcomes.

Other Asset Factors

Hydro One also considers asset-specific factors that may create a need for intervention where conventional condition or age information is insufficient. These include functional

and technology obsolescence, safety and environmental risks, and asset-specific compliance requirements.

These considerations are particularly important where an asset remains physically operable but no longer provides the required functionality, can no longer be reasonably maintained or supported, or presents a safety, environmental or compliance issue.

Taken together, the asset information identifies which assets or asset populations require attention, the nature of the underlying issue and the expected timing and consequence of that need.

3.7.3.2 SYSTEM AND OPERATIONAL NEEDS

Hydro One also evaluates whether the distribution system has, or is forecast to have, the capacity, reliability and operational capability required to safely and reliably serve customers. These assessments identify system needs that may not be attributable to the condition of a particular asset.

The principal system and operational information considered by Hydro One includes localized capacity and regional supply requirements, system and local reliability performance, system configuration and restoration capability, and technical capability to accommodate evolving customer requirements.

System Capacity

Hydro One identifies system capacity needs through localized planning assessments, regional planning activities, and ongoing assessments of distribution system loading, available capacity, and forecast customer demand. These assessments evaluate whether existing infrastructure can reliably serve current and future customer requirements while maintaining operational flexibility. Considerations include thermal loading limits, voltage performance, short-circuit capability, regional planning, and forecast customer growth. Where demand is expected to approach available capacity, Hydro One identifies

investment needs to maintain reliability, accommodate future connections, and support continued system operation.

Capacity-related needs can manifest as thermal overloads, voltage concerns, feeder imbalance, reduced restoration capability, equipment stress, or limitations on connecting new load. These conditions may negatively affect system performance, increase reliability risk, create regulatory compliance concerns, or accelerate asset deterioration if not addressed.

As described in DSP Section 3.6, subsection 3.6.2, Hydro One's reference distribution peak is forecast to increase from approximately 6,903 MW in 2026 to 7,453 MW in 2032, an increase of approximately 550 MW or 8%. Forecast growth is not uniform across Hydro One's service territory: South and Central Ontario together account for most of the reference forecast increase through 2032.

Table 4 and Table 5 summarize station transformer and feeder overloads forecast during the 2028-2032 period, including the timing, location, and magnitude of forecast capacity constraints associated with the DSP Section 3.11, D-SS-01 System Upgrades Driven by Load Growth program.

Table 4 - Overloaded Station Transformers Regional and Annual Breakdown

Region	Year of Overload						Total Forecasted Overloaded Assets	% Overloaded Assets by Region
	Pre 2028	2028	2029	2030	2031	2032		
North	3	0	2	1	0	0	6	2.1%
Central	27	12	2	3	0	8	52	12.2%
East	15	4	4	2	1	3	29	9.0%
South	21	8	10	7	10	5	61	14.9%

Table 5 - Overloaded Feeders Regional and Annual Breakdown

Region	Year of Overload							
	Pre 2028	2028	2029	2030	2031	2032	Total Forecasted Overloaded Assets	% Overloaded Assets by Region
North	4	1	1	0	0	0	6	1.5%
Central	9	6	1	0	0	0	16	1.7%
East	13	2	8	3	1	1	28	2.8%
South	14	15	6	6	6	6	53	5.7%

Regional Planning

Hydro One Distribution actively participates in regional planning activities across 20 of Ontario's 21 planning regions. These activities identify regional supply, reliability, and capacity needs and coordinate long-term infrastructure development among the IESO, transmitters, and distributors.

Hydro One Distribution incorporates municipal input on planned load growth into the load forecasts used for Regional Planning. This input is gathered through ongoing engagement with municipal planning staff, the review of official plans, municipal or community energy plans, and direct engagement with municipalities during regional planning load forecast stages.

As detailed in SPF Section 1.2, several regions, including Windsor-Essex, London Area, and Burlington-to-Nanticoke, are experiencing significant growth that is creating capacity constraints. In Table 6, Hydro One Distribution lists the capital contribution investments aligned with Regional Planning recommendations, on-going Regional Planning activities, emerging transmission capacity needs, and distribution system needs.

Table 6 - Alignment between Distribution Capital Contribution Investments and Regional Planning

Planning Region	Investment Name	Regional Planning Alignment
Burlington to Nanticoke	New DESN at Middleport TS Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
	New DESN at Nebo TS Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
East Lake Superior	Chapleau DS #2 Upgrade – Capital Contribution	Emerging capacity need
Greater Bruce/Huron	New Maple Grove HVDS Dx to Tx Capital Contribution	Emerging capacity need
Greater Ottawa	L2M 8 km Upgrade Dx to Tx Contribution	Investment has been recommended through Regional Planning
GTA East	New Enfield TS #2 – Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
GTA North	Northern York Region TS Capital Contribution	Investment has been recommended through Regional Planning
GTA North/GTA West	Kleinburg TS Addition of T3 T4 & 2 breakers – DX CC	Capacity Constraints have been identified through the ongoing Regional Planning process
Kitchener Waterloo Cambridge Guelph	New Puslinch Station Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process. Hydro One proposed an HVDS solution in advance of the IRRP recommendation and will continue to work with the IESO on the recommended option while monitoring load trends
London Area	Yarmouth Yards DESN Tx Lines	Capacity Constraints have been identified through the ongoing Regional Planning process
	Tillsonburg TS: 230kV Line Conversion Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
	New Yarmouth Center DESN Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
	Tillsonburg TS: 230kV Station Conversion - CC	Capacity Constraints have been identified through the ongoing Regional Planning process

Planning Region	Investment Name	Regional Planning Alignment
Niagara	New Pelham HVDS Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
Northwest	Crilly DS Refurbish Dx Contribution to Tx	Capacity Constraints have been identified through the ongoing Regional Planning process
	White River DS Third Transformer Installation – Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
Peterborough Kingston	Napanee TS Upgrade Dx to Tx Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
South Georgina Bay Muskoka	Waubaushene TS: Replace T5 T6 DESN Rebuild -Dx Contribution	Investment has been recommended through Regional Planning
St. Lawrence	Brockville New TS – Capital Contribution	Capacity Constraints have been identified through the ongoing Regional Planning process
Windsor-Essex	Coatsworth Line Capital Contribution	Investment has been recommended through Regional Planning
	Leamington Area DESN5 and DESN6 Capital Contribution	Investment has been recommended through Regional Planning
	Coatsworth DESN1 & DESN2 Capital Contribution	Investment has been recommended through Regional Planning
	Lauzon TS DESN2 Capital Contribution	Investment has been recommended through Regional Planning

Reliability Needs Assessment

Hydro One monitors reliability performance through analysis of outage trends, asset performance, restoration capability, system topology, and customer impacts. These assessments identify areas where customers are exposed to recurring interruptions, extended restoration times, limited operational flexibility, or elevated vegetation and severe weather risk.

These reliability needs are increasingly influenced by severe weather, vegetation-related outages, and the operational characteristics of Hydro One's predominantly radial distribution system. As discussed in DSP Section 3.5, weather-related interruptions now

account for approximately one-quarter of customer interruption hours, while long rural feeders and remote service territories can prolong restoration efforts and increase customer outage impacts. See DSP Section 3.7, Attachment 2, for a summary of interruptions by cause code experienced by Hydro One between 2021 and 2025.

Hydro One addresses identified reliability needs through a combination of asset renewal, enhanced system visibility, grid modernization, and targeted reliability investments. Together, these investments help reduce outage frequency and duration, improve restoration performance, and strengthen the long-term resilience of the distribution system.

The foundation of this approach is sustained investment in asset renewal and vegetation management. These programs address reliability risks before they result in equipment failures or customer interruptions and help maintain the long-term health and performance of the distribution system.

Building on this foundation, Hydro One continues to invest in technologies that improve system visibility and support more informed operational and asset management decisions. These investments include station monitoring, virtual asset creation, AMI 2.0, Intelligent Grid initiatives, and real-time station and feeder monitoring. Enhanced visibility enables Hydro One to detect deteriorating equipment, vegetation encroachments, power quality issues, abnormal operating conditions, and emerging system constraints earlier than would otherwise be possible. By identifying emerging risks and deteriorating conditions earlier, these investments improve maintenance prioritization and support proactive operational planning to manage asset performance.

Foundational asset management and enhanced system visibility are further complemented by targeted reliability investments designed to address specific local reliability challenges. These investments include sectionalization and automation, clustered hardening, tie-lines and feeder interconnections, and energy storage solutions.

Together, these investments form a coordinated approach to reliability that addresses both the causes and consequences of customer interruptions. By combining asset renewal, system visibility, operational flexibility, and targeted reliability improvements, Hydro One seeks to improve customer outcomes and strengthen the distribution system's ability to withstand and recover from evolving operating and climate-related challenges.

Local Area Reliability and Operational Needs

Hydro One also assesses the local characteristics that affect the consequence and duration of customer interruptions. Long radial feeders limited alternate supply, off-road access, vegetation exposure and lengthy patrol requirements can result in customer impacts that are not fully reflected in system averages.

For example, Hydro One has more than 24,000 line-kilometers on feeders longer than 100 kilometers, and approximately 400 feeders have a significant proportion of off-road plant. These characteristics can increase fault exposure, restoration complexity and outage duration. DSP Section 3.1, subsection 3.1.2, provides further details regarding Hydro One's system configuration and its planning implications.

Hydro One therefore considers feeder-level performance, topology, alternate-supply capability, access, restoration duration, customer exposure and other local operating conditions to identify areas where existing system configuration or operating capability contributes materially to poor customer outcomes.

The output of this assessment is the specific reliability or operational limitation to be addressed – for example, excessive customer exposure to a single fault, limited ability to isolate a fault or restore load, or persistently poor local reliability – rather than a predetermined technology or investment solution.

System Capability Assessment

Hydro One assesses whether the distribution system has the technical and operational capability required to accommodate changing customer use of the grid, including increasing DER penetration and bidirectional power flow.

At the end of 2025, Hydro One had connected more than 20,000 DERs representing approximately 2,837 MW of capacity. Local thermal, short-circuit, protection, voltage and other technical limitations can restrict additional connections even where sufficient capacity exists at the broader system level. DSP Section 3.4 identifies 75 feeders unable to accommodate additional DER and a further 130 feeders that had reached their limit for additional micro-embedded generation as of year-end 2025.

Hydro One also considers the information and operating capability required to understand actual loading, available capacity and system conditions. There is a need to create these capabilities where existing information, monitoring or control is insufficient to reliably assess or operate the system under evolving requirements.

3.7.3.3 CUSTOMER NEEDS AND PREFERENCES

Customer and third-party information provides an important input to Hydro One's identification and timing of distribution needs. While the broad customer outcome preferences that informed development of the DSP are described in Section 3.7.2, Hydro One also obtains more specific information regarding actual and expected customer and third-party requirements through connection requests, ongoing customer engagement, regional and municipal coordination, and consultation with entities that use or affect Hydro One's distribution infrastructure.

Customer Needs and Information

The broad customer outcome preferences identified through Phase I engagement are described in Section 3.7.2. Customer information considered at this stage of the planning process is more specific and includes actual and expected customer requirements that may create or refine an asset or system need.

This information includes new connection and service upgrade requests, DER connection applications, customer growth plans, reliability and power quality concerns, and other customer-specific requirements. Hydro One also receives information through ongoing engagement with large distribution customers, embedded distributors, Indigenous communities and other customers whose requirements may materially affect system planning, as described in SPF Section 1.6.

Hydro One also considers the downstream consequences associated with embedded LDC supply. A Hydro One delivery point may represent one metered account while supplying a much larger population of downstream customers. Planning assessments therefore consider the customers and load dependent on the Hydro One facilities.

Customer information can establish a new need, confirm or accelerate the timing of a forecast system requirement, or change the consequence assigned to an existing asset or system issue. It is considered together with asset and system information before investment candidates are developed.

Consultation with Telecommunication Entities

Hydro One regularly engages with telecommunications entities that share or require access to its distribution infrastructure. Hydro One currently has 159 joint-use agreements with telecommunications partners governing the shared use of utility assets. These ongoing relationships provide Hydro One with information regarding planned telecommunications activity that may affect its distribution system and allow the parties to coordinate infrastructure planning where practical.

As part of this engagement, Hydro One provides relevant information to telecommunications entities, including design and attachment requirements, pole-loading tools, pole-defect information and planned pole replacements. Telecommunications entities, in turn, provide information regarding anticipated projects, permit applications and timing. In 2025, Hydro One conducted more than 100 meetings with telecommunications entities, principally in connection with activities under the *Building Broadband Faster Act*.

These discussions provided Hydro One with information regarding expected permit volumes and timing and supported identification of opportunities to coordinate telecommunications work with planned Hydro One capital and sustainment activities.

Information obtained through this consultation informs the expected volume, location and timing of third-party joint-use requirements considered in Hydro One's investment planning process. The 2028-2032 forecast for third-party joint-use work within DSP Section 3.11, D-SA-01, Joint Use and Relocations, reflects this engagement and Hydro One's current expectation that non-government-funded telecommunications submissions will remain relatively stable.

For in-year work, Hydro One engages with telecommunications partners through two primary channels:

- Large Capital Projects – Once it is confirmed that telecommunications partners may be impacted, the local operations team can be engaged to facilitate discussions on effective coordination.
- Conflict/Coordination Process - If a telecommunication partner’s application conflicts with a known project or program work area, Hydro One representatives will contact the appropriate individuals to understand project scope and timelines, then work to coordinate with the affected stakeholders accordingly.

3.7.3.4 EXTERNAL AND OTHER INFLUENCES

Hydro One's identification and assessment of distribution needs is also informed by regulatory requirements, public policy and independent studies that may create specific obligations, provide additional forward-looking information, or affect how potential responses should be evaluated.

These influences supplement the asset, system and customer information described above. Hydro One considers how they translate into a specific obligation, risk, system requirement or planning consideration.

Legislative, Regulatory and Policy Requirements

Policy, regulatory, and legislative developments are important inputs to Hydro One's planning process because they establish compliance obligations, planning expectations, and future system objectives. Hydro One monitors evolving regulatory requirements and government policy to identify needs associated with grid modernization, resilience, DER integration, electrification, customer service, and reliability. Recent initiatives, including the OEB's Framework for Energy Innovation, the Non-Wires Solutions Guideline, the Vulnerability Assessment and System Hardening Framework, Ontario's Affordable Energy Future, and Ontario's Integrated Energy Plan, continue to inform Hydro One's planning approach and investment priorities.

Hydro One's distribution capital plan for 2028-2032 is driven by a layered framework of legislative and regulatory mandates that collectively account for approximately 45% of the utility's total expenditure.

While Hydro One evaluates all investments through a consistent risk-informed planning framework, a significant portion of the proposed distribution capital plan is driven by customer, legislative, regulatory, and operational obligations that materially constrain the range of available investment alternatives. These investments must be undertaken to satisfy statutory, regulatory, customer-service, or operational requirements, although Hydro One may retain discretion regarding their timing, scope, or delivery approach in certain circumstances.

For example, the *Building Broadband Faster Act, 2021* introduced an entirely new $150.1M program requiring distribution system modifications to enable third-party broadband access. Federal metering legislation, the OEB's Distribution System Code, and IESO Market Rules drive the $81.9M Metering Sustainment program to ensure accurate billing across approximately 1.5 million retail meters. Further obligations under Hydro One's Distribution License, the Electricity Act, the Public Service Works on Highways Act, and Ontario Regulation 22/04 require the utility to connect customers on demand, accommodate municipal relocations, and maintain safe operations.

Table 7 summarizes the categories of investments driven by legislative and regulatory mandates. Further details are provided in DSP Section 3.8, and in the relevant Investment Summary Documents, which are filed in DSP Section 3.11.

Table 7 - Hydro One investments driven by legislative and regulatory mandate

OEB Category	ISD Evidence Reference	ISD Name	ISD Description	Compliance Obligations	Aggregate 2028-32 Expenditure (net $M)
System Access	DSP Section 3.11, D-SA-01	Joint Use and Relocations	Joint use and distribution relocation expenditures which enable 3rd party access to, rearrangements and/or removal of Hydro One's distribution support structure network	Hydro One's Distribution License Section 22.1, and the Public Service Works on Highways Act, and commercial agreements	$263.9M
	DSP Section 3.11, D-SA-02	New Load Connections, Upgrades and Cancellations	Connecting new or modified load customer facilities to Hydro One's distribution system, as well as disconnection of load customer facilities when circumstances warrant. 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.	Hydro One's Distribution License Section 7, and Section 28 of the Electricity Act	$1,703.3M
	DSP Section	Customer Demand	Funding for modifications to	Hydro One's Distribution	$49.7M

OEB Category	ISD Evidence Reference	ISD Name	ISD Description	Compliance Obligations	Aggregate 2028-32 Expenditure (net $M)
	3.11, D-SA-03	Distributed Energy Resources	the distribution system required to connect new Distributed Energy Resources (DER). These upgrades are necessary to prevent equipment damage and preserve power quality to existing load customers.	License, section 6.2.4.1 of the Distribution System Code.	
	DSP Section 3.11, D-SA-04	Metering Sustainment	Ensures that Hydro One has sufficient metering and communication network equipment to replace failed retail and wholesale meter installations in a timely manner for reliable customer billing; to perform required meter sampling and reverification programs; and to perform necessary upgrades and replacement of failing metering equipment	Billing Reliability standards under the OEB's Distribution System Code and Supply Service Code, as well as the Federal Electricity Gas and Inspection Act	$81.9M
	DSP Section 3.11, D-SA-05	Broadband	Joint use expenditures which enable telecom provider's access to Hydro One's support structure network	Broadband and Infrastructure Expansion Act	$150.1M
System Renewal	DSP Section 3.11, D-SR-01	Distribution Stations Demand Capital	Replacement of failing and failed station components to maintain system reliability or restore	Distribution System Code Section 7	$71.5M

OEB Category	ISD Evidence Reference	ISD Name	ISD Description	Compliance Obligations	Aggregate 2028-32 Expenditure (net $M)
			power supply to customers.		
	DSP Section 3.11, D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	Emergency replacement of distribution line 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.	Distribution System Code Section 4	$983.4M
System Service	DSP Section 3.11, D-SS-01	System Upgrades Due to Load Growth	System upgrades required to support regional load growth, from a capacity and/or voltage perspective, to ensure that the distribution system can meet current and future demand from load customers.	Distribution System Code Section 3.3 and Section 4, CSA CAN3-235	$1,377.4M
	DSP Section 3.11, D-SS-03	Demand System Modifications	This investment addresses near term system needs that arise from localized growth on the distribution system which cause equipment overload or power quality issues.	Distribution System Code Section 3.3	$117.0M
	DSP Section 3.11, D-SS-06	Power Quality and Stray Voltage	This investment involves the investigation and resolution of power quality and stray voltage issues that adversely impact	Distribution System Code Section 4, CSA CAN3-235	$37.4M

OEB Category	ISD Evidence Reference	ISD Name	ISD Description	Compliance Obligations	Aggregate 2028-32 Expenditure (net $M)
			customer experience.		

Climate Vulnerability Assessment and System hardening

As discussed in DSP Sections 3.3 and 3.6, Hydro One's Vulnerability Assessment and System Hardening (VASH) assessment provides a forward-looking view of the relative vulnerability of distribution assets and feeders to changing wind and ice-accretion conditions. The assessment identifies material geographic differences in vulnerability and indicates that the highest relative vulnerability is concentrated in the East and portions of the North and Central regions.

This information supplements historical storm and reliability data by identifying locations where future climate exposure may increase the consequence or probability of asset and system failure. VASH results are therefore considered together with asset condition, historical performance, system configuration and customer consequence when identifying needs that may warrant a resilience-focused candidate.

Non-Wires Solutions Planning Requirements

Hydro One has also integrated the consideration of Non-Wires Solutions (NWS) into its distribution planning process in accordance with the OEB's NWS Guideline for Electricity Distributors and Benefit-Cost Analysis Framework for Addressing Electricity System Needs. Once an underlying system need is identified, qualifying needs are assessed to determine whether demand reduction, load shifting, distributed resources or other non-wires measures may provide a technically viable and cost-effective alternative to conventional infrastructure.

The detailed screening, technical assessment and comparison of NWS and wires alternatives forms part of candidate development and is described in DSP Section 3.6.

Benchmarking and Independent Technical Studies

Hydro One also uses benchmarking and independent technical studies to test planning assumptions, provide external context and identify emerging considerations that should be reflected in the needs assessment or candidate-development process.

For example, the Guidehouse/First Quartile benchmarking study found that Hydro One's condition-based pole and station-transformer management practices are generally aligned with comparator practices while also identifying older asset populations, lower planned replacement rates and comparatively high station-transformer utilization. The VASH Study provides a forward-looking climate-risk perspective. The ERM electrification study examines general electrification scenarios over the 2030-2050 timeframe. The CNUC study provides information regarding vegetation-management practices and Hydro One's low-density operating environment; and the EPRI study provides information regarding the role of distribution-loss reduction in system planning. Detailed findings are provided in DSP Section 3.3.

Taken together, these external and other influences provide additional requirements, evidence and analytical frameworks that Hydro One uses to refine the needs identified from its assets, system and customers and to ensure that the subsequent candidate-development process considers relevant regulatory, technical and forward-looking information.

The collective impact of the asset, system, customer, and external information described above is reflected in a portfolio of investment needs that span asset sustainment, reliability and resilience, customer growth, system capability, and regulatory compliance.

3.7.4 INVESTMENT CANDIDATE DEVELOPMENT

Following the identification of asset, customer, system, and compliance-related needs, Hydro One develops a portfolio of investment candidates that are assessed, prioritized, and optimized through the investment planning process. These investment candidates are grouped within the OEB investment categories applicable to the DSP.

3.7.4.1 SYSTEM ACCESS

System Access investments are mandatory in nature and are system modifications that Hydro One is obligated to perform to provide and maintain customer(s) access to electricity services. These investments are mainly driven by the following triggers:

New Customer Service Requests

Investments required to connect new customers and provide service upgrades in accordance with Hydro One's obligations under the Electricity Act and the Distribution System Code.

Third-party Infrastructure Development Projects

Investments required to relocate or modify Hydro One assets to accommodate externally driven projects, including transportation, municipal, telecommunications, and other third-party infrastructure initiatives.

Mandated Service Obligations

Investments required to meet legislative, regulatory, or government-mandated obligations, including metering requirements and DER-related connection obligations.

A listing of System Access investments is included in Table 8 below:

Table 8 - System Access Investments

Program	Investment Priority	Description
D-SA-01 Joint Use and Relocations	Meeting Ontario's Growing Demand	Completes distribution modifications and relocations required to accommodate municipal, transportation, telecommunications, and other third-party infrastructure activities.
D-SA-02 New Load Connections, Service Upgrades, and Service Cancellations	Meeting Ontario's Growing Demand	Connects new customers, upgrades existing services, and removes cancelled services in response to customer-driven demand and electrification.
D-SA-03 Customer Demand Distributed Energy Resources	Meeting Ontario's Growing Demand	Connects customer-driven DER projects and completes associated system modifications and upgrades required for safe and reliable system integration.
D-SA-04 Metering Sustainment	Maintaining the Grid	Maintains retail and wholesale metering assets, communications network equipment, and metering

Program	Investment Priority	Description
		capabilities to support accurate billing, customer service, and regulatory compliance.
D-SA-05 Broadband	Meeting Ontario's Growing Demand	Completes distribution system modifications and access-related work required to accommodate broadband infrastructure development.

3.7.4.2 SYSTEM RENEWAL

System Renewal investments involve replacing and/or refurbishing system assets to extend the expected service life of the assets and thereby optimize lifecycle costs and maintain reliability performance.

System Renewal investments are developed in response to identified asset risks and condition-based needs.

Compliance

Investments are developed when changes in legislation, regulations, licences, codes, standards, or other compliance obligations necessitate modifications to Hydro One's assets, systems, or operations. Hydro One monitors applicable requirements and assesses impacts to identify investments required to maintain compliance.

Condition and Asset Failure Risk

Investments are developed where deteriorating asset condition, elevated failure risk, or increasing customer, safety, operational, environmental, or reliability consequences warrant intervention.

Obsolescence

Investments are developed when assets, equipment, or systems become obsolete, unsupported, or unable to meet operational, cybersecurity, reliability, or supportability requirements.

System Climate Resilience

Investments are developed when climate-related risks and vulnerabilities necessitate measures to improve the ability of the electricity system to withstand and recover from severe weather events. Hydro One assesses historical performance, system vulnerabilities, and projected climate impacts to identify resilience investments.

A listing of System Renewal investments is included in Table 9, below:

Table 9 - System Renewal Investments ($M)

Program	Investment Priority	Description
D-SR-01 Distribution Stations Demand Capital	Maintaining the Grid	Replaces failed or failing station assets and addresses station equipment needs required to maintain safe and reliable station operation.
D-SR-02 Mobile Unit Substation Program	Maintaining the Grid	Replaces and expands the MUS fleet to support restoration, emergency response, and planned station work while minimizing customer outages.
D-SR-03 Distribution Station Planned Component Replacement	Maintaining the Grid	Replaces deteriorated station components, including MUS structures, switches, and reclosers, to maintain safe and reliable station operation.
D-SR-04 Distribution Station Refurbishment or Replacement	Maintaining the Grid	Renews distribution stations through planned replacement, rebuilding, decommissioning, and bundled renewal work to address deteriorated and end of life components.
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response	Maintaining the Grid	Replaces and restores failed or damaged distribution assets through trouble-call and storm-response activities to restore safe and reliable service.
D-SR-07 Pole Sustainment Program	Maintaining the Grid	Addresses poor-condition poles through test-and-treat, refurbishment, replacement and targeted hardening to mitigate safety and reliability risks and improve resiliency to severe weather.
D-SR-08 Distribution Lines Minor Component Replacement	Maintaining the Grid	Replaces deteriorated or obsolete line components such as crossarms, substandard transformers, communicating fault circuit indicators, sentinel lights, and related equipment to reduce equipment failure risk.
D-SR-09 Submarine Cable Replacement Program	Maintaining the Grid	Replaces damaged, exposed or deteriorated submarine cables to mitigate safety and reliability risk.
D-SR-10 Distribution Lines Sustainment Initiatives	Improving Reliability and Resiliency	Rebuilds and relocates line sections with a high concentration of poor-condition assets to maintain or improve reliability and restoration access.
D-SR-12 Advanced Metering Infrastructure 2.0 (incl. DIDA)	Maintaining the Grid	Replaces legacy smart meters with next-generation metering and communications capability and incorporates distributed intelligence and distribution automation functionality to support improved data granularity, system visibility, outage response, customer insights, DER-related use cases, and load planning.
D-SR-13 Distribution Spare Transformer Purchase Program	Improving Reliability and Resiliency	Procures spare distribution station transformers to ensure spare-fleet adequacy, support timely replacement of failed or failing units and reduces restoration risk.
D-SR-14 Selective Undergrounding	Improving Reliability and Resiliency	Undergrounds targeted sections of vulnerable overhead infrastructure to reduce severe-weather exposure and improve reliability and resiliency.

Program	Investment Priority	Description
D-SR-15 Underground Cable Replacement Program	Maintaining the Grid	Replaces and rejuvenates aging and poor-performing underground cables to improve asset condition and reduce cable-related outages.
D-SR-16 Creation of Virtual Assets	Maintaining the Grid	Creates a digital library using LiDAR and satellite imagery to support future virtual inspections and asset-condition assessment.
D-SR-17 Voltage Consolidation	Improving Reliability and Resiliency	Converts end of life transformer stations and associated feeders from 4.16kV to a higher standard voltage to improve operational flexibility, system resiliency, and mitigate risks associated with non-standard infrastructure.

3.7.4.3 SYSTEM SERVICE

System Service investments are modifications to the distribution system to ensure that it continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements, including addressing capacity and reliability needs.

System Service investments are developed to address identified capacity, reliability, power quality, operational capability, and policy-related needs. Candidate investments are evaluated within the context of local system conditions and are designed to ensure the distribution system continues to meet evolving customer requirements while maintaining reliability and operational effectiveness. The candidate investments are typically driven by the following triggers:

Capacity

Investments required where existing infrastructure is forecast to exceed planning or operating limits due to customer growth, electrification, or changing demand patterns.

Reliability

Investments required to reduce customer interruption frequency, duration, or consequence and improve system resilience.

Power Quality

Investments required to address voltage, harmonics, flicker, stray voltage, or other power quality concerns.

Public Policy Responsiveness

Investments required to support government policy objectives, regulatory direction, or public-interest initiatives.

A listing of System Service investments is included in Table 10, below:

Table 10 - System Service Investments

Program	Investment Priority	Description
D-SS-01 System Upgrades Driven by Load Growth	Meeting Ontario's Growing Demand	Constructs and upgrades stations and feeders, and other system infrastructure to relieve regional capacity, thermal, voltage, and operating constraints associated with load growth.
D-SS-02 Reliability Improvements	Improving Reliability and Resiliency	Constructs and enhances feeder ties and reduces feeder exposure to improve reliability, load-transfer capability, and alternate supply arrangements.
D-SS-03 Demand System Modifications	Meeting Ontario's Growing Demand	Completes customer and demand-driven system modifications and upgrades to address localized capacity, power quality, and equipment limitations.
D-SS-04 Energy Storage Solutions	Improving Reliability and Resiliency	Deploys grid-scale and residential battery solutions to improve reliability outcomes for vulnerable customers, First Nations communities, and rural or remote areas with poor reliability performance.
D-SS-05 Distribution Automation and Sectionalization Program	Improving Reliability and Resiliency	Installs remotely operable SCADA-enabled devices on targeted feeders to reduce outage duration and improve monitoring, switching, and restoration capabilities.
D-SS-06 Power Quality and Stray Voltage	Improving Reliability and Resiliency	Addresses customer-specific power quality and stray voltage issues to maintain safe and acceptable system performance.
D-SS-07 DER Hosting Capacity	Meeting Ontario's Growing Demand	Removes feeder constraints that limit micro-embedded generation connections to improve hosting capacity and support the safe and reliable integration of distributed resources.
D-SS-08 System Monitoring	Maintaining the Grid	Deploys online continuous asset-condition monitoring on at-risk stations transformers to enable earlier identification of deterioration and corrective action and

Program	Investment Priority	Description
		reduce the risk of unplanned failures and customer interruptions.
D-SS-09 Intelligent Grid Platform	Meeting Ontario's Growing Demand	Establishes the technology and operational capabilities required to improve real-time visibility, system control, incident management, and DER integration.
D-SS-10 Real Time Station and Feeder Monitoring	Meeting Ontario's Growing Demand	Installs monitoring devices on station transformers and feeders to improve real-time loading visibility and support system planning and operation.

3.7.5 INVESTMENT PLANNING PROCESS

Following development of the investment candidates described in Section 3.7.4, Hydro One applies its investment planning process to assess, prioritize and optimize the candidate portfolio and develop the proposed investment plan. The enterprise-wide investment planning framework is described in detail in SPF Section 1.7. This Section describes how that framework was applied to the Distribution portfolio and the development of the 2028-2032 DSP.

As illustrated in Figure 1, the investment planning stage includes two broad components. The Prioritized Lifecycle Plans component encompasses the assessment, prioritization and optimization of candidate investments and the trade-offs used to develop a draft investment portfolio. For purposes of the DSP, this process applies to the full Distribution candidate portfolio, including lifecycle renewal, capacity, reliability, customer-driven and mandated investments, rather than only lifecycle-driven investments. The Process Steps component encompasses enterprise and customer engagement, subsequent plan refinement and approval.

Hydro One uses a structured process to determine which needs should be addressed during 2028-2032, the appropriate timing and scope of intervention, and the level of residual risk that can reasonably remain, considering mandatory requirements, customer and system outcomes, affordability and execution considerations.

3.7.5.1 CANDIDATE ASSESSMENT, PRIORITIZATION AND DRAFT PORTFOLIO DEVELOPMENT

Candidate Lifecycle Risk Assessment and Calibration

Candidate investments are assessed using Hydro One's risk-based investment planning framework. As described in SPF Section 1.7, subsection 1.7.4.1, the assessment considers the safety, reliability and environmental risks that an investment is intended to mitigate and evaluates both the probability and consequence of the relevant adverse event. The assessment compares the baseline risk without the investment with the residual risk expected following the investment, providing a consistent basis for estimating the risk mitigated by each candidate.

The information developed through Sections 3.7.3 and 3.7.4 provides the fact base for these assessments. Asset condition, performance and utilization inform the probability of an adverse event, while asset criticality, customers affected and other system consequences inform the consequence assessment. System, customer and external information is incorporated where it is relevant to the risk being assessed.

Hydro One also applies flags to identify considerations that are not fully captured through the quantitative risk framework. In particular, mandatory flags identify investments where Hydro One must address the underlying requirement and a "do nothing" alternative would not satisfy the applicable obligation. These include, as applicable, immediate risks, near-term compliance requirements, customer or third-party requirements, contractual obligations and investments already in flight. Detailed definitions and treatment of mandatory investments are provided in SPF Section 1.7, subsection 1.7.4.1.1 and 1.7.4.1.2.

A mandatory designation recognizes that the underlying need must be addressed, while Hydro One continues to assess the appropriate timing, scope and delivery approach where discretion remains.

Following the initial risk assessments, cross-functional calibration sessions are conducted to improve consistency in the assumptions, information and scoring methodologies applied across investment candidates. Investment owners may revise assessments based on the results of the calibration process. Further details are provided in SPF Section 1.7, subsection 1.7.4.2.

Prioritization and Optimization

Following calibration, Hydro One uses the assessed risk mitigation and estimated investment cost to support prioritization of the candidate portfolio. Total risk mitigated reflects the reduction in applicable safety, reliability and environmental risks, while Risk Spend Efficiency (RSE) measures risk mitigated relative to the cost of the investment. Together, these measures allow candidates to be compared on a consistent basis and provide an initial indication of where investment can provide greater risk reduction per dollar.

RSE is an important prioritization tool but is not the sole determinant of the portfolio. Hydro One also considers the absolute level of risk, mandatory requirements and other considerations that may not be fully represented through the quantitative risk score. This is particularly relevant to the Distribution portfolio, where a material portion of work is responsive to customer connection requirements, third-party activities, regional and local system needs and other obligations whose timing may be externally driven. SPF Section 1.7 describes the treatment of these investments in further detail.

The prioritization process therefore provides an initial risk-informed ordering of investment candidates while preserving the ability to consider the specific nature, timing and consequences of each need before the funded portfolio is established.

Challenge Sessions, Trade-offs and Draft Plan Development

The prioritized portfolio is subsequently reviewed through structured challenge sessions. As described in SPF Section 1.7, subsection 1.7.4.4, these sessions provide a fact-based forum to review the integrated portfolio, confirm non-risk considerations and evaluate

investments around the funding margin. The sessions also provide an opportunity to test whether the proposed scope and timing remain appropriate when investments are considered collectively rather than individually.

Trade-off decisions consider both risk mitigation and RSE, together with absolute risk exposure, mandatory and other flagged considerations, strategic alignment and the consequences of deferring or re-pacing an investment. This allows Hydro One to determine where residual risk can reasonably remain and where an identified need should be addressed within the 2028‑2032 period.

The result of the prioritization, optimization and challenge process is a draft Distribution investment plan representing Hydro One's preliminary assessment of the appropriate portfolio and pacing of investment having regard to the identified asset, system and customer needs and the Distribution investment priorities described in Section 3.7.2.

This draft portfolio then proceeds through the engagement and refinement process described below.

3.7.5.2 PLAN ENGAGEMENT, REFINEMENT AND APPROVAL

Following the development of the draft portfolio of investments, Hydro One subjects the plan to additional review and engagement before final approval. As illustrated in Figure 1, these process steps include internal enterprise engagement and external customer engagement, followed by incorporation of updated planning, cost and execution information and final plan approval.

The overall timing of these activities is described in SPF Section 1.7, subsection 1.7.2.4. Phase I customer engagement was completed before development of the draft plan. The draft portfolio was developed during 2025, and enterprise engagement was undertaken before Phase II customer engagement. The final plan was subsequently refined and approved in 2026.

Enterprise Engagement

Enterprise engagement provides a further review of the draft portfolio by the lines of business responsible for delivering the work. The objective is to ensure that the portfolio remains current and executable when considered against available resources, outage requirements, material and equipment availability and project readiness.

As described in SPF Section 1.7, subsection 1.7.5.5.1, candidate investments are updated during this process to reflect current cost forecasts, schedules and scope. Enterprise engagement can also identify emerging execution or asset-management risks that require changes to the timing or definition of individual investments.

This review provides an important additional challenge to test the deliverability of the portfolio and informs the pacing of investments before the plan is finalized.

Customer Engagement

Following development and enterprise review of the draft investment plan, Hydro One conducted Phase II customer engagement to obtain customer feedback on specific investment trade-offs.

Three investment scenarios were presented during Phase II. The scenarios reflected alternative investment levels and corresponding trade-offs between near-term affordability and long-term customer and system outcomes. Customers were provided with information regarding expected bill impacts and the resulting differences in reliability, resilience, and asset condition outcomes.

Table 11 - Distribution Investment Scenarios Presented to Customers during Phase II

Segment	Option	Scenario 1 - Slower (Spend Less)	Scenario 2 - (Draft Plan)	Scenario 3 - Accelerated Pace (Spend More)
Distribution 	**Overall Distribution Reliability**	Maintains current day-to-day reliability by addressing only a limited share of known defects and poor-condition equipment, increasing the risk of future outages and unplanned repairs.	Improves day-to-day reliability by 2032 through a balanced program addressing overhead line defects, station transformers, underground cables, and targeted pole refurbishments.	Further reduces the risk of outages by accelerating repairs and replacements across overhead lines, stations, and underground assets, with higher near-term cost impacts.
	Severe Weather Resilience	Maintains the current risk of weather-related outages and longer restoration times due to limited reinforcement, vegetation management, and automation.	Reduces outage risk and shortens restoration times through targeted line hardening, increased vegetation clearing, and expanded deployment of automated switches.	Further reduces the frequency and duration of severe-weather outages by accelerating hardening, vegetation management, and automation investments.
	Targeted Reliability (Batteries)	Improves reliability for a limited number of customers in the poorest-performing areas.	Improves reliability for over 10,000 customers through a balanced deployment of community-scale and individual customer batteries.	Extends targeted reliability improvements to a larger number of customers and communities with the highest outage impacts.

Phase II of customer engagement provided customers with an opportunity to indicate their preferred balance between affordability, reliability, resilience, and long-term asset sustainability. Across the key distribution investment categories, a majority or near majority of customers supported the Draft Plan level of spending. Customers generally supported investments to maintain reliability, improve resilience to severe weather, and provide

targeted reliability improvements for customers experiencing the poorest service levels. Customer feedback also indicated support for proactive investments that enable customer growth, modernization, and improved system visibility.

In general, customer preferences aligned most closely with the Draft Plan scenario, although some customer groups expressed support for higher and lower levels of investment. Customer feedback provided important validation of Hydro One's proposed investment pace and overall capital envelope. While some customers expressed support for accelerated investment in specific areas, customers also consistently identified affordability as an important consideration.

This input ultimately informed the investment plan, as summarized in

Table 2 below:

Table 12 - Reflection of Customer Feedback into the DSP

Objective	Customer Input	How it Appears in the Plan
Connections and Growth	Requirements for timely access and grid service Proactive investment to enable anticipated growth and accommodate new connections and service upgrades in a timely manner	• Provide customers with timely access to the network through customer connection (D-SA-02) • Build out the network to enable growth (D-SS-01)
Overall System Reliability	Improve day-to-day reliability by 2032 through a balanced program addressing overhead line defects, station transformers, underground cables, and targeted pole refurbishments.	• Replace poor condition station transformers (D-SR-04) • Replace and rejuvenate underground cable (D-SR-15). • Address priority line defects (E-03-02)
Manage the Impacts of Severe Weather	Reduce outage risk and shorten restoration times through targeted line hardening, increased vegetation	• Selectively strengthen vulnerable pole clusters with higher-class poles (D-SR-07)

Objective	Customer Input	How it Appears in the Plan
	clearing, and expanded deployment of automated switches.	• Selectively underground vulnerable, high-consequence overhead line sections (D-SR-14) • Rebuild distribution line sections and relocate off-road assets to roadside (D-SR-10) • Modernize feeders with remote operable switches and communicating fault circuit indicators (D-SS-05) • Increased vegetation management (E-03-02)
Targeted Reliability	Improve reliability for over 10,000 customers through a balanced deployment of community-scale and individual customer batteries.	• Installing Grid Scale Energy Storage Systems (D-SS-04) • Installing residential energy storage system (D-SS-04)

The resulting plan reflects the areas customers consistently identified as important, including maintaining reliability, improving resilience to severe weather, enabling growth, and supporting customers experiencing poorer reliability outcomes, while balancing affordability considerations.

Final Plan Refinement and Approval

Taken together, the proposed investments reflect Hydro One's response to a changing operating environment characterized by growing customer demand, aging infrastructure, increasing climate-related impacts, and evolving system requirements. The plan seeks to balance mandatory obligations, risk reduction, customer outcomes, and affordability while positioning the distribution system to continue providing safe, reliable, and resilient service throughout the planning period.

Witness: Alexander Jackson

Throughout plan development, Hydro One considered extensive customer feedback regarding affordability, reliability, resilience, modernization, and customer growth to complement risk-based prioritization. While affordability remained an important consideration, customers generally supported investments that maintain reliability, improve resilience to severe weather, address deteriorating assets, and accommodate future growth.

Consistent with this customer feedback, and reflecting affordability considerations and ongoing portfolio optimization, Hydro One reduced the proposed investment portfolio by approximately $1.5B relative to earlier planning assumptions through the pacing, reprioritization, or deferral of select discretionary investments. These adjustments enabled Hydro One to maintain focus on the highest-priority customer, system, and asset needs while moderating rate impacts during the 2028-2032 period.

Through this process, Hydro One has developed a Distribution System Plan that prioritizes the highest-value investments, addresses identified customer and system needs, meets mandated obligations, manages emerging risks associated with aging and deteriorating assets, electrification and climate change, and balances reliability, resilience and growth objectives with affordability considerations. The final DSP aligns with Hydro One's strategic priorities and the OEB's RRF outcomes of customer focus, operational effectiveness, public policy responsiveness, and financial performance.

The final investment plan was reviewed and approved by Hydro One's Board of Directors (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. As unforeseen asset, system and customer needs emerge, Hydro One adapts and re-evaluates its investment plan as part of a rigorous re-prioritization process as described in SPF Section 1.7.

3.7.6 INVESTMENT PLAN

The final investment plan reflects the results of Hydro One's needs assessment, investment prioritization framework, customer engagement, affordability considerations, execution planning reviews, and external benchmarking. Updates to project scope, cost estimates, schedules, maturity assessments, and customer feedback were incorporated throughout plan development and portfolio optimization. The resulting portfolio reflects Hydro One's assessment of the highest priority needs that should be addressed during the 2028-2032 period after considering asset risk, customer outcomes, affordability, execution feasibility, and regulatory obligations.

Hydro One’s proposed 2028-2032 capital plan reflects a significant increase in both investment levels and the mix of work delivered relative to the 2023-2027 period. That change is driven by identifiable system needs, including continued mandatory and customer-driven work in System Access; asset condition, safety, reliability, restoration, and resiliency needs in System Renewal; and increased capacity, reliability, resiliency, DER integration, monitoring, and operational capability requirements in System Service.

The proposed plan is summarized below in Table 13, with highlights to follow.

Table 13 - Forecast Period Capital Investment Summary ($M)[2]

OEB Investment Category	Forecasting Period				
	2028	**2029**	**2030**	**2031**	**2032**
1. System Access	549.6	406.8	416.0	431.4	445.1
2. System Renewal (including AMI)	630.8	711.9	823.4	806.6	852.3
3. System Service	405.2	497.1	708.4	627.3	523.4
Subtotal Categories 1, 2, and 3	**1,585.7**	**1,615.8**	**1,947.8**	**1,865.2**	**1,820.8**
4. General Plant (Distribution)[3]	342.1	311.2	342.2	583.3	449.0
Total Distribution Capital	**1,927.7**	**1,927.0**	**2,290.0**	**2,448.5**	**2,269.8**
System O&M[4]	958.7				
Prepaid (Distribution)	100.5	138.2	122.5	104.6	98.5

The capital plan is described in detail in DSP Section 3.8.

[2] Figures presented in the tables may not sum to the totals shown due to rounding
[3] Details on General Plant expenditures are in GSP Section 4.8
[4]System O&M reflects total Operations, Maintenance and Administration expenses. Further information is provided in Exhibit E-03-01. Amounts for 2029-2032 will be determined based on the escalation factors identified in Exhibit A-04-03.

Witness: Alexander Jackson

Section 3.7 – Attachment 1 – Summary of Major Events (2021 - 2025)

Table 1 below outlines the summary of all major events experienced by Hydro One between 2021 and 2025, based on information reported in Hydro One's Major Event Response Reports for 2021 to 2025[1].

Table 1 - Summary of all Major Events from January 2021 – December 2025

Event Dates	Main Contributing Cause	Number of Customers Impacted	Time to Restore 90% of Interrupted Customers (Hours)
December 28 to 29, 2025	Adverse Weather - Freezing Rain/Ice Storm	239,000	44.53
July 24, 2025	Adverse Weather - Wind	158,000	43.35
June 21 to June 22, 2025	Adverse Weather - Wind	168,000	50.00
April 29, 2025	Adverse Weather - Wind	181,000	39.20
March 29 to April 6, 2025	Adverse Weather - Freezing Rain/Ice Storm	1,133,000	182.88
November 29 to 30, 2024	Adverse Weather - Wind, Snow, and Freezing Rain/Ice Storm	108,000	66.65
June 13, 2024	Adverse Weather - Wind	142,000	41.43
April 12, 2024	Adverse Weather - Wind	96,000	34.92
April 2 to 4, 2024	Adverse Weather - Wind	325,000	64.32
February 28, 2024	Adverse Weather - Wind	132,000	35.78
April 5 to 6, 2023	Adverse Weather - Wind, Snow, and Freezing Rain/Ice Storm	394,000[2]	70.27
February 22, 2023	Adverse Weather - Wind, Snow, and Freezing Rain/Ice Storm	99, 000[3]	86.00
December 23 to 28, 2022	Loss of Supply; Other (Tree Contacts and Equipment	525,000	111.23

[1] https://www.hydroone.com/abouthydroone/RegulatoryInformation/reportsandscorecards. Accessed on October 2, 2026

[2] For the April 5 to 6, 2023 event, the Major Event Response Report summary indicates approximately 359,000 customers were impacted during the Major Event Days and an additional approximately 35,000 customers during restoration through to April 8. The report uses approximately 394,000 total storm-impacted customers when calculating the 90% restoration metric.

[3] For the February 22, 2023 event, the Major Event Response Report summary indicates approximately 46,000 customers were impacted during the Major Event Days and an additional approximately 53,000 customers during restoration through to February. The report uses approximately 99,000 total storm-impacted customers when calculating the 90% restoration metric.

Event Dates	Main Contributing Cause	Number of Customers Impacted	Time to Restore 90% of Interrupted Customers (Hours)
	Failures), Snow, Freezing Rain, Wind Gusts of 80 – 110km/h		
December 15 to 18, 2022	Loss of Supply; Other (Tree Contacts and Equipment Failures), Freezing rain, Wet Snow, and Strong Wind Gusts	232,000	82.57
June 16 to 19, 2022	Other (Equipment Failures and Tree Contacts), Wind Gusts up to 80km/h	252,000	60.00
May 21 to June 1, 2022	Other (Equipment Failures and Tree Contacts), Derecho Storm with Torrential Rainfalls, Hail, Frequent Lightning, Tornados and Wind Gusts of up to 130km/h	890,100	250.77
April 14 to 16, 2022	Other (Tree Contacts and Equipment Failures), Heavy Wet Snow and High Winds up to 100km/h	213,000	61.12
December 11 to 18, 2021	Other (Tree Contacts and Equipment Failures During Windstorm), Widespread Gusts from 90 – 105km/h	761,100	149.20
September 12 to 15, 2021	Other (Tree Contact and Equipment Failure During Windstorm), Wind Gusts of 100+km/h	147,200	84.75

SECTION 3.7 – Attachment 2 – Historical Reliability Data by Cause Code (2021 - 2025)

Table 1, Table 2, and Table 3 below provide historical reliability data for years 2021 to 2025 by outage cause code. This data excludes Force Majeure (FM) events.

Table 1 - Number of Interruptions by OEB Cause Code Excluding FM (2021 – 2025)

Cause Code	2021	2022	2023	2024	2025
Adverse Environment	38	34	28	58	81
Adverse Weather	n/a	n/a	2,638	3,324	5,307
Equipment Failure	11,087	10,786	9,515	8,796	9,138
Foreign Interference	5,478	5,263	5,203	7,019	6,448
Human Element	649	706	707	207	168
Lightning	n/a	n/a	611	515	340
Loss of Supply	264	321	257	278	228
Scheduled	7,075	5,819	6,751	9,440	7,080
Tree Contacts	8,361	7,489	6,541	8,146	7,696
Unknown	2,256	2,245	2,564	2,544	2,629

Table 2 - Customer Interruptions by OEB Cause Code Excluding FM (2021 – 2025)

Cause Code	2021	2022	2023	2024	2025
Adverse Environment	2,695	6,275	2,475	3,446	3,500
Adverse Weather	n/a	n/a	254,323	400,156	504,282
Equipment Failure	1,192,007	1,300,642	1,177,719	927,649	988,397
Foreign Interference	244,092	316,817	323,811	398,923	435,643
Human Element	149,524	159,410	204,043	95,409	87,265
Lightning	n/a	n/a	30,740	49,458	43,203
Loss of Supply	898,886	1,193,630	928,264	958,859	687,665
Scheduled	541,418	506,654	666,607	672,276	621,535
Tree Contacts	797,763	783,403	645,703	838,585	868,248
Unknown	488,537	651,875	835,111	603,129	740,817

Table 3 - Customer Hours of Interruptions by OEB Cause Code Excluding FM (2021 – 2025)

Cause Code	2021	2022	2023	2024	2025
Adverse Environment	11,187	34,536	9,908	7,592	80,022
Adverse Weather	n/a	n/a	1,791,535	2,322,543	3,033,014
Equipment Failure	3,030,000	3,856,849	2,956,313	2,545,145	2,890,423
Foreign Interference	591,397	778,819	925,422	1,068,661	886,846
Human Element	219,663	250,750	255,190	46,318	32,846
Lightning	n/a	n/a	96,344	142,537	118,064
Loss of Supply	1,179,976	2,072,618	1,279,691	1,371,857	1,309,953
Scheduled	1,207,113	1,162,565	1,891,189	1,741,967	1,491,168
Tree Contacts	3,919,624	3,678,904	2,463,364	3,209,771	3,091,672
Unknown	431,896	538,392	624,547	491,660	712,080

Section 3.8 – DSP – CAPITAL EXPENDITURES AND TRENDS

3.8.1 INTRODUCTION

This Exhibit provides an overview of Hydro One's proposed 2028-2032 Distribution capital expenditure plan by OEB investment category and describes the investment priorities that underpin the plan: Maintaining the Grid, Improving Reliability and Resiliency, and Meeting Ontario's Growing Demand.

The evidence also includes an expenditure trend analysis comparing the proposed 2028-2032 capital plan with historical actual and bridge-period expenditures from the 2023-2027 rate period. Historical capital expenditure variances relative to the previous plan are addressed separately in DSP Section 3.9. Detailed program-level investment descriptions, expenditure forecasts, planned outputs, and supporting rationale are provided in DSP Section 3.11. The proposed accounting treatment for investments with project life cycles greater than one year, including the treatment of construction work in progress financing costs, is outlined in Exhibit C-08-01.

Table 1 below provides a summary of Hydro One Distribution's forecast capital expenditures by OEB investment category. The capital expenditures associated with the acquired service territories of Orillia Rate Zone (RZ) and Peterborough RZ are included in 2031 and 2032. Hydro One confirms that there are no expenditures for non-distribution activities in the capital expenditure plan.

Table 1 - Hydro One - Forecast Period Capital Investment Summary ($M)[1]

OEB Investment Category	Forecast Period					% of Portfolio
	2028	2029	2030	2031	2032	
1. System Access	549.6	406.8	416.0	431.4	445.1	**20.7%**
2. System Renewal	630.8	711.9	823.4	806.6	852.3	**35.2%**
3. System Service	405.2	497.1	708.4	627.3	523.4	**25.4%**
Subtotal Categories 1, 2, and 3	**1,585.7**	**1,615.8**	**1,947.8**	**1,865.2**	**1,820.8**	**81.3%**
4. General Plant (Distribution)[2]	342.1	311.2	342.2	583.3	449.0	**18.7%**
Total Distribution Capital	**1,927.8**	**1,927.0**	**2,290.1**	**2,448.6**	**2,269.9**	**100%**
System O&M[3]	958.7	-	-	-	-	-
Prepaid (Distribution)	100.5	138.2	122.5	104.6	98.5	-

Note: Totals and variances may not add due to rounding.

Over the 2028-2032 planning period, Hydro One plans to invest approximately $10,863.3M in Distribution capital (excluding pre-paid), or approximately $2,172.7M per year on average. As shown above, the composition of the proposed plan is led by System Renewal investments, which account for approximately 35.2% of the total plan, followed by System Service at approximately 25.4%, System Access at approximately 20.7%, and General Plant allocated to Distribution at approximately 18.7%.

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] Details on General Plant expenditures are located in GSP Section 4.8
[3] System O&M reflects total Operations, Maintenance and Administration expenses. Further information is provided in Exhibit E-03-01. Amounts for 2029-2032 will be determined based on the escalation factors identified in Exhibit A-04-03.

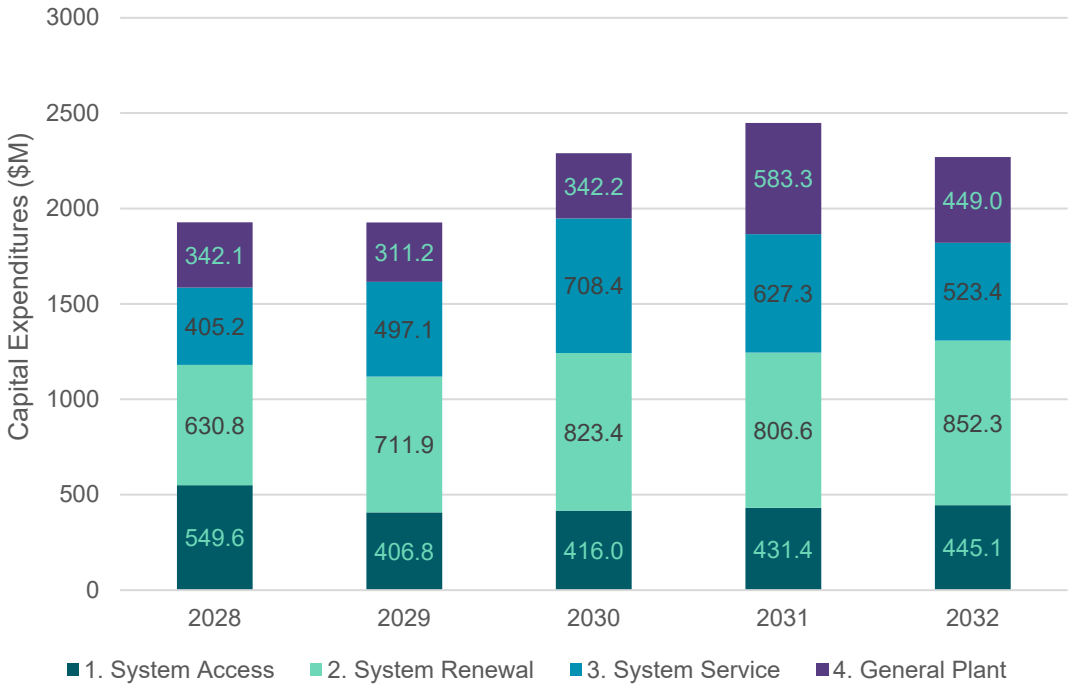


Figure 1: Forecast Period Capital Investment Summary ($M)

As outlined in DSP Section 3.7, the proposed capital plan was developed using a risk-based planning framework that integrates asset condition, system requirements, reliability performance, customer growth and service requirements, regulatory obligations, and customer feedback. Throughout this process, Hydro One refined and re-paced certain investments to balance customer priorities, system needs, execution considerations, and affordability. The resulting DSP is approximately $1.5B lower than the draft plan presented to customers during the Phase II customer engagement.

The proposed capital plan reflects a balanced approach that addresses Hydro One's obligation to connect customers, complete externally driven work, sustain aging infrastructure, improve reliability and resiliency, accommodate load growth and electrification, and enhance the operational capabilities required to manage an increasingly complex distribution system while maintaining an appropriate balance between affordability and risk. Hydro One has also attempted to streamline expenditures

for investments where feasible to minimize the impact of investment lumpiness over the 2028-2032 planning period.

Relative to the current 2023-2027 period, the scale and composition of the proposed portfolio have changed materially. During the current period, higher customer-driven, storm, compliance and other non-discretionary requirements resulted in capital and delivery resources prioritized toward the most immediate system and customer needs. This resulted in lower delivery of certain planned condition-based and reliability and resiliency work. Inflation and market cost pressures also contributed to changes in portfolio composition and impacted the ability to deliver the 2023-2027 plan. The proposed 2028-2032 plan responds to those continuing obligations while addressing broader and longer-term asset condition, resiliency, capacity, and system capability requirements that have emerged or continued to develop across the distribution system.

Based on its experience in the current rate period, Hydro One is proposing to continue or modify the Distribution Externally Driven Work Account and the Broadband Account. These accounts manage the uncertainty associated with programs where timing, scope, volume, and cost may change due to factors outside of Hydro One's control, and where Hydro One would otherwise be required to reprioritize approved investments. For further details about these accounts please refer to Exhibit G-01-03, Section 7.1 and 7.2.

3.8.2 HYDRO ONE INVESTMENT PRIORITIES

Hydro One's Distribution capital plan is organized around three investment priorities:

- **Maintaining the Grid** focuses on preserving the safe and reliable operation of the existing system. As the distribution system ages, continued investment in the replacement and refurbishment of deteriorating assets is required to mitigate the growing safety, reliability, and environmental risks associated with asset failure.
- **Improving Reliability and Resiliency** focuses on reducing outage risk and customer impacts, improving restoration capability, and strengthening the system's ability to withstand and recover from equipment failures and severe weather. These outcomes are particularly important given Hydro One's extensive rural and

radial system, long feeders, limited alternate supply capability in many areas, off-road infrastructure, and material exposure to vegetation and severe weather.

- **Meeting Ontario's Growing Demand** responds to increasing demand driven by population growth, electrification, and economic development through customer connections, targeted capacity upgrades to address localized system constraints, and investments that facilitate the connection and integration of DERs.

These three priorities provide the framework used throughout this section to explain the primary rationale and expected outcomes of the proposed capital plan.

Table 2 provides a concordance between Hydro One's investment priorities, the proposed capital programs, and the primary needs they address. For purposes of this portfolio overview, programs are assigned to the investment priority that best reflects their principal customer and system benefit, although many programs also provide secondary benefits that support other priorities. For consistency with the OEB's Filing Requirements, programs continue to be classified throughout the evidence within the applicable OEB investment categories of System Access ("SA"), System Renewal ("SR"), System Service ("SS"), and General Plant ("GP").

Table 2 - Concordance of Distribution Investment Priorities and Programs ($M)

Hydro One Investment Priority	Capital Programs	Primary Need Addressed	2028-2032 Forecast Total ($B)
Maintaining the Grid	D-SA-04, D-SR-01, D-SR-02, D-SR-03, D-SR-04, D-SR-05, D-SR-07, D-SR-08, D-SR-09, D-SR-12, D-SR-15, D-SR-16, D-SS-08	Maintaining safe and reliable service by addressing deteriorated asset condition, managing asset lifecycles, improving asset-condition monitoring, replacing/addressing failed, damaged and end of life assets, and mitigating the safety, reliability, and environmental risks associated with asset failure.	3.4
Reliability and Resiliency	D-SR-10, D-SR-13, D-SR-14, D-SR-17, D-SS-02, D-SS-04, D-SS-05, D-SS-06	Strengthening the distribution system's ability to withstand severe weather exposure, improving outage response and restoration performance, and addressing localized feeder performance issues to improve reliability and power quality.	1.6
Meeting Ontario's Growing Demand	D-SA-01, D-SA-02, D-SA-03, D-SA-05, D-SS-01, D-SS-03, D-SS-07, D-SS-09, D-SS-10	Enabling load growth and economic development through timely and cost-effective customer connections, alleviating localized capacity constraints, supporting DER integration, and facilitating externally-driven and broadband-related system access investments.	3.8

Note: Programs are assigned to the priority that best reflects their principal portfolio purpose. Several programs also support secondary priorities. Program assignments in this table are not intended to change the OEB investment category used for regulatory reporting.

3.8.2.1 MAINTAINING THE GRID

Maintaining the Grid is a core investment priority in Hydro One's 2028-2032 Distribution Capital Plan. As detailed in DSP Sections 3.2 and 3.7, Hydro One's distribution system continues to face material age and condition pressures across multiple asset classes, including aging poles and station equipment, submarine cables with identified safety and reliability risks, deteriorating underground cable assets, and metering infrastructure that must be sustained to maintain billing accuracy and regulatory compliance. Hydro One's Maintaining the Grid portfolio preserves the long-term performance of the distribution system through a balanced set of investments that address these asset lifecycle and conditions risks and support the continued provision of safe and reliable service.

As summarized in Table 3, the portfolio consists primarily of sustainment programs designed to address aging, poor condition, obsolete, failed, damaged, failing, and end of life assets, together with targeted condition-monitoring investments, across Hydro One's stations, lines, cables, metering assets, and related infrastructure.

Table 3 - Maintaining the Grid Investment Summary ($M)

Program ID	Program Name	2028-2032 Forecast Total ($M)	Program Objectives
D-SA-04	Metering Sustainment	81.9	Maintains retail and wholesale metering assets, communications network equipment, and metering capabilities to support accurate billing, customer service, and regulatory compliance.
D-SR-01	Distribution Stations Demand Capital Program	71.5	Replaces failed or failing station assets and addresses station equipment needs to maintain safe and reliable station operation.
D-SR-02	Mobile Unit Substation (MUS) Program	65.6	Replaces and expands the MUS fleet to support restoration, emergency response, and planned station work while minimizing customer outages.
D-SR-03	Distribution Station Planned Component Replacement Program	22.3	Replaces deteriorated station components, including MUS structures, switches, and reclosers, to maintain safe and reliable station operation.
D-SR-04	Distribution Station Renewal	329.1	Renews distribution stations through planned replacement, rebuilding, decommissioning, and bundled renewal work to address deteriorated and end of life components.

Program ID	Program Name	2028-2032 Forecast Total ($M)	Program Objectives
D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	983.4	Replaces and restores failed or damaged distribution assets through trouble-call and storm-response activities to restore safe and reliable service.
D-SR-07	Pole Sustainment	919.3	Addresses poor condition poles through test-and-treat, refurbishment, replacement and targeted hardening to mitigate safety and reliability risks and improve resiliency to severe weather.
D-SR-08	Distribution Lines Minor Component Replacement	131.7	Replaces deteriorated or obsolete line components such as crossarms, substandard transformers, communicating fault circuit indicators, sentinel lights, and related equipment to reduce equipment failure risk.
D-SR-09	Submarine Cable Replacement Program	126.3	Replaces damaged, exposed or deteriorated submarine cables to mitigate safety and reliability risk.
D-SR-12	Advanced Metering Infrastructure 2.0, including Distributed Intelligence and Distributed Automation	279.7	Replaces legacy smart meters with next-generation metering and communications capability and incorporates distributed intelligence and distribution automation functionality to support improved data granularity, system visibility, outage response, customer insights, DER integration, and load planning.
D-SR-15	Underground Cable Replacement Program	337.5	Replaces and rejuvenates aging and poor-performing underground cables to improve asset condition and reduce cable-related outages.
D-SR-16	Creation of Virtual Assets	38.4	Creates a digital library using LiDAR and satellite imagery to support future virtual inspections and asset-condition assessment.
D-SS-08	System Monitoring	51.2	Deploys online continuous asset-condition monitoring on at-risk stations transformers to enable earlier identification of deterioration and corrective action, and reduce the risk of unplanned failures and customer interruptions.
Total		**$3,437.9M**	

Hydro One proposes to invest approximately $3,437.9M under the Maintaining the Grid priority during the 2028-2032 rate period. Absent these investments, Hydro One would face increasing exposure to equipment failures, more complex and prolonged restoration activities, elevated safety risks, and higher lifecycle costs as the distribution asset base continues to age and deteriorate. The proposed portfolio addresses Hydro One's highest-

priority sustainment needs through a coordinated program of asset replacement, refurbishment, life-extension, condition-monitoring, and demand-driven response activities designed to maintain the safety, reliability, and performance of the distribution system throughout the forecast period and beyond.

3.8.2.2 IMPROVING RELIABILITY AND RESILIENCY

Reliability and Resiliency is the second investment priority within Hydro One's 2028-2032 Distribution Capital Plan. This priority is driven by Hydro One's operating environment, which is characterized by a large, predominantly rural service territory, extensive radial infrastructure, limited alternate supply capability, and increasing exposure to severe weather events. These characteristics increase outage risk, reduce operational flexibility during contingency events, and can prolong restoration timelines. At the same time, Hydro One continues to experience increasing weather-related impacts across its service territory. The proposed portfolio, summarized in Table 4 below, responds to these challenges through investments that strengthen physical infrastructure, improve restoration performance and operational flexibility, and reduce outage risk and the customer impacts associated with major events.

Several of the programs supporting this priority involve the replacement, rebuilding, or sustainment of existing assets and would therefore be classified as System Renewal investments for OEB reporting purposes. Within Hydro One's investment priority framework, however, these programs are included under Reliability and Resiliency because their primary customer and system benefits relate to reducing outage risk, improving restoration performance, and enhancing resiliency to severe weather, asset failures, and localized reliability challenges.

Table 4 - Reliability and Resiliency Investment Summary ($M)

Program ID	Program Name	2028-2032 Forecast Total ($M)	Program Objectives
D-SR-10	Distribution Lines Sustainment Initiatives	209.0	Rebuilds and relocates off-road line sections with high concentrations of poor condition assets to improve reliability and restoration access.
D-SR-13	Distribution Spare Transformer Purchase Program	57.5	Procures spare distribution station transformers to ensure spare-fleet adequacy, support timely replacement of failed or failing units and reduces restoration risk.
D-SR-14	Selective Undergrounding	100.3	Undergrounds targeted sections of vulnerable overhead infrastructure to reduce severe-weather exposure and improve reliability and resiliency.
D-SR-17	Voltage Consolidation	153.6	Converts end of life transformer stations and associated feeders from 4.16kV to a higher standard voltage to improve operational flexibility, system resiliency, and mitigate risks associated with non-standard infrastructure.
D-SS-02	Reliability Improvements	84.5	Constructs and enhances feeder ties and reduces feeder exposure to improve reliability, load-transfer capability, and alternate supply arrangements.
D-SS-04	Energy Storage Solutions	691.3	Deploys grid-scale and residential battery solutions to improve reliability outcomes for vulnerable customers, First Nations communities, and rural or remote areas with poor reliability performance.
D-SS-05	Distribution Automation and Sectionalization	270.8	Installs remotely operable SCADA-enabled devices on targeted feeders to reduce outage duration and improve monitoring, switching, and restoration capabilities.
D-SS-06	Power Quality and Stray Voltage	37.4	Addresses customer-specific power quality and stray voltage issues to maintain safe and acceptable system performance.
Total		**$1,604.4M**	

Hydro One proposes to invest approximately $1,604.4M over the 2028-2032 planning period to improve long-term system reliability and resiliency for customers. This portfolio reflects Hydro One's view that these outcomes are best advanced through complementary investments that enhance the distribution system’s ability to prevent, withstand, and recover from outages. Together, these programs reduce outage exposure, improve

restoration readiness, and enhance the resilience of the distribution system to severe weather, asset failures, and other high-impact outage drivers across Hydro One's service territory.

3.8.2.3 MEETING ONTARIO'S GROWING DEMAND

Meeting Ontario's Growing Demand is the largest investment priority within Hydro One's 2028-2032 Distribution Capital Plan. Continued investment in system access and capacity is required to support Ontario's growing demand for electricity, facilitate economic development and electrification, and enable customers to connect to and make greater use of the distribution system. As the licensed distributor, Hydro One has an obligation to connect customers and maintain sufficient distribution capacity to serve customer growth and evolving electricity needs. Hydro One must also respond to externally driven requirements, including municipal infrastructure projects, transportation initiatives, and broadband-related work. These investments are mandatory and necessary to enable Hydro One to meet its service obligations and support continued growth and economic development across its service territory.

Table 5 - Meeting Ontario's Growing Demand Investment Summary ($M)

Program ID	Program Name	2028-2032 Forecast Total ($M)	Program Objectives
D-SA-01	Joint Use and Relocations	263.9	Completes distribution modifications and relocations required to accommodate municipal, transportation, telecommunications, and other third-party infrastructure activities.
D-SA-02	New Load Connections, Upgrades, Cancellations	1,703.3	Connects new customers, upgrades existing services, and removes cancelled services in response to customer-driven demand and electrification.
D-SA-03	Customer Demand Distributed Energy Resources	49.7	Connects customer-driven DER projects and completes associated system modifications and upgrades required for safe and reliable system integration.

Program ID	Program Name	2028-2032 Forecast Total ($M)	Program Objectives
D-SA-05	Broadband	150.1	Completes distribution system modifications and access-related work required to accommodate broadband infrastructure development.
D-SS-01	System Upgrades Driven by Load Growth	1,377.4	Constructs and upgrades stations and feeders, and other system infrastructure to relieve regional capacity, thermal, voltage, and operating constraints associated with load growth.
D-SS-03	Demand System Modifications	117.0	Completes customer and demand-driven system modifications and upgrades to address localized capacity, power quality, and equipment limitations.
D-SS-07	DER Hosting Capacity	71.4	Removes feeder constraints that limit micro-embedded generation connections to improve hosting capacity and support the safe and reliable integration of distributed resources.
D-SS-09	Intelligent Grid Platform	31.7	Establishes the technology and operational capabilities required to improve real-time visibility, system control, incident management, and DER integration.
D-SS-10	Real-Time Distribution Station and Feeder Monitoring Program	27.7	Installs monitoring devices on station transformers and feeders to improve real-time loading visibility and support system planning and operation.
Total		**$3,792.3M**	

Hydro One proposes to invest approximately $3,792.3M over the 2028-2032 planning period in the programs supporting this priority. This portfolio reflects increasing demand for customer connections and service upgrades, capacity investments to address existing and future system constraints, investments to enable DER integration across Hydro One's service territory, and third-party driven joint use, relocation and broadband-related work. These investments are necessary to enable Hydro One to meet its service obligations, including connecting customers, maintaining sufficient system capacity, and responding

to third-party requirements. As a result, the proposed investments are largely customer- and externally driven, limiting Hydro One's discretion regarding whether the underlying work proceeds. Nonetheless, the plan reflects Hydro One's assessment of the most prudent and cost-effective means of addressing the growth needs of the system while maintaining reliable service for the utility's customers.

3.8.3 FORECAST CAPITAL EXPENDITURES AND TREND ANALYSIS

This section explains how Hydro One Distribution's proposed 2028-2032 capital expenditure forecast compares to historical and bridge-year spending during 2023-2027[4]. The purpose of this section is to explain the change in the scale and composition of the proposed capital plan. Section 3.9 separately addresses historical capital expenditure performance, including actual and bridge-period expenditures relative to previously approved or planned capital expenditure levels.

At the total Distribution capital envelope level, forecast expenditures excluding pre-paid are approximately $10,863.3M over 2028-2032, compared to approximately $5,527.7M over the 2023-2027 period, representing an increase of approximately $5,335.6M, or 96.5%. Excluding General Plant, the combined forecast expenditures for System Access, System Renewal, and System Service are approximately $8,835.4M over the 2028-2032 planning period, compared to approximately $4,805.1M over 2023-2027, representing an increase of approximately $4,030M or 83.9%. General Plant expenditures are addressed separately in GSP Section 4.8.

The forecast reflects a broader response to customer, asset, reliability, resiliency, capacity, and operational capability requirements than was possible to achieve during the 2023-2027 period with current investment levels. During that period, Hydro One prioritized mandatory, safety, reliability, compliance, and customer-driven work within the available

[4] The variances described in this Exhibit are relative to Hydro One's December 2022 capital expenditure plan, which reflects the OEB-approved capital expenditures established through the Settlement Proposal in Hydro One's 2023-2027 Distribution Rates application (EB-2021-0110). In its November 29, 2022 Decision and Order, the OEB approved the capital expenditure and in-service envelopes set out in the Settlement Proposal. In December 2022, Hydro One allocated these approved envelopes to individual programs and projects for each year of the rate period. These allocations represent the basis for the variance comparisons.

capital envelope, and certain condition-based, reliability, resiliency and system capability investments were therefore advanced at a more limited pace. The proposed plan responds to these accumulated and incremental requirements, including needs that have emerged or continued to develop across the distribution system, while enabling Hydro One to continue meeting its customer and regulatory obligations.

Across the portfolio, forecast expenditures are also influenced by inflation and material cost escalation across the key equipment and materials needed to deliver the work, consistent with the broader market pressures discussed in SPF Section 1.8. However, incremental needs for investment are the primary driver. This includes continued customer and DER growth in System Access; broader renewal, lifecycle, and system hardening requirements in System Renewal; and increased capacity, reliability, resiliency, DER, monitoring, and operational capability needs in System Service, collectively shown in Table 6 and Figure 2.

Table 6 - Total Forecast Trends Relative to Historical Spending ($M)[5]

OEB Category	2023-2027 Historical and Bridge Total	2028-2032 Forecast Total	Variance ($M)	Variance (%)
1. System Access	1,707.4	2,248.9	541.5	31.7%
2. System Renewal (Excl. AMI 2.0)	1,512.2	3,545.5	2,033.3	134.5%
3. System Renewal (AMI 2.0 Only)	546.9	279.7	-267.2	-48.9%
4. System Service	1,038.7	2,761.3	1,722.6	165.8%
Subtotal Categories 1, 2, 3 and 4	**4,805.1**	**8,835.4**	**4,030.3**	**83.9%**
5. General Plant Allocated to Distribution	722.6	2,027.9	1,305.3	180.6%
Total Distribution Capital	**5,527.7**	**10,863.3**	**5,335.6**	**96.5%**
System O&M	**3,324.0**	-	-	-

[5] Figures presented in the tables may not sum to the totals shown due to rounding.

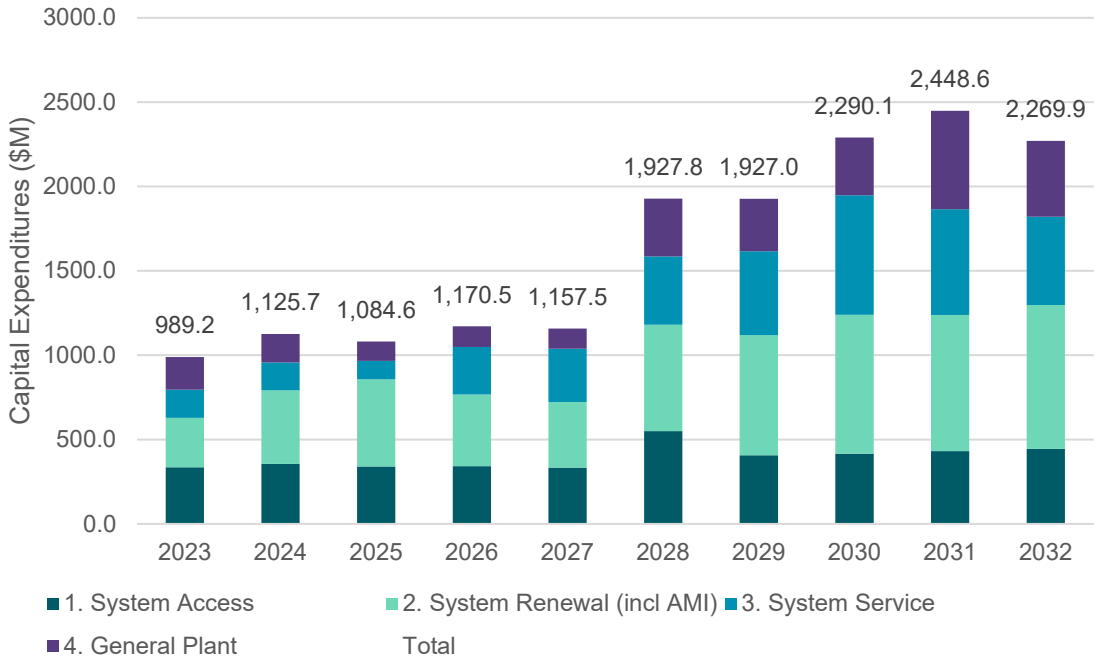


Figure 2: Ten-Year Capital Plan Snapshot

3.8.3.1 SYSTEM ACCESS

System Access expenditures represent customer and externally driven obligations for Hydro One Distribution. For the 2028-2032 planning period, System Access expenditures are forecast at $2,248.9M, compared to $1,707.4M during the 2023-2027 historical and bridge period, representing an increase of $541.5M, or 31.7%.

Relative to the 2023-2027 period, the proposed System Access portfolio reflects continued growth in customer-driven and externally driven work. The portfolio includes investments to connect new customers, accommodate service upgrades, support increasing levels of DER adoption, and respond to third-party requirements, including ongoing broadband deployment and related infrastructure activities. These increases are partially offset by lower metering expenditures following the completion of the AMI 2.0 transition.

The increase in System Access expenditures is primarily driven by customer- and externally driven work that Hydro One is obligated to undertake. This portion of the portfolio is largely non-discretionary in nature, with expenditure levels largely determined

by the volume and characteristics of customer connection requests, service upgrade requirements, DER connection activity, and third-party driven projects. The proposed portfolio reflects Hydro One's assessment of the most prudent and cost-effective means of meeting these obligations while maintaining reliable service and supporting the continued growth and evolution of the distribution system.

Table 7 provides a program-by-program breakdown of the expenditure variances, followed by a discussion of the key programs contributing to those changes.

Table 7 - System Access Program Forecast Trends Relative to Historical Spending ($M)[6]

Program	2023-2027 Historical and Bridge Total	2028-2032 Forecast Total	Variance ($M)	Variance (%)
D-SA-01 Joint Use and Relocations	229.7	263.9	34.2	14.9%
D-SA-02 New Load Connections, Service Upgrades and Service Cancellations	1,292.4	1,703.3	410.9	31.8%
D-SA-03 Customer Demand Distributed Energy Resources	14.0	49.7	35.7	255.0%
D-SA-04 Metering Sustainment	164.9	81.9	-83.0	-50.3%
D-SA-05 Broadband	-	150.1	150.1	-
D-SA-Other	6.4	-	-6.4	-100.0%
Total System Access	**1,707.4**	**2,248.9**	**541.5**	**31.7%**

The key programs driving the forecasted increase in System Access are:

- **D-SA-02 New Load Connections, Service Upgrades and Service Cancellations:** This program is the largest contributor to the proposed increase in System Access expenditures, accounting for $410.9M of the period-over-period variance. The increase is driven by higher forecast volumes of customer connection and service upgrade work, and higher costs associated with changes in design practices required to accommodate higher residential loading due to electrification. New connection volumes are forecast to increase by 6%, from 88,580 in 2023-2027 to 93,500 in 2028-2032, while service upgrade volumes are

[6] Figures presented in the tables may not sum to the totals shown due to rounding.

forecast to increase by 33%, from 29,370 to 38,900[7]. The higher service upgrade forecast reflects, in part, the growing adoption of at-home EV chargers and heat pumps, which increases residential customer loading and may require additional or higher-capacity transformers, conductors, and other distribution assets.

- **D-SA-05 Broadband:** Enabling make-ready work for broadband infrastructure build out projects accounts for $150M of the proposed increase in System Access. This program supports the ongoing mandatory make-ready work required to comply with the O. Reg. 410/22 (Electricity Infrastructure – Designated Broadband Projects), as amended by O. Reg. 248/25. During the current rate period, the associated revenue requirement impacts were recorded in the Designated Broadband Project Impacts Deferral Account as discussed in Exhibit G-01-01, Section 5.1.6, and the proposed expenditures reflect the volume of make-ready work associated with the known applications which must be completed by June 2028.
- **D-SA-03 Customer Demand Distributed Energy Resources:** This program contributes $35.7M to the period-over-period variance in System Access expenditures. The increase is driven by higher forecast DER connection activity and the associated investments required to accommodate those connections, while maintaining power quality, protection coordination, equipment integrity and system reliability. Hydro One forecasts approximately 9,890 DER connections over the 2028-2032 period, compared to approximately 5,180 connections in 2023-2027, including 8,075 renewable micro-DER and 1,425 renewable small-DER connections. The forecast is informed by historical expenditures, current DER programs and the IESO's DER Potential Study, which indicates continued growth in DER adoption and connection activity.
- **D-SA-01 Joint Use and Relocations:** Forecast expenditures increase by $34.2M relative to the 2023-2027 period. The increase is primarily driven by Relocations expenditures due to continued municipal and provincial infrastructure development requiring Hydro One assets to be relocated. This forecast reflects historical

[7] The connection and service upgrade volumes exclude Orillia RZ and Peterborough RZ from 2028 to 2030 and include them for 2031 and 2032. Total volumes for Hydro One, Orillia RZ, and Peterborough RZ are provided in DSP Section 3.11, D-SA-02.

expenditures adjusted for known scope, inflation, and integrated work volumes from acquired utilities, as well as expected demand associated with average provincial population growth of 1.0% annually and Ontario's planned $147B investment in hospitals, transit, highways, and other infrastructure.

- **D-SA-04 Metering Sustainment**: The above-noted increases are offset by a decline in Metering Sustainment of $83.0M. This decrease is driven by the elimination of the need to replace failing AMI 1.0 meters, as all are scheduled to be replaced by AMI 2.0 meters by the end of 2029. Following 2029, AMI 2.0 meters will still experience failures and require replacement, but at a much lower, steady-state rate consistent with newer assets and normal causes.

3.8.3.2 SYSTEM RENEWAL

System Renewal is Hydro One's largest distribution capital investment category for the 2028-2032 planning period. System Renewal expenditures are forecast at $3,825.1M, compared to $2,059.0M during the 2023-2027 historical and bridge period, representing an increase of $1,766.1M, or 85.8%. Excluding AMI 2.0, forecast System Renewal expenditures total $3,545.5M, compared to $1,512.2M in the prior period, representing an increase of $2,033.3M, or 134.5%.

Relative to the 2023-2027 period, the proposed System Renewal portfolio reflects a material change in both scale and composition. During the current period, Hydro One was required to prioritize investments that addressed the most immediate asset, customer, operational, and system risks within available capital and delivery constraints. As a result, a number of condition-based, reliability, restoration, and resiliency-focused investments were advanced at a more limited pace than required to fully address the underlying needs of the distribution system.

The proposed 2028-2032 portfolio reflects Hydro One's transition from managing immediate risks toward addressing a broader set of long-term asset condition, reliability, restoration, and resiliency requirements across the distribution system. Many of these needs were previously identified but could not be advanced at the same pace during the current period. The proposed investments are intended to address the continued aging of

the asset base, reduce exposure to equipment failures and service interruptions, improve restoration outcomes, and strengthen overall system resiliency.

As summarized in Table 8, the increase in System Renewal expenditures reflects both expanded investment in existing sustainment programs and increased investment in programs designed to address emerging condition, reliability, restoration, and resiliency needs across the distribution system. Table 8 provides a program-by-program breakdown of the period-over-period variances, followed by a discussion of the key programs contributing to those changes.

Table 8 - System Renewal Forecast Trends Relative to Historical Spending ($M)[8]

Program	2023-2027 Historical and Bridge Total	2028-2032 Forecast Total	Variance ($M)	Variance (%)
D-SR-01 Distribution Stations Demand Capital Program	70.2	71.5	1.3	1.9%
D-SR-02 Mobile Unit Substation Program	12.0	65.6	53.6	446.7%
D-SR-03 Distribution Station Planned Component Replacement Program	10.9	22.3	11.4	104.6%
D-SR-04 Distribution Station Renewal	28.3	329.1	300.8	1,062.9%
D-SR-05 Distribution Lines Trouble Call and Storm Damage Response Program	972.3	983.4	11.1	1.1%
D-SR-06 Distribution Lines PCB Equipment Replacement Program[9]	76.2	0.0	-76.2	-100%
D-SR-07 Pole Sustainment Program	177.7	919.3	741.6	417.3%
D-SR-08 Distribution Lines Minor Component Replacement	38.4	131.7	93.3	243.0%
D-SR-09 Submarine Cable Replacement Program	10.4	126.3	115.9	1,114.4%
D-SR-10 Distribution Lines Sustainment Initiatives	103.8	209.0	105.2	101.3%
D-SR-11 Life Cycle Optimization & Operational Efficiency Projects[10]	0.2	0.0	-0.2	-100%

[8] Figures presented in the tables may not sum to the totals shown due to rounding.
[9] D-SR-06 concludes during the 2023-2027 period and is not continued in the 2028-2032 period.
[10] The continued scope of D-SR-11 is incorporated into D-SR-04 for the 2028-2032 period.

Program	2023-2027 Historical and Bridge Total	2028-2032 Forecast Total	Variance ($M)	Variance (%)
D-SR-12 Advanced Metering Infrastructure 2.0, including Distributed Intelligence and Distributed Automation	546.9	279.7	-267.2	-48.9%
D-SR-13 Distribution Spare Transformer Purchase Program	0.6	57.5	56.9	9,483.3%
D-SR-14 Selective Undergrounding	-	100.3	100.3	-
D-SR-15 Underground Cable Replacement Program	2.6	337.5	334.9	12,880.8%
D-SR-16 Creation of Virtual Assets	-	38.4	38.4	-
D-SR-17 Voltage Consolidation	-	153.6	153.6	-
D-SR-Other	8.9	-	-8.9	-100.0%
Total System Renewal	**2,059.0**	**3,825.1**	**1,766.1**	**85.8%**

The key programs driving the forecasted increase in System Renewal are:

- **D-SR-07 Pole Sustainment:** This program is one of the largest drivers of the proposed increase in System Renewal expenditures, contributing $741.6M to the period-over-period variance. The increase reflects a level of materially higher sustainment activity necessary to manage the risk associated with a large and aging pole fleet, a growing population of poor condition poles, and increasing exposure to severe weather events, which amplify the consequences associated with deteriorated poles. Test-and-treat volumes are expected to increase from approximately 235,000 poles in 2023-2027 to 460,000 poles in 2028-2032, restoring the 15-year cycle, while pole replacement and mechanical refurbishment volumes will increase from approximately 17,200 to 86,000 poles. This work responds to approximately 99,000 identified poor condition poles and about 15,000 additional poles being identified in poor condition annually. The program is expected to contain the poor condition population at approximately 135,000 by 2032, compared with more than 200,000 without intervention.
- **D-SR-15 Underground Cable Replacement and Rejuvenation:** This is a new program contributing $334.9M to the period-over-period variance. Hydro One proposes to replace approximately 250km of deteriorated underground cable and rejuvenate approximately 500km through cable injection, focusing on aging direct-

buried cables and areas experiencing poor underground cable reliability. The forecast is driven by the aging cable population and is intended to mitigate the increasing reliability risks associated with a continued run-to-failure asset management approach. By 2032, approximately 43% of underground cables are expected to exceed their 30-year service life, while annual cable-related interruptions increased by approximately 60% during 2021-2025 compared to 2016-2020.

- **D-SR-04 Distribution Station Refurbishment or Replacement:** This program contributes $300.8M to the period-over-period variance, increasing from $28.3M in 2023-2027 to $329.1M in 2028-2032. The increase reflects a broader station renewal scope to address end of life stations, from eight material investments in 2023-2027 to 81 material projects in 2028-2032. Increased investment is required to address poor condition and aging transformer assets, mitigate the risk of customer outages associated with transformer failures, and support the continued reliable operation of the distribution system.
- **D-SR-17 Voltage Consolidations:** This is a new program contributing $153.6M to the period-over-period System Renewal variance. The program upgrades 23 end of life 4.16 kV station transformers and approximately 200 circuit kilometres of associated lines to standardized 8.32 kV or higher voltage. Coordinating conversion with planned station renewal avoids future rework and duplicative investment, while increasing load-serving capability and enabling additional feeder ties to support operational flexibility, outage restoration, future load growth, electrification, and DER integration.
- **D-SR-09 Submarine Cable Replacement:** This program contributes $115.9M to the period-over-period variance, increasing from $10.4M in 2023-2027 to $126.3M in 2028-2032. The increase is due to a larger number of damaged, exposed, and deteriorating submarine cable assets requiring planned intervention to address safety and reliability risks. The program will replace approximately 1,720 submarine cables in the 2028-2032 period compared to 105 cables in 2023-2027 and will refurbish 1,530 submarine cables compared to 432 cables in the current period.

- **D-SR-10 Distribution Lines Sustainment Initiatives:** This program contributes $105.2M to the period-over-period variance, increasing from $103.8M to $209.0M. The increase reflects higher work volumes and broader line sustainment scope, with 31 material projects planned in the 2028-2032 period compared with 10 executed in the current rate period. The program will construct more than 400km of distribution line to relocate off-road feeder sections to road allowance to improve access for inspection, maintenance and outage response and reduce future restoration times.
- **D-SR-14 Selective Undergrounding:** This is a new program contributing $100.3M to the period-over-period variance. The program undergrounds approximately 120km of vulnerable overhead infrastructure, where poor condition assets coincide with high customer consequences and significant vegetation, severe-weather or access risks.
- **D-SR-08 Distribution Lines Minor Component Replacement:** This program contributes $93.3M to the period-over-period variance, increasing from $38.4M over the 2023-2027 period to $131.7M in the proposed plan. The increase is driven by higher planned volumes of cross arm and substandard-transformer replacements and the introduction of planned CFCI replacements. Cross arm replacements increase from approximately 6,000 to 15,000, while substandard transformer replacements increase from 94 to 785. The work addresses cross arms in poor condition or expected to deteriorate by 2032 and substantially completes the replacement of identified substandard or obsolete transformers. The plan also includes the replacement of 4,350 defective, end of life, or obsolete CFCIs, including units affected by the retirement of 3G communications service.
- **D-SR-12 AMI 2.0:** The above-noted increases are partially offset by a decline in D-SR-12 AMI 2.0 expenditures of $267.2M, reflecting program phase completion and lower forecast deployment requirements as the metering asset base transitions from large-scale replacement to a steadier sustainment profile.

3.8.3.3 SYSTEM SERVICE

For the 2028-2032 planning period, System Service expenditures are forecast at $2,761.3M compared to $1,038.7M over the 2023-2027 period, representing an increase

of $1,722.6M, or approximately 165.8%. On an average annual basis, this reflects investment of approximately $552.3M per year over the upcoming rate period, compared to approximately $207.7M per year during the current rate period.

Relative to the 2023-2027 period, the proposed portfolio represents a broader response to both existing and emerging system needs. While Hydro One continued to invest in load-driven upgrades and customer-driven system modifications during the current period, reliability, resiliency, and enabling capability investments were implemented at a more limited scale or, in some cases, were not previously required. New programs such as DER Hosting Capacity and System Monitoring, together with the expansion of the Intelligent Grid Platform, will provide the capacity and operational capabilities needed to plan, operate, and manage a more electrified, DER-active, and data-intensive distribution system.

The primary driver of expenditure growth is the increased level of investment required to address evolving system needs. These include regional and localized capacity constraints, reliability and resiliency challenges, increasing DER adoption, and the growing operational complexity associated with operating a more electrified and digitally enabled distribution system. Forecast expenditures are also influenced by broader market and execution cost pressures.

As summarized in Table 9, the proposed portfolio reflects both an expansion of existing investments and the introduction of several new capability-focused programs relative to the historical period.

Table 9 - System Service Forecast Trends Relative to Historical Spending ($M)[11]

Program	2023-2027 Historical and Bridge Total	2028-2032 Forecast Total	Variance ($M)	Variance (%)
D-SS-01 System Upgrades Driven by Load Growth	666.8	1,377.4	710.6	106.6%
D-SS-02 Reliability Improvements	15.7	84.5	68.8	438.2%
D-SS-03 Demand System Modifications	118.6	117.0	-1.6	-1.3%
D-SS-04 Energy Storage Solutions	36.3	691.3	655.0	1,804.4%
D-SS-05 Distribution Automation & Sectionalization	111.0	270.8	159.8	144.0%
D-SS-06 Power Quality and Stray Voltage	45.0	37.4	-7.6	-16.9%
D-SS-07 DER Hosting Capacity	-	71.4	71.4	-
D-SS-08 System Monitoring	-	51.2	51.2	-
D-SS-09 Intelligent Grid Platform	16.7	31.7	15.0	89.8%
D-SS-10 Real-Time Distribution Station and Feeder Monitoring	-	27.7	27.7	-
Other Distribution System Service	27.4	0.8	-26.6	-97.1%
Total System Service	**1,038.7**	**2,761.3**	**1,722.6**	**165.8%**

The key programs driving the forecasted increase in System Service are:

- **D-SS-01 System Upgrades Driven by Load Growth:** As the largest contributor to the increase in System Service expenditures, this program accounts for $710.6M of the period-over-period variance. The increase is driven by sustained load growth, electrification and economic development across Hydro One's service territory, resulting in a growing number of stations and feeders that are currently constrained or forecast to become constrained by 2032. Hydro One expects to deliver 190 material load growth investments over the 2028-2032 period, including station and feeder investments, compared with 123 material investments in 2023-

[11] Figures presented in the tables may not sum to the totals shown due to rounding.

2027. The program will also include the Secondary Electrification Program. These investments are required to address capacity, thermal, voltage, and operational constraints while maintaining reliable service to customers.

- **D-SS-04 Energy Storage Solutions:** A significant portion of the forecast increase is attributable to Energy Storage Solutions, which contributes $655.0M to the period-over-period variance. The increase reflects the growing need to improve reliability and resiliency for customers in rural, remote, and First Nations communities where conventional wires solutions are not feasible. The program expands from one grid-scale project and approximately 360 residential installations in the current period to 25 grid-scale projects and 5,400 residential installations in 2028-2032. The investment is expected to provide localized backup power and improve reliability for up to 9,400 customers.
- **D-SS-05 Distribution Automation & Sectionalization:** Forecast expenditures for this program increase by $159.8M, from $111.0M in 2023-2027 to $270.8M in 2028-2032. The increase is primarily driven by expanding remote-operable device installations from approximately 400 units completed during 2023-2027 to approximately 1,150 units during 2028-2032. This expanded deployment of remotely operable SCADA-enabled devices on targeted feeders will increase remote operational capability from 42% to approximately 90% of Hydro One's sub-transmission feeders, enabling faster fault isolation, sectionalization and restoration.
- **D-SS-07 DER Hosting Capacity:** This new program contributes $71.4M to the forecast increase in System Service expenditures. The investment is required to remove feeder constraints for micro-embedded generation on approximately 190 feeders, create more than 43MW of additional hosting capacity, and enable an estimated 3,600 to 4,300 additional customer connections.
- **D-SS-02 Reliability Improvements:** Expenditures for Reliability Improvements increase by $68.8M, from $15.7M for three material investments proceeding in 2023-2027 to $84.5M for 13 material investments in 2028-2032. The increase reflects the greater number of targeted feeders and the feeder-specific scope required to address their high historical contributions to SAIDI. The program will construct new feeder ties, increase transfer capacity, and split long feeders to

reduce outage exposure, improve restoration flexibility, and enhance reliability for affected customers.

- **D-SS-08 System Monitoring:** New investments in System Monitoring account for $51.2M of the period-over-period variance. The program responds to the need for enhanced visibility of asset condition on critical station assets through the deployment of 1,090 dissolved gas analysis devices to monitor 956 station transformers and 270 thermovision devices across 82 critical transformers. Continuous monitoring will help identify developing faults between inspection intervals, enabling earlier intervention and reducing the risk of equipment failures and customer interruptions.

3.8.4 IMPACT OF CAPITAL INVESTMENTS ON OPERATIONS, MAINTENANCE AND ADMINISTRATION EXPENDITURES

Hydro One's OM&A requirements are influenced by factors such as regulatory obligations, customer- and demand-driven activity, inspection and maintenance cycles, asset condition, and the scale of the distribution system. As a result, different categories of capital investment affect ongoing operating requirements in different ways.

Sustainment investments primarily replace or refurbish existing assets and therefore generally have a limited impact on ongoing operating requirements. These investments address selected deteriorated assets and help mitigate the upward pressure on corrective reactive maintenance requirements associated with continued asset deterioration. However, the broader distribution asset base continues to age and deteriorate over the forecast period. In addition, regulatory inspection requirements and established maintenance cycles continue to apply across the asset population, including assets replaced or added through the capital plan. While newer assets generally require less condition-based and corrective maintenance, their replacement does not eliminate ongoing inspection and preventive maintenance requirements. Accordingly, Hydro One expects its renewal and refurbishment capital investments to help manage ongoing OM&A requirements without materially reducing the overall level of sustainment OM&A.

By contrast, investments that expand the distribution system's capabilities through new assets, digital technologies, automation, DER integration, energy storage, and customer-facing services create additional operating, maintenance, monitoring, and support requirements. The most significant OM&A impacts associated with the proposed capital plan relate to investments in AMI 2.0, Distributed Intelligence and Distributed Automation, energy storage, intelligent grid technologies, and DER-related capabilities. These investments support the operation of a more capable, resilient, automated, and digitally enabled distribution system and are necessary to meet evolving customer, regulatory, and system needs.

The following sections provide a more detailed explanation of the impact of Hydro One's capital plan on the various OM&A programs.

Stations

Station OM&A (Exhibit E-03-02, Section 2.1) includes inspections, preventive maintenance, corrective maintenance, and environmental remediation activities. Station OM&A is expected to increase modestly as Hydro One expands and modernizes portions of its station fleet to support load growth. At the same time, station renewal investments replace selected poor condition and end of life assets and help manage corrective and reactive maintenance requirements associated with those assets. However, the broader station asset population continues to age and deteriorate, resulting in ongoing condition-based maintenance requirements across assets that remain in service. Inspection and preventive maintenance requirements also continue to apply across the station asset population, including renewed and newly installed equipment.

Lines

Line OM&A (Exhibit E-03-02, Section 2.2) includes trouble calls, inspections, maintenance activities, customer service requests, and other support functions. A significant portion of this work is driven by regulatory inspection requirements, asset condition and demand-driven requirements. For example, distribution line inspections are completed on prescribed three- and six- year cycles, as described in DSP Section 3.2, subsection 3.2.2.

Programs such as Pole Sustainment, Distribution Lines Minor Component Replacement, Submarine Cable Replacement, and Distribution Lines Sustainment Initiatives are primarily focused on renewing existing infrastructure while largely maintaining the scale and functionality of the distribution system. These investments help manage the condition of the existing asset base and mitigate corrective and reactive maintenance pressures associated with deterioration. However, the broader lines asset population continues to age and deteriorate, and recurring inspection requirements continue to apply to both existing and newly installed assets.

Line additions associated with load growth represent a relatively small increase in total circuit kms and are not expected to materially affect line-related operating requirements. Accordingly, the proposed capital plan is not expected to be a material incremental driver of Lines OM&A.

Meters, Telecom, Protection, Control and Smart Grid

Meters, Telecom, Protection, Control and Smart Grid (Exhibit E-03-02, Sections 2.3 and 2.5) investments have a direct impact on OM&A expenditures.

The deployment of AMI 2.0, Distributed Intelligence and Distributed Automation, advanced grid technologies, and additional monitoring and control devices introduces new ongoing operating requirements for communications networks, software licensing, cybersecurity, data analytics, device maintenance, platform hosting, application support, and specialized technical resources.

Additional OM&A is also required to support battery energy storage systems, DER integration capabilities, advanced distribution management functions, and other intelligent-grid technologies that improve visibility, operational awareness, and grid flexibility.

These expenditures are necessary to support the transition to a more digital, automated, and distributed electricity system while enabling Hydro One to operate and maintain the

expanding set of technologies required to support electrification, DER integration, reliability, and system modernization objectives.

Vegetation Management

Vegetation Management (Exhibit E-03-02, Section 2.4) expenditures are primarily driven by the amount of line infrastructure requiring maintenance, vegetation conditions, and the maintenance cycles required to manage Hydro One's rights-of-way.

Capital investments can affect vegetation maintenance requirements through additions, relocations, or undergrounding of line infrastructure. However, the resulting change in Hydro One's overall overhead line length is small relative to the existing system. Accordingly, the capital plan is not expected to have a material impact on this program.

Development

Development OM&A (Exhibit E-03-03) includes customer connection assessments, engineering and technical studies, project coordination, DER connection activities, distribution standards, and customer power quality activities.

Development OM&A expenditures are expected to increase over the forecast period as the increased 2028-2032 DSP creates additional engineering and technical study requirements. This includes activities required to identify system capability and reinforcement needs and assess system impacts. As DER connection volumes continue to grow across Hydro One's service territory, the increase reflects the engineering studies, technical assessments, coordination activities, and ongoing monitoring required to safely and reliably integrate increasing volumes of customer-driven DER into the distribution system. The introduction of new and evolving technologies and designs also requires the development and updating of Hydro One's distribution technical standards. Accordingly, the proposed capital plan contributes directly to higher Development OM&A requirements.

The following attachment is provided as part of this section:

- Attachment 1 – Distribution Chapter 2 Appendix 2-AA - Capital Projects Table for Distribution

Witness: Paul Ankrett; Peter Faltaous; Spencer Gill

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SECTION 3.8 – ATTACHMENT 1 – DX CHAPTER 2 APPENDIX 2 – AA – CAPITAL PROJECTS FOR DISTRIBUTION

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SECTION 3.9 – DSP – CAPITAL EXPENDITURE VARIANCES

3.9.1 INTRODUCTION

This Exhibit describes the variance between the OEB-approved 2023-2027 distribution capital expenditures and the actual and forecast expenditures over this period. Variances pertaining to General Plant capital expenditures are discussed in GSP 4.9.[1]

The variances described in this Exhibit are relative to Hydro One's December 2022 capital expenditure plan, which forms the basis for the variance and reflects the OEB-approved capital expenditures in accordance with the Settlement Proposal in Hydro One's application for Distribution Rates for 2023-2027 (EB-2021-0110).[2]

Hydro One has prepared detailed variance summaries for material investments within each Investment Summary Document (ISD). Additional variance analysis can be found in Hydro One's 2023-2025 Capital Performance Reports (see DSP Section 3.9, Attachments 2, 3 and 4)[3], and Hydro One's 2026-2027 Capital Performance Summary (see DSP Section 3.9 Attachment 5).

3.9.2 HISTORICAL CAPITAL EXPENDITURES TRENDS AND VARIANCES

3.9.2.1 OVERVIEW

As discussed below, Hydro One has effectively managed total capital expenditures over the 2023-2027 period against a backdrop of unprecedented increases in external demand and non-discretionary work, as well as significant increases in material and equipment

[1] For a comparison of acquisition forecasts to actuals pertaining to the Acquired Distribution Utilities, see Exhibit L-03-01.
[2] In EB-2021-0110, the OEB approved Hydro One's 2023-2027 custom distribution rates application based on the capital expenditure and in-service envelopes outlined in the Settlement Proposal (Decision and Order, November 29, 2022, Schedule A, pp.254-255 and pp.257-258). In December 2022, Hydro One allocated these OEB-approved envelopes to individual programs and projects for each of the five years. This represented the first time where the impacts of the Settlement Proposal were flowed through to the program and project level.
[3] Following the publication of the 2023 and 2024 Capital Performance Reports (CPRs), Hydro One updated the OEB-category mapping of a limited number of investments. As a result, some OEB category-level actual expenditures and in-service additions reported in Table 1 of the 2023 and 2024 CPRs may differ from the updated amounts presented in this Application.

costs. Hydro One Distribution's historical and forecast capital expenditures relative to OEB-approved amounts are summarized in Table 1.

Table 1 - Hydro One - Historical and Bridge Years Capital Expenditure Summary ($M)[4]

	Historical (OEB Approved and Actual / Forecast)												Bridge			Total		
OEB Category	**2023**			**2024**			**2025**			**2026**			**2027**			**2023-2027**		
	OEB Approved	**Actual**	**Variance**	**OEB Approved**	**Actual**	**Variance**	**OEB Approved**	**Actual**	**Variance**	**OEB Approved**	**Historical Fcst**	**Variance**	**OEB Approved**	**Bridge**	**Variance**	**OEB Approved**	**Forecast**	**Variance**
	$M	**$M**	**%**	**$M**	**$M**	**%**	**$M**	**$M**	**%**	**$M**	**$M**	**%**	**$M**	**$M**	**%**	**$M**	**$M**	**%**
1.System Access	252.2	335.9	33.2%	253.3	355.2	40.2%	238.9	340.6	42.6%	223.8	342.2	52.9%	215.0	333.6	55.2%	1,183.1	1,707.4	44.3%
2.System Renewal (Excl. AMI 2.0)	282.0	264.5	-6.2%	287.0	381.5	32.9%	280.6	422.3	50.5%	277.8	242.0	-12.9%	280.6	202.0	-28.0%	1,408.0	1,512.2	7.4%
3.System Renewal (AMI 2.0 Only)	32.5	27.9	-14.2%	69.5	54.9	-21.0%	158.4	94.6	-40.3%	158.9	183.0	15.2%	161.8	186.5	15.3%	581.0	546.9	-5.9%
4.System Service	182.0	166.9	-8.3%	157.2	165.1	5.0%	212.6	108.4	-49.0%	177.9	282.0	58.5%	190.7	316.3	65.9%	920.4	1,038.7	12.9%
Subtotal Categories 1, 2, 3 and 4	**748.6**	**795.2**	6.2%	**767.0**	**956.6**	24.7%	**890.5**	**965.8**	8.5%	**838.3**	**1,049.1**	25.1%	**848.1**	**1,038.4**	22.4%	**4,092.5**	**4,805.1**	17.4%
5.General Plant Allocated to Distribution	172.2	194.1	12.7%	182.2	169.1	-7.2%	149.5	118.7	-20.6%	154.2	121.5	-21.2%	143.2	119.2	-16.8%	801.3	722.6	-9.8%
Total Distribution Capital	**920.8**	**989.2**	**7.4%**	**949.2**	**1,125.7**	**18.6%**	**1,040.0**	**1,084.6**	**4.3%**	**992.5**	**1,170.5**	**17.9%**	**991.3**	**1,157.5**	**16.8%**	**4,893.8**	**5,527.7**	**13.0%**
Prepaid Related to Cloud	0.0	0.0	-	0.0	10.0	-	0.0	31.1	-	0.0	70.0	-	0.0	48.6	-	0.0	159.7	-

[4] Figures presented in the tables may not sum to the totals shown due to rounding.

Witness: Paul Ankrett; Gianni DiFilippo; Peter Faltaous; Spencer Gill

This section provides a variance analysis of Hydro One Distribution's historical actual and forecast expenditures as compared to its planned and OEB-approved capital expenditures for the 2023-2027 rate period. As outlined in Table 1, total capital expenditures over the five-year historical and bridge period are forecast to be $5,527.7M compared to the OEB-approved envelope of $4,893.8M, representing a variance of $633.9M, or approximately 13.0% higher. Excluding General Plant, Distribution capital expenditures are forecast to be $4,805.1M compared to the OEB-approved envelope of $4,092.5M, representing a variance of $712.6M, or approximately 17.4% higher. In both cases, the March 2025 ice storm accounted for approximately $187.0M of the variance.

Over the 2023-2027 period, Hydro One experienced a change in operating conditions, material and unanticipated increase in demand-driven and mandatory work, and higher-than-assumed costs across the capital portfolio. The result was a 44.3% increase in System Access driven by higher connection-related and externally driven work than contemplated during the 2023-2027 period, including new load connections, service upgrades, relocations, and DER-related activity. In System Service, Hydro One responded to earlier and higher load materialization, increased demand-driven system modifications, and a higher volume and severity of power quality and stray voltage work resulting in a 12.9% increase over the OEB-approved plan. System Renewal investments (excluding AMI) increased by 7.4% as Hydro One incurred higher expenditures in storm response, compliance-driven replacement, and failure-driven station work.

Growth in demand-driven work requirements, combined with persistent and elevated inflation and cost pressures (as discussed in SPF Section 1.8), materially changed Hydro One's capital expenditures over the 2023-2027 rate period. Hydro One directed available capital toward increased demand-driven and mandatory work, including customer connection, safety, reliability, compliance, and customer service requirements. To manage within its overall capital envelope, Hydro One pursued investment reductions, deferrals, or rephasing of planned investments, principally within its planned condition-based System Renewal programs and select System Service reliability and resiliency focused programs. These trade-offs and mitigations were undertaken through portfolio-

level reprioritization (consistent with the approach described in SPF Section 1.7), pacing adjustments, and disciplined scope management.

The variances outlined in this exhibit thus reflect a material change in the mix and scope of work delivered over the 2023-2027 period relative to the approved plan. As detailed throughout this evidence and the applicable ISDs, Hydro One completed more customer connections, external relocations, load-driven system upgrades, power quality interventions, storm restoration, compliance-focused replacements, and failure-driven renewal work than originally contemplated. At the same time, Hydro One completed less planned condition-based renewal work and less selected reliability and resiliency scope than originally forecast, with certain asset replacement, refurbishment, feeder tie, remote switching, and energy storage work deferred or shifted beyond the current period.

Overall, changes in the mix and scope of the work delivered, combined with persistent inflation and cost pressures, reduced the volume of work that could be completed within available funding, extending renewal cycles in certain asset classes and increasing the amount of work requiring attention in the subsequent period.

Though best efforts were undertaken, Hydro One could not fully offset the impacts of the demand-driven challenges and market-based cost pressures it faced during the 2023-2027 period. As a result, despite the substantial deferral of planned work across several programs, Hydro One's Distribution capital expenditures over the historical and bridge period are forecast to be approximately 13.0% above the OEB-approved envelope.

Through its capital planning and execution processes, Hydro One strives to maximize risk mitigation with available expenditures, while balancing operational factors such as outage schedules, equipment availability, and resource capacity to ensure work remains deliverable. Each investment is assessed on the basis of risk mitigation, with work prioritized based on risk mitigated per dollar, or Risk Spend Efficiency, producing a risk-informed, optimized plan. Hydro One focuses on optimizing both executability and risk reduction, sequencing work based on risk priority and execution readiness. This approach

maximizes the level of risk mitigated within available budgets and operational windows, with work deferred and reassessed through the planning cycle.

While work optimization is necessary and enables the company to respond to evolving demands and cost pressures, continued deferral of investments will result in a growing population of assets in poor and deteriorating condition and an accumulation of system risks associated with the continued operation of those assets. Restoring planned investment levels to a sustainable pace is therefore critical to maintaining the safe and reliable operation of the system and mitigating long-term system performance risks.

Hydro One continues to deliver its capital program with a strong emphasis on safety. Despite significant changes in work volumes, operating conditions, and customer-driven requirements, Hydro One Distribution maintained a recordable injury rate of approximately 1.0 over 2023-2025, as discussed in DSP Section 3.10, subsection 3.10.4. This performance reflects Hydro One's embedded safety culture and its commitment to operational excellence.

Sections 3.9.2.2, 3.9.2.3, and 3.9.2.4 summarize the capital spending and variances within the System Access, System Renewal, and System Service categories, respectively.

3.9.2.2 SYSTEM ACCESS

System Access investments are primarily customer and third-party-driven expenditures that Hydro One is required to undertake to connect customers, complete relocations and other externally-driven work, and meet mandated service requirements and regulatory obligations.

Table 2 presents the 2023-2027 OEB-approved and historical actual and forecast System Access expenditures, which are expected to exceed planned levels by $524.3M (44.3%) over the current rate period. System Access expenditures were significantly above plan as Hydro One responded to higher-than-anticipated customer and third-party demand for connections, service upgrades, relocations and DER-related work. These investments are mandatory because they are driven by customer requirements and regulatory obligations,

limiting Hydro One's ability to offset expenditures through trade-offs within the category. The key drivers of the variance are discussed below.

Table 2 - Hydro One – Historical and Bridge System Access ($M)

OEB Category	Historical (OEB Approved and Actual / Forecast)												Bridge			Total		
	2023			2024			2025			2026			2027			2023-2027		
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Bridge	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
1.System Access	252.2	335.9	33.2%	253.3	355.2	40.2%	238.9	340.6	42.6%	223.8	342.2	52.9%	215.0	333.6	55.2%	1,183.1	1,707.4	44.3%

The System Access variances identified in Table 2 are primarily driven by increased volumes of work and higher expenditures in New Load Connections, Upgrades and Cancellations (DSP Section 3.11, D-SA-02), Joint Use and Relocations (DSP Section 3.11, D-SA-01), and Customer Demand DER (DSP Section 3.11, D-SA-03). These increases were partially offset by lower Metering Sustainment (DSP Section 3.11, D-SA-04) expenditures resulting from fewer-than-forecast AMI 1.0 meter failures.

The largest variance occurred in New Load Connections, Upgrades and Cancellations (DSP Section 3.11, D-SA-02) and was primarily attributable to higher-than-planned customer-driven work volumes, market-wide material cost escalation, and an increasing scope and complexity of customer connection and service upgrade projects. Service upgrade activity increased materially above plan as customers sought larger electrical services and electrification-related upgrades, while connection volumes were influenced by fluctuating subdivision development activity. Program costs were further impacted by significant increases in the cost of key materials, including transformers, conductors, cables, wires, and poles as discussed in SPF Section 1.8. In addition, an increasing number of projects required more extensive distribution system modifications, resulting in higher design, construction, and material requirements. Refer to DSP Section 3.11, D-SA-02 for further details.

Joint Use and Relocations (DSP Section 3.11, D-SA-01) also exceeded plan, with forecast net capital expenditures of $229.7M compared to $141.5M planned. The variance was concentrated in the Relocations segment, where forecast expenditures of $170.6M exceeded the planned $55.3M. This increase was driven by higher-than-expected relocation volumes, particularly projects initiated by municipal road authorities and the Ministry of Transportation, including major infrastructure projects such as Metrolinx electrification and expansion initiatives, the Bradford Bypass, and Highway 413. Program costs were further impacted by the broader market-wide cost pressures discussed in SPF Section 1.8. These increases were partially offset by Joint Use expenditures of $59.9M compared to $86.2M planned, reflecting lower-than-forecast application volumes. Refer to DSP Section 3.11, D-SA-01 for further details.

Metering Sustainment expenditures partially offset the category increase. On a volume basis, Hydro One forecasts 174,399 failed AMI 1.0 meters over the 2023-2027 period, compared to 316,360 replacements planned. The lower expenditures were driven primarily by lower-than-forecast AMI 1.0 meter failure volumes, which reduced the number of mandatory meter replacements required during the period. Hydro One continued to replace failed meters as required to support reliable and accurate customer billing and compliance with applicable metering requirements. Refer to DSP Section 3.11, D-SA-04 for further details.

3.9.2.3 SYSTEM RENEWAL

System Renewal investments address asset condition, failure, safety, environmental compliance and lifecycle requirements.

Table 3 below presents the 2023-2027 OEB-approved and historical actual and forecast System Renewal expenditures. The AMI 2.0 expenditures are shown separately for ease of reference, as these amounts are subject to a dedicated variance account. Over the 2023-2027 period, System Renewal expenditures exceed planned levels by $70.1M (3.5%), with forecast expenditures of $2,059.1M compared to planned levels of $1,989.0M. Excluding AMI 2.0, expenditures are forecast to exceed planned levels by $104.2M (7.4%). The variance reflects a material change in the composition of work delivered, with higher expenditures for storm restoration, PCB compliance and failure-driven station replacements partially offset by lower condition-based planned renewal expenditures and the rephasing of AMI 2.0. The key drivers of the variance are discussed below.

Table 3 - Hydro One System Renewal - Historical and Bridge System Renewal

OEB Category	Historical (OEB Approved and Actual / Forecast)												Bridge			Total		
	2023			2024			2025			2026			2027			2023-2027		
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Bridge	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
2. System Renewal (Excl. AMI 2.0)	282.0	264.5	-6.2%	287.0	381.5	32.9%	280.6	422.3	50.5%	277.8	242.0	-12.9%	280.6	202.0	-28.0%	1,408.0	1,512.2	7.4%
3. System Renewal (AMI 2.0 Only)	32.5	27.9	-14.2%	69.5	54.9	-21.0%	158.4	94.6	-40.3%	158.9	183.0	15.2%	161.8	186.5	15.3%	581.0	546.9	-5.9%

The Distribution Lines Trouble Call and Storm Damage Response (DSP Section 3.11, D-SR-05) program represents the largest variance in the System Renewal category. Net capital expenditures are forecasted to increase from planned expenditures of $580.6M to approximately $972.3M, an increase of approximately $391.7M (67.5%). The variance is primarily attributable to the increased frequency and severity of storm activity experienced during the period. In particular, the March 2025 ice storm resulted in unprecedented damage to the distribution system and extensive restoration requirements, contributing approximately $187.0M[5] of the total variance. The storm caused approximately 1.22 million customer interruptions affecting more than 600,000 customers. Further details are provided in DSP Section 3.11, D-SR-05.

Distribution Lines PCB Equipment Replacement (DSP Section 3.11, D-SR-06) also exceeded plan. Forecast expenditures of $76.2M exceeded the planned $29.8M by $46.4M (155.7%). The increase was driven by Hydro One's prioritization of PCB-containing equipment replacements to meet applicable environmental compliance deadlines. To support the completion of the program, additional external resources were utilized to supplement the internal execution capacity. Program costs were also impacted by a higher-than-expected number of replacements that extended beyond a like-for-like equipment replacement. In these cases, associated assets required replacement, including supporting poles, as well as additional design work required to accommodate new transformer configurations. The PCB replacement program is expected to be completed by the end of 2026.

Distribution Stations Demand Capital (DSP Section 3.11, D-SR-01) investment also exceeded planned levels, with actual and forecast expenditures of $70.2M, approximately $36.4M (107.7%) above the planned $33.8M. The increase is driven by both higher-than-planned replacement volumes and broader project scope. Actual accomplishments during the 2023-2025 period were approximately 17% higher than planned. In addition, approximately 62% of transformer replacements required expanded scopes to address transformer overloading and install higher-capacity units. These replacements frequently

[5] $187.0M are the Z-factor related net capital expenditures for Hydro One Networks. Total for all rate zones is $196.2M.

required associated station upgrades, including higher-rated reclosers, insulators and bus, ground-grid work, and station footprint expansions and Mobile Unit Substation connection facilities. Program costs were further impacted by increases in equipment and material costs. Further details are provided in DSP Section 3.11, D-SR-01.

Hydro One responded to increased storm restoration, environmental compliance, and failure-driven replacement requirements by reprioritizing capital from planned condition-based renewal investments. The most significant reductions occurred in Pole Sustainment (DSP Section 3.11, D-SR-07), Distribution Station Refurbishment (DSP Section 3.11, D-SR-04) and Submarine Cable Replacement (DSP Section 3.11, D-SR-09). While these actions enabled Hydro One to address immediate safety, reliability, compliance and emergent needs, the underlying condition-based renewal requirements remained and continue to inform the 2028-2032 plan.

Pole Sustainment (DSP Section 3.11, D-SR-07) expenditures were below planned levels, with actual and forecast expenditures of $177.7M compared to planned expenditures of $390.8M, a reduction of $213.1M (54.5%). The reduction was driven primarily by the reprioritization of planned pole replacement work to address urgent storm restoration needs, as well as demand-driven and compliance-related requirements. To manage the reliability risks associated with deferred pole replacements, Hydro One continued pole testing, treatment and structural refurbishment where cost-effective and operationally appropriate. Further details are provided in DSP Section 3.11, D-SR-07.

Distribution Station Renewal (DSP Section 3.11, D-SR-04) expenditures were below planned levels, with actual and forecast expenditures of $28.3M compared to planned expenditures of $89.3M, a reduction of $61.0M (68.3%)[6]. The variance reflects the reprioritization of capital to demand-driven mandatory work, resulting in the deferral of a significant number of planned station renewal and refurbishment projects.

[6] The continued scope of the Life-Cycle Optimization ISD (D-SR-11) is incorporated into D-SR-04 for the 2028-2032 period, and hence is included in this historical plan comparison

Submarine Cable Replacement (DSP Section 3.11, D-SR-09) expenditures were below planned levels, with actual and forecast expenditures of $10.4M compared to planned expenditures of $66.9M, a reduction of $56.5M (84.5%). The variance was driven by the reprioritization of capital funding to support higher-priority storm response, demand-driven work and compliance related requirements. Program execution was further impacted by material availability constraints during the earlier years of the current rate term, resulting in lower expenditures as manufacturers were unable to meet demand. In response, Hydro One prioritized replacement of the most severely degraded cables and addressed immediate hazards through the Trouble Call and Storm Damage Response program. As a result of the reprioritization of capital funding, a larger population of damaged and exposed submarine cables remains to be addressed in the subsequent period. Further details are provided in DSP Section 3.11, D-SR-09.

AMI 2.0 (DSP Section 3.11, D-SR-12) expenditures were below planned levels, with actual and forecast expenditures of $546.9M compared to the OEB-approved amount of $581.0M, a reduction of $34.1M (5.9%). The variance reflects a change in program sequencing, with mass meter deployments and communication-network device installations shifting by one year. As a result, Hydro One now forecasts completion of meter and network deployment in 2029. Further details are provided in Section 3.11, D-SR-12.

Overall, System Renewal expenditures reflect Hydro One's reprioritization of capital to address higher-priority storm response, compliance, demand-driven, and failure-driven requirements, resulting in the deferral or rephasing of certain condition-based renewal investments.

3.9.2.4 SYSTEM SERVICE

System Service includes customer- and demand-driven system upgrades, safety and power quality work, and planned reliability and resiliency investments.

Table 4 presents the 2023-2027 OEB-approved and historical actual and forecast System Service expenditures. In total, System Service expenditures are forecasted to be $118.3M (12.9%) above planned levels over the 2023-2027 period. The variance reflects higher load growth and demand-driven investment requirements than contemplated in the OEB-approved plan. Hydro One partially offset these requirements by completing less energy storage and distribution automation work, prioritizing capital and delivery resources to address the most immediate capacity, customer service, safety, and regulatory requirements. Detailed explanations of the significant program-level variances are provided below.

Table 4 - Hydro One - System Service - Historical and Bridge System Service ($M)

OEB Category	Historical (OEB Approved and Actual / Forecast)												Bridge			Total		
	2023			2024			2025			2026			2027			2023-2027		
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Bridge	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
4.System Service	182.0	166.9	-8.3%	157.2	165.1	5.0%	212.6	108.4	-49.0%	177.9	282.0	58.5%	190.7	316.3	65.9%	920.4	1,038.7	12.9%

System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01) represented the largest program variance within System Service. Capital expenditures in this program increased from $465.7M planned to $666.8M actual and forecast, a variance of $201.1M (43.2%). The variance was primarily attributable to load-growth materializing earlier and at a greater rate than forecast when the plan was developed. As a result, a greater number of stations and feeders reached, or are forecast to reach, their planning limits earlier than anticipated. Hydro One expects to complete 123 material investments compared to 93 planned, including additional feeder builds, station reinforcements and other system upgrades identified through planning assessments. Further details are provided in DSP Section 3.11, D-SS-01.

Demand System Modifications (DSP Section 3.11, D-SS-03) expenditures increased from $71.9M planned to $118.6M actual and forecast, a variance of $46.7M (65.0%). The variance was primarily attributable to a higher volume of immediate and near-term system modifications required to address localized load-growth and customer-driven requirements. The additional work included equipment upgrades, protection modifications, voltage regulation, feeder balancing and other targeted investments required to address thermal loading, protection and power quality limitations. The increases in the cost of materials and equipment, including voltage regulators and reclosers as discussed in SPF Section 1.8, also contributed to the variance. Refer to DSP Section 3.11, D-SS-03 for further details.

Other Distribution System Service Investments (D-SS-Other) expenditures increased from $0.7M planned to $27.4M actual and forecast, an increase of $26.7M. This is primarily driven by the development of the Intelligent Grid Platform. Hydro One's 2023-2027 investment plan included an Outage Management System (OMS) and Distribution Management System (DMS) to address aging systems, increasing maintenance costs, and reliability risks. Prior to implementing these solutions, Hydro One reassessed its long-term operational requirements and determined that an integrated Advanced Distribution Management System (ADMS) platform represented a more prudent long-term solution than proceeding with standalone distribution and outage management system upgrades. The integrated solution consolidates distribution and outage management capabilities

within a single platform, addressing identified obsolescence risks while supporting enhanced operational, outage response, and system planning capabilities. Further details regarding the overall ADMS and OMS upgrades and related program changes are provided in DSP Section 2.11, D-SS-09.

Energy Storage Solutions (DSP Section 3.11, D-SS-04) expenditures decreased from $129.8M planned to $36.3M actual and forecast, a reduction of $93.5M (72.0%). The variance was primarily attributable to the reprioritization of capital and delivery resources to address higher-priority load-growth, demand-driven, safety, and regulatory requirements, resulting in the deferral of a significant portion of the planned energy storage scope. Hydro One is forecast to deliver one grid-scale battery energy storage project and approximately 360 residential battery installations, compared to a planned portfolio of six grid-scale projects and approximately 1,300 residential battery installations. Market-wide cost pressures, as discussed in SPF Section 1.8, also contributed to the reduction in scope. Refer to DSP Section 3.11, D-SS-04 for further details.

Distribution Automation and Sectionalization (DSP Section 3.11, D-SS-05), formerly the Worst Performing Feeders program, was below planned levels over the 2023-2027 period. Actual and forecast net capital expenditures for remote operable devices and Communicating Fault Circuit Indicators were $111.0M compared to planned expenditures of $192.0M, a reduction of $81.0M (42.2%). The variance was primarily attributable to the reprioritization of capital and delivery resources to address higher-priority customer connection, load-growth, storm response, safety, and compliance requirements. As a result, a portion of the planned remote operable device scope was deferred. The deferred work remains part of Hydro One's longer-term distribution automation objectives. Refer to DSP Section 3.11, D-SS-05 for further details.

Overall, the System Service portfolio reflects Hydro One's prioritization of capital and delivery resources to address the most immediate capacity, customer service, safety, and regulatory requirements. As a result, certain reliability and resiliency investments were deferred, and this deferred scope continues to inform the proposed 2028-2032 plan.

The following attachment is provided as part of this section:

- Attachment 1 – Dx Chapter 2 Appendix 2-AA – Capital Expenditures Summary

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SECTION 3.9 – ATTACHMENT 1 – CHAPTER 2 APPENDIX 2-AB: CAPITAL EXPENDITURES SUMMARY FOR DISTRIBUTION

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DISTRIBUTION CAPITAL PERFORMANCE REPORT – 2023

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2023 in relation to the overall Distribution capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) delivered by Hydro One.

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Settlement Implementation Forecast" or the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal to the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL

Table 1 below presents a breakdown of the actual 2023 capital Distribution expenditures and ISA by OEB investment category and compares them against the OEB-approved Settlement Proposal. The primary focus of this report is on the Distribution System Access, System Renewal, and System Service categories. The Distribution General Plant category is discussed in the General Plant Capital Performance Report.

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

Table 1 - 2023 Distribution Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2023			In-Service Additions – 2023		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	$252.2	$335.9	$83.7	$252.1	$337.3	$85.3
System Renewal (Excl. AMI 2.0)	$282.0	$264.7	-$17.3	$270.6	$250.3	-$20.2
System Renewal (AMI 2.0 Only)	$32.5	$27.9	-$4.6	$32.4	$0.0	-$32.4
System Service	$182.0	$166.9	-$15.1	$218.1	$149.7	-$68.4
General Plant	$172.2	$194.5	$22.3	$136.9	$235.1	$98.2
Total	**$920.8**	**$989.8**	**$69.0**	**$910.0**	**$972.5**	**$62.5**

Overall, Hydro One's distribution capital expenditures for 2023 were 7% above the OEB-approved amount and ISA for 2023 were 7% above the OEB-approved amount. The increase in Hydro One's distribution capital expenditures and ISAs was largely due to a shift in priorities to focus on connecting new homes and businesses. Additionally, inflationary pressures - including rising costs of goods, services, and labour - and an increase in severe weather events have had an impact. Accordingly, Hydro One has responded to these circumstances by reprioritizing and re-pacing its capital portfolio where it was possible to do so.

To partly offset these increases in the System Access category (i.e., customer driven), and demand driven work within System Renewal category (e.g., trouble calls and storm damage), Hydro One made reductions in System Renewal (i.e. pole replacement, sustainment programs) and System Service (i.e., system upgrade) categories. The OEB categories and associated variance explanations are outlined below.

System Access: System Access capital expenditures and ISAs were higher than the OEB-approved amount by $83.7M and $85.3M respectively. These variances were primarily driven by a higher volume of New Load Connections and Service Upgrades (D-SA-02), including more complex large connection projects. The increase in this demand driven investment category also impacted costs associated with design and estimation

[2] Does not include Hydro One affiliates.
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.257-58 (Table 25 and 26)

due to increased project complexity and varying scope compared to historical requests. In addition, there were higher than planned line relocations and third-party attachment requests which contributed to higher spend. Higher costs in the above investments were partly offset by lower expenditures in metering infrastructure due to lower volume.

System Renewal: Capital expenditures and ISAs were lower than the OEB-approved amount by $21.9M and $52.6M respectively. These variances were primarily driven by investment reprioritization to accommodate mandatory System Access investments that emerged. The reduced spend in some programs in this category were partly offset by higher expenditures in the Distribution Lines Storm Damage & Trouble Call Response (D-SR-05) programs due to higher volume, and higher expenditures in PCB equipment replacement (D-SR-06) and the Distribution Stations demand program (D-SR-01). Hydro One reprioritized System Renewal work within Pole Replacement (D-SR-07), and Submarine Cable Replacement (D-SR-09) to manage within the overall Distribution capital expenditure and ISA envelopes while maintaining a safe and reliable distribution network. Furthermore, the pace of the Advanced Meter Infrastructure (AMI 2.0) implementation (D-SR-12) was adjusted to allow for additional scope refinement and to address integration issues.

System Service: Capital expenditures and ISAs were lower than the OEB-approved amount by $15.1M and $68.4M respectively. Some of the variances were driven by investment reprioritization to accommodate mandatory System Access investments that emerged. Deferrals included a delayed start to the Energy Storage Solutions Program (D-SS-04), and several reprioritized Load Growth projects (D-SS-01) given slower than anticipated load growth in some locations.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM 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 largely 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. Capital expenditure variances at the program-level are discussed in Section 4.0, and project-level variances are discussed in Section 5.0.

The projects and programs discussed in this report represent 97% of the 2023 actual ISA that is shown in Table 1 (for the System Access, System Renewal and System Service categories) and as such provide a very strong indication of the overall portfolio performance.

3.1 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual in-service additions (ISA) in 2023 greater than or equal to $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[4]:

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – For programs, material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2023 or earlier, to a later year.

The reasons for variances in individual projects and programs fall into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

[4] Hydro One updated this report's variance criteria to conform with its internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes 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 without necessarily materially changing the in-service amount or affecting the overall volume of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors, as well as customer needs.

Work Definition

Work definition variances arise from the process of refining a project's scope, estimated budget and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or decreases in 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.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

4.0 PROGRAM PERFORMANCE

A large portion of Distribution's capital work program includes investments that are driven by demand and require action in a specified period as part of Hydro One's obligations under the 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 aiming to minimize the impacts of deferring planned investments that can introduce additional risks to the system in future years. Distribution Capital Program variances are summarized in Table 2 and further discussed below.

Table 21 - Distribution Program Summary

			2023 Dx Capital Expenditures ($M)			2023 Dx In-Service Additions ($M)			2023 Dx Units				Performance
OEB Category	Program Description		Forecast	Actual	Variance	Forecast	Actual	Variance	Unit Description	Forecast	Actual	Variance	Variance Category
System Access	D-SA-01	Joint Use and Relocations	25.1	45.9	20.8	32.3	50.4	18.1	None	N/A	N/A	N/A	Emergent Needs
	D-SA-02	New Load Connections and Upgrades	158.6	257.7	99.1	177.6	256.6	79.0	# of Connections, & Upgrades	21,326	25,078	3,752	Emergent Needs
	D-SA-04	Metering Sustainment	56.2	30.2	-26.1	55.7	28.7	-27.0	# of Meters Replaced	100,041	50,022	-50,019	Work Definition
System Renewal	D-SR-01	Distribution Stations Demand Capital Program	6.5	15.2	8.7	8.0	13.3	5.4	None	N/A	N/A	N/A	Emergent Needs
	D-SR-02	Mobile Unit Substation Program	4.9	3.3	-1.6	3.4	0.1	-3.3	# of MUS	1	0	-1	Execution Factors
	D-SR-03	Distribution Station Planned Component Replacement Program	4.7	5.5	0.9	5.7	6.8	1.2	# of Recloser & MUS Structures	163	119	-44	Work Definition
	D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	111.6	141.4	29.9	117.0	141.1	24.1	None	N/A	N/A	N/A	Emergent Needs
	D-SR-06	Distribution Lines PCB Equipment Replacement Program	9.9	14.7	4.7	10.0	14.7	4.7	# of Transformer Replacements	1,529	1,481	-48	Work Definition
	D-SR-07	Pole Replacement	58.0	34.7	-23.4	58.8	34.0	-24.8	# of Pole Replacements	5933	2509	-3,424	Reprioritization
	D-SR-07	Wood Pole Test and Treat	10.3	13.7	3.4	10.4	13.3	2.9	# of Poles Tested	101,617	114,400	12,783	Emergent Needs
	D-SR-07	Wood Pole Structural Refurbishment	6.3	6.1	-0.2	6.4	6.1	-0.2	# of Poles Refurbished	2,785	4,475	1,690	Emergent Needs
	D-SR-08	Distribution Lines Minor Component Replacement Program	13.0	10.1	-3.0	7.9	10.1	2.2	# of Components Replaced	3,610	3,444	-166	Reprioritization
	D-SR-09	Submarine Cable Replacement Program	12.8	2.7	-10.1	12.1	2.7	-9.4	None	N/A	N/A	N/A	Reprioritization
	D-SR-10	Distribution Lines Sustainment Initiatives	8.0	4.5	-3.5	12.1	3.2	-8.9	None	N/A	N/A	N/A	Reprioritization
System Service	D-SS-03	Demand Investments	13.9	24.6	10.7	10.6	23.1	12.5	None	N/A	N/A	N/A	Emergent Needs
	D-SS-04	Energy Storage Solutions	10.1	3.1	-7.0	6.7	2.0	-4.7	# of Battery Systems Installed	200	61	0	Execution Factors
	D-SS-05	Worst Performing Feeders	36.3	36.0	-0.3	37.2	35.4	-1.8	# of Devices	1,013	1,277	264	Work Definition
	D-SS-06	Stray Voltage	4.0	5.6	1.6	4.0	5.5	1.5	None	N/A	N/A	N/A	Emergent Needs

The **Joint Use and Lines Relocations (D-SA-01)** program expenditures were above the Forecast. This was largely due to a higher volume of work, increased complexity in large line relocation projects, and pressures outlined in Section 2.0 above. 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.

The **New Load Connection, Upgrades, Cancellations (D-SA-02)** program expenditures were above the Forecast. This variance was the largest within the System Access category due to higher demand compared to Forecast. This demand was due to an increased volume of connections, including more large connections which are more expensive to design and construct. This program also experienced higher costs due to pressures outlined in Section 2.0 above. There was also an increase in the volume and size of residential subdivision projects although the connections within those subdivisions will be recorded when residential owners connect to the distribution system.

The **Meter Infrastructure Sustainment (D-SA-04)** program expenditures were below the Forecast largely due to a lower volume of meter failures than initially projected.

The **Distribution Stations Demand Capital (D-SR-01)** program expenditures were above the Forecast due to higher than forecast equipment failures and system upgrades. This work is demand-driven requiring Hydro One to respond to emergent needs. Costs in this category will vary depending on the type of failure, which can range from individual component replacements such as failed switches or electronic reclosers, to failed transformer replacements.

The **Mobile Unit Substations (D-SR-02)** program expenditures were below the Forecast. Due to the failure of a new MUS unit during commissioning, the unit was sent back to the supplier resulting in the delivery being delayed to early 2024.

The **Distribution Station Planned Component Replacement (D-SR-03)** program expenditures were above the Forecast due to a higher volume of work and added scope such as fence replacement, yard extension, and grounding required to accommodate an MUS. The Distribution Station Planned Component Replacement program addresses the planned replacement of individual components in distribution stations.

The **Distribution Lines Trouble Call and Storm Damage Response (D-SR-05)** program expenditures were above the Forecast due to a higher volume of storm damage and trouble call related equipment failure and replacement. This program also experienced higher costs due to pressures outlined in Section 2.0 above. This program includes Trouble Call Poles & Equipment Replacement, Storm Damage, Trouble Sub and Underground Cable Replacement, Post Trouble Call, and Damage Claims.

The **Distribution Lines PCB Equipment Replacement Program (D-SR-06)** program expenditures were above the Forecast due to program acceleration and utilization of added external resources to help ensure compliance with environmental provisions.

Replacement costs were higher where equipment replacement was not like-for-like. Some replacements required a detailed design to accommodate new requirements (e.g., it requires replacement of the pole and transformer).

The **Pole Sustainment Program (D-SR-07)** program contains the Pole Replacement, Wood Pole Test and Treat, and Wood Pole Structural Refurbishment programs. Pole Test and Treat expenditures were above the Forecast due to a larger volume of poles tested and treated. Pole Refurbishment expenditures were slightly below the Forecast, but more poles were refurbished at a lower cost due to efficiencies in execution. Despite significant pressure in demand-driven higher priority work that resulted in reprioritization of resources from pole replacement, Hydro One made efforts to complete pole test and treat and pole refurbishment programs to offset the lower accomplishment and sustain reliability.

The **Distribution Lines Minor Component Replacement Program (D-SR-08)** program in-service additions were above the Forecast due to pressures outlined in Section 2.0 above. Work was reprioritized where feasible. Some of the replacements were also more complex and labour-intensive. Since customer driven work remained elevated throughout the year, Hydro One also leveraged external resources to complete work.

The **Submarine Cable Replacement Program (D-SR-09)** program expenditures were below the Forecast. This was largely due to work reprioritization, where funding for this program was redirected to other higher priority demand-driven work.

The **Distribution Lines Sustainment Initiatives (D-SR-10)** program expenditures were below the Forecast. This was largely due to work reprioritization, where funding for this program was redirected to other higher priority system access investments.

The **Demand Investments (D-SS-03)** program expenditures were above the Forecast due to higher than anticipated costs for work to address localized load growth. These investments include minor distribution system modifications that address system needs identified by customer power quality complaints, feeder studies and system impact assessments. This work is often high priority in nature and requires Hydro One to respond promptly.

The **Energy Storage Solutions (D-SS-04)** program expenditures were below the Forecast due to contracting delays and changing work execution requirements. Energy Storage Solutions include both behind-the-meter Residential Storage for Customers Experiencing Long Interruption Duration (CELID) and front-of-the-meter Grid Scale Storage. Grid Scale Battery Energy Storage Systems are complex and require supporting studies and analysis that have extended the RFP timelines.

The **Worst Performing Feeders Program (D-SS-05)** program expenditures were below the Forecast however unit accomplishments were above the Forecast. Higher than Forecast unit accomplishments were the result of work execution enhancements leading to minimized delays, increased efficiency, and reduced cost.

The **Stray Voltage (D-SS-06)** program expenditures were above the Forecast due to the nature of this program and the volume of work that is required to respond to and correct power quality complaints.

5.0 PROJECT PERFORMANCE

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 load growth. Accordingly, Hydro One focuses on adherence to the total project cost rather than adherence to in-year expenditures.

Table 3 summarizes the projects that met the criteria of a material 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 variance threshold. Hydro One continues to manage its capital expenditures through its investment planning process which prioritizes investments that mitigate the highest risk for the lowest cost. The balance of risks, system needs, and capital requirements that underpin a project deferral will continue to be monitored and reprioritized in conformance with the investment planning process. The 8 projects in Table 3 above are either in Planning, Deferred, Execution, or Completed phase. Variance explanations have been provided for these where required using the criteria outlined in Section 3.1 above.

Table 3 - Distribution Project Summary

			2023 Dx Capital Expenditures ($M)		2023 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[5]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance	Variance Category
Vanastra DS Transformers	Execution	D-SR-04	4.2	0.9	4.3	0.0	4.3	5.8	1.5	2023	2024	1	Work Definition
Beckwith DS F3 Feeder Development	Complete	D-SS-01	3.2	3.4	3.7	3.6	3.7	3.6	-0.1	2023	2023	0	Not a material variance
New Old School DS and feeders	Execution	D-SS-01	6.2	5.9	11.2	9.8	11.2	9.8	-1.4	2023	2023	0	Work Definition
Wikwemikong Supply - Station & Line Work	Execution	D-SS-01	4.8	8.2	6.0	0.0	6.0	9.1	3.1	2023	2024	1	Execution factors
South Middle Road TS DESN1 Feeder Development	Execution	D-SS-01	14.9	32.3	43.8	53.1	130.5	140.6	10.1	2025	2025	0	Not a Material Variance
Curve Inn DS New Feeder	Execution	D-SS-01	5.0	3.4	5.6	0.0	5.6	4.6	-1.0	2023	2024	1	Execution factors
Kirkland Lake Voltage Conversion - Stage 2	Execution	D-SS-01	3.1	1.7	3.9	2.1	3.9	3.2	-0.7	2023	2023	0	Not a material variance
AMI 2.0	Execution	D-SR-12	32.5	27.9	6.8	0.0	705.6	810.6	105.0	2029	2029	0	Execution Factors

[5] Phases: Planning, Execution, Complete, Cancelled, or Deferred.

Several factors impacted project costs and schedule:

Variances between Actual Cost and Preliminary Design Estimates: Initially, project total cost estimates are based on preliminary design, scope, and cost assessments. As projects move towards execution and detailed scoping, project estimates may increase or decrease. In some cases, optimization during detailed design and work execution resulted in a reduction in total project costs compared to plan. Two examples of this are the Curve Inn DS Feeder (D-SS-01) project, and New Old School DS (D-SS-01) project. However, in other cases such as Vanastra DS Transformers (D-SR-04) where detailed design resulted in an increase in total project costs.

Resource Balancing: Increased storm activity, and increased demand from system access programs resulted in re-deployment of internal resources to demand programs. For the South Middle Road TS (D-SS-01) project, where delays could have had customer impacts, Hydro One is utilizing external resources to ensure timely completion of the projects.

Project Specific Factors: The Wikwemikong Supply project (D-SS-01) is in a remote location with no road access. Project costs are expected to be higher than the Forecast due to outage restrictions, and transportation and material costs.

AMI 2.0 Project Implementation (D-SR-12): Hydro One is the first rural utility to undertake AMI 1.0 to AMI 2.0 migration in Ontario. As a result, there was limited information available to accurately estimate the level of complexity involved to safeguard customer billing accuracy during the replacement of the existing AMI 1.0 solution. Pre-deployment work consisting of preliminary scoping of system integration, deployment estimates and obtaining initial meter and network hardware estimates was completed in 2021. This was the basis for the total project forecast of $706M included in EB-2021-0110 with the goal to in-service $581M by 2027, and the remaining portion of the project to be completed by 2029. Detailed vendor estimates for meter and network hardware acquisition, meter and network hardware deployment, and systems integration were obtained in 2022. Scope optimization, vendor selection, meter and network hardware testing and initiation of IT implementation was completed in 2023. As the project developed over these years, the scope and total project cost matured and resulted in a

revised project estimate of $811M, an increase of $105M compared to the 2021 estimate. Addressing integration issues early and finalizing vendor contracts improved the overall project estimate. The project is still forecast to in-service $581M of work by 2027 and the remaining work by 2029. Hydro One continues to manage the risks pertaining to large scale meter installation and system integration, as well as opportunities to contain project costs.

DISTRIBUTION CAPITAL PERFORMANCE REPORT – 2024

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2024 in relation to the overall Distribution capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) delivered by Hydro One.

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal to the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL

Table 1 below presents a breakdown of the actual 2024 capital Distribution expenditures and ISA by OEB investment category and compares them against the Settlement Implementation Forecast. The primary focus of this report is on the Distribution System Access, System Renewal, and System Service categories. The Distribution General Plant category is discussed in the General Plant Capital Performance Report.

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

Table 1 - 2024 Distribution Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2024			In-Service Additions – 2024		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	$253.3	$355.2	$101.8	$254.5	$338.3	$83.8
System Renewal (Excl. AMI 2.0)	$287.0	$381.7	$94.7	$299.6	$380.4	$80.8
System Renewal (AMI 2.0 Only)	$69.5	$54.9	-$14.6	$69.5	$0.0	-$69.5
System Service	$157.2	$164.9	$7.7	$138.3	$142.0	$3.7
General Plant	$182.2	$158.8	-$23.4	$185.5	$144.6	-40.9
Total	**$949.2**	**$1,115.6**	**$166.4**	**$947.4**	**$1,005.3**	**$57.9**

In 2024, Hydro One's distribution capital expenditures were 18% above the OEB-approved amount and ISAs were 6% above the OEB-approved amount. Distribution capital expenditures and ISAs were higher due to System Access expenditures related to an increase in customer connection requests, more complex connection projects, and mandatory Joint Use and Relocation work (Externally Driven Work). In addition, accelerated System Renewal investments were completed to comply with polychlorinated biphenyls (PCBs) environmental regulations, respond to major weather events and complete pole replacements. Furthermore, expenditure variances at the OEB-category level were impacted by inflationary pressures including rising costs of goods, services, and labour. Hydro One has responded to these circumstances by reprioritizing and re-pacing its capital portfolio where it was possible to do so.

To partly offset these increases in the System Access category (i.e., customer driven), and the System Renewal category (i.e., compliance and demand driven), Hydro One made reductions in System Renewal (i.e. sustainment and replacement) and System Service (i.e., energy storage solutions and system capacity) categories. Further, lower General Plant and AMI 2.0 expenditures helped mitigate these increases. The OEB categories and associated variance explanations are summarized below.

[2] Does not include Hydro One affiliates.
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.257-58 (Table 25 and 26)

System Access: System Access capital expenditures and ISAs were higher than the OEB-approved amount by $101.8M and $83.8M respectively. These variances were primarily driven by a higher volume of New Load Connections and Service Upgrades (D-SA-02), including more complex large connection projects. As a result of their increased complexity and scope, these projects had higher design and estimation costs. In addition, there were more line relocations and third-party attachment requests. Higher expenditures in the above investments were partly offset by lower expenditures in metering sustainment (D-SA-04) due to lower volume.

System Renewal: System Renewal capital expenditures and ISAs were higher than the OEB-approved amount by $80.1M and $11.3M respectively. These variances were primarily driven by incremental expenditures in Distribution Lines Storm Damage & Trouble Call Response (D-SR-05) as a result of higher incident volumes, PCB equipment replacement (D-SR-06) to comply with environmental regulations, Wood pole program (D-SR-07) due to higher costs, and the Distribution Stations demand program (D-SR-01) driven by higher equipment failures. To mitigate these impacts, Hydro One reprioritized Submarine Cable Replacement (D-SR-09), Sustainment Initiatives (D-SR-10), and Wood pole programs (D-SR-07) volumes. The pace of the Advanced Meter Infrastructure (AMI 2.0) project (D-SR-12) was also adjusted as described further in Section 5 below.

System Service: Capital expenditures and ISAs were higher than the OEB-approved amount by $7.7M and $3.7M respectively. These variances were primarily driven by incremental expenditures in Demand Investments (D-SS-03) and Worst Performing Feeders (D-SS-05). Higher expenditures were partly offset by deferring work in Energy Storage Solutions (D-SS-04) related to grid-connected energy storage projects, and Load Growth projects (D-SS-01) related to system capability reinforcement.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM 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 reoccurs every year and the assets are largely 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 are not in-serviced until they are energized. Capital expenditure variances at the program-level are discussed in Section 4.0, and project-level variances are discussed in Section 5.0.

The projects and programs discussed in this report represent 99% of the 2024 actual ISA that is shown in Table 1 (for the System Access, System Renewal and System Service categories) and as such provide a very strong indication of the overall portfolio performance.

PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2024 greater than or equal to $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[4]:

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – For programs, material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2024 or earlier, to a later year.

The reasons for variances in individual projects and programs fall into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes that arise as a result of changing conditions, risks, and priorities that need to be addressed during execution. As risks materialize, plans

[4] This report's variance criteria conform with Hydro One's internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

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 without necessarily materially changing the in-service amount or affecting the overall volume of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors, as well as customer needs.

Work Definition

Work definition variances arise from the process of refining a project's scope, estimated budget and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or decreases in 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.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

4.0 PROGRAM PERFORMANCE

A large portion of Distribution's capital work program includes investments that are driven by demand and require action in a specified period as part of Hydro One's obligations under the Distribution System Code. While Hydro One 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 aiming to minimize the impacts of deferring planned investments that can introduce additional risks to the system in future years. Distribution Capital Program variances are summarized in Table 2 and further discussed below.

Table 21 - Distribution Program Summary

			2024 Dx Capital Expenditures ($M)			2024 Dx In-Service Additions ($M)			2024 Dx Units				Performance
OEB Category	Program Description		Forecast	Actual	Variance	Forecast	Actual	Variance	Unit Description	Forecast	Actual	Variance	Variance Category
System Access	D-SA-01	Joint Use and Relocations	30.7	45.1	14.3	31.2	38.8	7.7	None	n/a	n/a	n/a	Emergent Needs
	D-SA-02	New Load Connections and Upgrades	162.7	267.9	105.2	162.7	258.7	96.1	# of Connections, & Upgrades	21,178	24,832	3,654	Work Definition
	D-SA-04	Metering Sustainment	49.7	38.4	-11.3	49.7	38.8	-10.9	# of Meters Replaced	73,074	59,682	-13,392	Work Definition
System Renewal	D-SR-01	Distribution Stations Demand Capital Program	6.6	15.0	8.4	6.5	19.1	12.6	None	n/a	n/a	n/a	Emergent Needs
	D-SR-02	Mobile Unit Substation Program	4.5	3.2	-1.3	4.8	3.9	-0.9	# of MUS	2	1	-1	Reprioritization
	D-SR-03	Distribution Station Planned Component Replacement Program	4.4	5.2	0.8	4.6	4.9	0.3	# of Recloser & MUS Structures	139	103	-36	Execution Factors
	D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	113.8	168.5	54.7	113.8	168.3	54.5	None	n/a	n/a	n/a	Emergent Needs
	D-SR-06	Distribution Lines PCB Equipment Replacement Program	9.9	38.0	28.1	9.9	37.8	27.9	# of Transformer Replacements	1,504	2,903	1,399	Execution Factors
	D-SR-07	Pole Replacement	59.8	85.4	25.6	59.8	84.9	25.1	# of Pole Replacements	6,009	4962	-1,047	Execution Factors
	D-SR-07	Wood Pole Test and Treat	10.6	14.5	3.8	10.6	13.5	2.9	# of Poles Tested	101,597	116,682	15,085	Emergent Needs
	D-SR-07	Wood Pole Structural Refurbishment	6.6	7.5	0.9	6.6	7.5	0.9	# of Poles Refurbished	2,794	4,217	1,423	Emergent Needs
	D-SR-08	Distribution Lines Minor Component Replacement Program	15.3	14.0	-1.3	14.8	14.0	-0.8	# of Components Replaced	3,459	5,152	1,693	Work Definition
	D-SR-09	Submarine Cable Replacement Program	13.1	6.4	-6.7	13.1	6.2	-6.9	None	n/a	n/a	n/a	Reprioritization
	D-SR-10	Distribution Lines Sustainment Initiatives	8.4	4.4	(4.0)	8.3	4.9	-3.4	None	n/a	n/a	n/a	Reprioritization
System Service	D-SS-03	Demand Investments	14.1	24.0	9.9	14.0	19.4	5.5	None	n/a	n/a	n/a	Emergent Needs
	D-SS-04	Energy Storage Solutions	30.4	11.0	-19.4	28.1	9.7	-18.4	# of Battery Systems Installed	n/a	450	n/a	Reprioritization
	D-SS-05	Worst Performing Feeders	37.0	46.3	9.3	36.9	44.1	7.3	# of Devices	1,028	1,230	202	Work Definition
	D-SS-06	Stray Voltage	4.1	7.0	3.0	4.1	6.9	2.8	None	n/a	n/a	n/a	Emergent Needs

4.1 SYSTEM ACCESS PROGRAMS

The **Joint Use and Lines Relocations (D-SA-01)** program expenditures were above the forecast largely due to continued higher volumes of work, increased complexity in large line relocation projects, and the rising cost pressures outlined in Section 2.0 above. 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.

The **New Load Connection, Upgrades, Cancellations (D-SA-02)** program expenditures were above the forecast as the volume and scope of customer connections in 2024 materially exceeded historical levels. Hydro One facilitated a higher volume of large connection requests, which are more complex and costly to design and construct. In addition, expenditures for this program were affected by the general cost pressures outlined in Section 2.0 above. While there has been growth in both the volume and size of residential subdivision projects, the corresponding connection volumes will materialize in future periods. This is due to a timing lag as residential owners connect to the distribution system, over time.

The **Meter Infrastructure Sustainment (D-SA-04)** program expenditures were below the forecast largely due to a lower than forecast meter failures. As a result, fewer meters were replaced than initially projected.

4.2 SYSTEM RENEWAL PROGRAMS

The **Distribution Stations Demand Capital (D-SR-01)** program expenditures were above the forecast due to emergent needs driven by higher equipment failures. Costs in this category will vary depending on the type of failure, which can range from individual component replacements such as failed switches or electronic reclosers, to failed transformer replacements. This program was also affected by the rising cost pressures outlined in Section 2.0 above.

The **Mobile Unit Substations (D-SR-02)** program expenditures were below the forecast as it was reprioritized and deferred to future years. The 2024 expenditures and accomplishment were mostly carryover work from 2023.

The **Distribution Station Planned Component Replacement (D-SR-03)** program expenditures were in line with the forecast, however unit accomplishments were below forecast. Expenditures were higher due to technical constraints including unplanned yard extensions to accommodate required equipment, and unplanned battery/charger replacements.

The **Distribution Lines Trouble Call and Storm Damage Response (D-SR-05)** program expenditures were above the forecast due to a higher volume of storm damage, and trouble call related equipment failures and replacement requirement, in addition to higher general cost pressures outlined in Section 2.0. Major weather events including storms in April, June and November impacted program expenditures.

The **Distribution Lines PCB Equipment Replacement Program (D-SR-06)** program expenditures exceeded the forecast as Hydro One completed work to replace equipment containing PCBs to meet deadlines associated with environmental regulations. Replacement costs were also higher as certain associated equipment was replaced/upgraded at the same time, such as the pole in addition to the PCB-filled transformer.

The **Pole Sustainment Program (D-SR-07)** program contains three sub-programs: Pole Replacement, Wood Pole Test and Treat, and Wood Pole Structural Refurbishment. Pole Replacement expenditures were above forecast largely due to cost pressures as outlined in Section 2.0. As a result, some pole replacement work was deferred. To balance reliability risk associated with this deferral, Hydro One increased expenditures and accomplishments in both the Pole Test and Treat and Pole Refurbishment programs, resulting in lower refurbishment unit costs due to execution efficiencies.

The **Distribution Lines Minor Component Replacement Program (D-SR-08)** program expenditures were slightly below the forecast as a higher volume of less expensive components were replaced, such as crossarms and sentinel lights, resulting in higher accomplishments than forecast.

The **Submarine Cable Replacement Program (D-SR-09)** program expenditures were below the forecast due to work reprioritization to mitigate cost pressures in other programs. Severely degraded cables were prioritized and replaced to mitigate public safety risks.

The **Distribution Lines Sustainment Initiatives (D-SR-10)** program expenditures were below the forecast due to work reprioritization to mitigate emergent needs and cost pressures in other programs.

4.3 SYSTEM SERVICE PROGRAMS

The **Demand Investments (D-SS-03)** program expenditures were above the forecast due to higher than anticipated investment needs to address localized load growth and system constraints. This work includes minor distribution system modifications that are necessary and urgent to address system needs identified by customer power quality complaints, feeder studies and system impact assessments.

The **Energy Storage Solutions (D-SS-04)** program expenditures were below the forecast mostly due to reprioritization of work. Grid-scale battery energy storage projects were deferred to respond to emergent needs and cost pressures in other programs. Behind-the-meter residential battery storage for Customers Experiencing Long Interruption Duration (CELID) was prioritized to address localized reliability improvements.

The **Worst Performing Feeders Program (D-SS-05)** program expenditures were above the forecast to support the installation of a higher volume of Switches and Communicating

Fault Current Indicators (CFCI) devices on poor performance feeders. These investments were prioritized to improve reliability for customers and mitigate safety risks.

The **Stray Voltage (D-SS-06)** program expenditures were above the forecast due to higher requirements to address customer reported stray voltage and power quality issues.

5.0 PROJECT PERFORMANCE

The Distribution capital envelope is largely program-based, however, some large System Service investments are required to ensure the system can accommodate load growth. For these projects, Hydro One focuses on adherence to the total project cost rather than adherence to in-year expenditures

Table 3 summarizes the projects that met the performance criteria of a material 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 variance threshold. Hydro One continues to manage its capital expenditures through its investment planning process which prioritizes investments that respond to mandatory service obligations and mitigate the highest risk for the lowest cost. The balance of risks, system needs, and capital requirements that underpin a project deferral will continue to be monitored and reprioritized in conformance with the investment planning process.

The 19 projects in Table 3 below are either in a Planning, Deferred, Execution, or Completed phase. Of these 19 projects 3 did not meet the performance definitions in Section 3.1 above, 2 were reprioritized or cancelled primarily due to load growth materializing at a slower than forecast pace. Another 5 were reprioritized to accommodate projects or programs requiring emergent needs. Variance explanations for the remaining 9 projects have been provided where required using the criteria outlined in Section 3.1 above.

Table 3 - Distribution Project Summary

			2024 Dx Capital Expenditures ($M)		2024 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[5]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance	Variance Category
Pointe Au Baril Transformer Replacement	Execution	D-SR-04	2.0	0.7	4.1	3.6	4.1	3.5	-0.6	2024	2024	0	Not Applicable
Lindsay M7 Line Upgrade	Execution	D-SR-10	5.0	7.5	11.0	10.8	11.0	11.1	0.1	2024	2024	0	Not Applicable
Norfolk M3 Tillsonburg M10 Tie Relocation	Planning	D-SR-10	3.2	0.0	3.6	0.0	3.6	3.6	0.0	2024	2028	4	Reprioritization
AMI 2.0	Execution	D-SR-12	69.5	54.9	111.2	0.0	705.6	820.0	114.4	2029	2029	0	Execution Factors
Barrie TS - Construct new feeders	Execution	D-SS-01	2.8	6.4	8.4	0.0	8.4	11.0	2.6	2024	2025	1	Execution Factors
Brockville 44kV Load Growth	Planning	D-SS-01	4.5	0.0	9.9	0.0	9.9	9.9	0.0	2024	2030	6	Reprioritization
Caledonia TS New Feeder Positions	Execution	D-SS-01	3.0	3.4	3.0	0.0	3.0	5.9	2.9	2024	2025	1	Work definition
Curve Inn DS New Feeder	Execution	D-SS-01	0.0	0.6	0.0	4.2	5.6	4.2	-1.4	2023	2024	1	Execution Factors
Greens Corner and Vittoria PDS	Planning	D-SS-01	2.0	0.0	3.0	0.0	3.0	3.0	0.0	2024	2029	5	Reprioritization
Kirkland Lake Voltage Conversion - Part 3	Planning	D-SS-01	3.1	0.3	3.3	0.0	3.3	3.3	0.0	2024	2026	2	Reprioritization
Listowel Load Relief - Load Growth	Planning	D-SS-01	3.7	0.0	4.3	0.0	4.3	4.3	0.0	2024	2028	4	Execution Factors
Manotick DS Add F3 Feeder Load Growth	Cancelled	D-SS-01	2.8	0.0	3.0	0.0	3.0	0.0	-3.0	2024	n/a	n/a	Not Applicable
Saugeen Shores DS and Port Elgin Load Growth	Planning	D-SS-01	2.0	0.1	5.4	0.0	5.4	5.4	0.0	2024	2026	2	Reprioritization
South Middle Road TS DESN1 Feeder Development	Execution	D-SS-01	1.2	3.2	0.0	21.4	130.5	141.4	10.9	2025	2025	0	Not Applicable
Stouffville 10th Line DS to Ringwood DS 27.6kV Tie	Execution	D-SS-01	0.7	2.9	1.5	3.9	1.5	3.9	2.4	2024	2024	0	Emergent Needs
Wikwemikong Supply - Station & Line Work	Execution	D-SS-01	0.0	5.1	0.0	13.8	6.0	14.2	8.2	2023	2024	1	Execution Factors
Muskoka TS M1-M5 New Tie Line	Planning	D-SS-02	10.1	0.1	10.2	0.0	10.2	10.2	0.0	2024	2030	6	Reprioritization
Orillia TS M2-M6 New Tie Line	Execution	D-SS-02	4.1	5.5	4.2	5.8	4.2	5.8	1.6	2024	2024	0	Work Definition
Dryden Rural DS F2 1ph to 3ph Conversion	Execution	D-SS-NEW	0.0	4.2	0.0	4.5	0.0	4.8	4.8	0	2024	n/a	Emergent Needs

[5] Phases: Planning, Execution, Complete, Cancelled, or Deferred.

Several factors impacted project costs and schedule:

Vendor Estimates and Municipal Delays: Caledonia TS New Feeder and Feeder Positions (D-SS-01), and Listowel Load Relief (D-SS-01) projects are all in early stages of development. The Caledonia projects experienced delays in obtaining detailed estimates from vendors. The Listowel project experienced delays in approvals from the local municipality. Coordination with other municipal work resulted in cost savings for the Curve Inn DS New Feeder (D-SS-01) project while accommodating a longer in-servicing schedule.

Scope Modifications During Detailed Design: Design adjustments to accommodate community requests and additional requirements uncovered during detailed design increased project scope for the Wikiwemikong Supply – Station & Line Work (D-SS-01), Barrie TS – New Feeders (D-SS-01), and Orillia TS M2-M6 New Tie Line projects (D-SS-02).

Project Changes to Address Emerging Reliability Constraints: Areas such as Wabigoon First Nation and the Town of Stouffville experienced higher than anticipated load growth and potential reliability constraints. Hydro One addressed these constraints by prioritizing and adjusting the scopes for Stouffville 10th Line DS to Ringwood DS 27.6 kV Tie (D-SS-01) and Dryden Rural DS F2 1ph to 3ph Conversion (D-SS-NEW) projects.

AMI 2.0 Project Implementation (D-SR-12): Total costs in the AMI 2.0 project have increased primarily due to higher than estimated IT integration, foundational planning and program management activities (e.g., contracting, IT assessments and IT development work) associated with complexities moving from the AMI 1.0 to the AMI 2.0 platform. As a result of these challenges, the meter and network deployment pilot has been rescheduled to 2025. Hydro One remains focused on managing the AMI 2.0 capital envelope in the current rate period and identifying efficiencies to mitigate the cost variances and schedule delays experienced to date.

DISTRIBUTION CAPITAL PERFORMANCE REPORT – 2025

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2025 in relation to the overall Distribution capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) delivered by Hydro One.

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal to the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL

Table 1 below presents a breakdown of the actual 2025 capital Distribution expenditures and ISA by OEB investment category and compares them to the OEB-approved values. The primary focus of this report is on the Distribution System Access, System Renewal, and System Service categories. The Distribution General Plant category is discussed in the General Plant Capital Performance Report.

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

Table 1 - 2025 Distribution Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2025			In-Service Additions – 2025		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	$238.9	$340.6	$101.7	$239.4	$333.7	$94.3
System Renewal (Excl. AMI 2.0)	$ 280.6	$422.3	$141.7	$289.1	$419.7	$130.6
System Renewal (AMI 2.0 Only)	$158.4	$94.6	-$63.8	$158.4	$146.7	-$11.7
System Service	$ 212.6	$108.4	-$104.2	$232.6	$155.7	-$77.0
General Plant	$149.5	$118.7	-$30.7	$193.7	$195.2	$1.6
Total	**$1,040.0**	**$1,084.6**	**$44.6**	**$1,113.1**	**$1,250.9**	**$137.8**

In 2025, Hydro One's distribution capital expenditures were 4% above the OEB-approved amount and ISAs were 12% above the OEB-approved amount. Distribution capital expenditures and ISAs were higher due to System Access expenditures related to increased customer connection requests, more complex connection projects, and mandatory Joint Use and Relocation work (Externally Driven Work). In addition, higher System Renewal investments were required to respond to major weather events predominantly the March 2025 Ice Storm and polychlorinated biphenyls (PCBs) equipment replacement required to meet deadlines associated with environmental regulations. Furthermore, expenditure variances at the OEB-category level were impacted by inflationary pressures, including rising costs of goods, services, and labour. Hydro One has responded to these circumstances by reprioritizing and re-pacing its capital portfolio where it was possible to do so.

To partly offset these increases in the System Access category (i.e., customer-driven), and the System Renewal category (i.e., emergency, demand-driven and compliance), Hydro One made reductions in certain System Renewal (i.e., sustainment and replacement) and System Service (i.e., energy storage solutions, system capacity and feeder modernization) programs. Further, lower General Plant and AMI 2.0 expenditures

[2] Does not include Hydro One affiliates.
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.257-58 (Table 25 and 26)

helped mitigate these increases. The OEB categories and associated variance explanations are summarized below.

System Access: System Access capital expenditures and ISAs were higher than the OEB-approved amount by $101.7M and $94.3M, respectively. These variances were primarily driven by higher expenditures in New Load Connections and Upgrades (D-SA-02), reflecting a greater number of large connection requests, and increased project scope and complexity. In addition, Joint Use and Lines Relocations (D-SA-01) expenditures were above the forecast due to sustained higher externally driven work volumes, including more complex line relocation projects and third-party attachment requests. Meter Infrastructure Sustainment (D-SA-04) did not have a material impact on the System Access category variance.

System Renewal: System Renewal capital expenditures and ISAs were higher than the OEB-approved amount by $77.9M and $118.9M, respectively. These variances were primarily driven by higher expenditures in Distribution Lines Trouble Call and Storm Damage Response (D-SR-05), predominantly due to the March 2025 Ice Storm; Distribution Lines PCB Equipment Replacement (D-SR-06), to meet deadlines associated with environmental regulations; and Distribution Stations Demand Capital (D-SR-01), due to emergent needs driven by higher equipment failures. To help mitigate these impacts, Hydro One reprioritized the funding of specific planned System Renewal work, including Pole Sustainment (D-SR-07), Station Renewal (D-SR-04), Submarine Cable Replacement (D-SR-09), Distribution Lines Sustainment Initiatives (D-SR-10), and other planned station component replacement work. Within Distribution Lines Minor Component Replacement (D-SR-08), overall expenditures were below forecast; with most programs having lower accomplishments with the exception of sentinel light-related activities that were higher due to PCB compliance requirements. The Advanced Meter Infrastructure (AMI 2.0) project (D-SR-12) also had lower expenditures and ISAs in 2025 as the project pacing was adjusted, as discussed further in Section 5 below.

System Service: System Service capital expenditures and ISAs were lower than the OEB-approved amount by $104.2M and $77.0M, respectively. These variances were primarily driven by work reprioritization in Energy Storage Solutions (D-SS-04), Worst Performing Feeders (D-SS-05), and Load Growth Projects (D-SS-01), reflecting reductions in planned energy storage, feeder modernization, and system capacity work. These reductions were partly offset by higher expenditures in Demand Investments (D-SS-03), driven by localized load growth and system constraints.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM 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 reoccurs every year and the assets are largely 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 are not in-serviced until they are energized. Capital expenditure variances at the program-level are discussed in Section 4.0, and project-level variances are discussed in Section 5.0.

The projects and programs discussed in this report represent 92% of the 2025 actual ISA that is shown in Table 1 (for the System Access, System Renewal and System Service categories) and as such provide a very strong indication of the overall portfolio performance.

Performance Definitions

Projects and programs with planned or actual ISA in 2025 greater than or equal to $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[4]:

[4] This report's variance criteria conform with Hydro One's internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – For programs, material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2025 or earlier, to a later year.

The reasons for variances in individual projects and programs fall into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes 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 without necessarily materially changing the in-service amount or affecting the overall volume of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors, as well as customer needs.

Work Definition

Work definition variances arise from the process of refining a project's scope, estimated budget and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or

decreases in 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.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

4.0 PROGRAM PERFORMANCE

A large portion of Distribution's capital work program includes investments that are driven by demand and require action in a specified period as part of Hydro One's obligations under the Distribution System Code. While Hydro One 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 reprioritization process that provides the flexibility necessary to reprioritize investments to respond to fluctuations in emergent work while aiming to minimize the impacts of deferring planned investments that can introduce additional risks to the system in future years. Distribution Capital Program variances are summarized in Table 2 and further discussed below.

Table 2 - Distribution Program Summary[5]

			2025 Dx Capital Expenditures ($M)			2025 Dx In-Service Additions ($M)			2025 Dx Units				Performance
OEB Category	**Program Description**		**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Unit Description**	**Forecast**	**Actual**	**Variance**	**Variance Category**
System Access	D-SA-01	Joint Use and Relocations	28.5	40.5	11.9	28.7	33.3	4.6	None	n/a	n/a	n/a	Emergent Needs
	D-SA-02	New Load Connections, Upgrades and Cancellations	166.8	252.3	85.5	166.8	251.1	84.2	# of Connections & Upgrades	21,317	20,353	-964	Work Definition
	D-SA-04	Metering Sustainment	43.4	42.6	-0.8	43.6	42.8	-0.8	# of Meters Replaced	54,916	54,399	-517	Not Applicable
System Renewal	D-SR-01	Distribution Stations Demand Capital Program	6.7	12.0	5.2	6.7	13.4	6.7	None	n/a	n/a	n/a	Emergent Needs
	D-SR-02	Mobile Unit Substation Program	3.3	1.4	-1.8	4.1	4.1	0.1	# of MUS	1	1	0	Reprioritization
	D-SR-03	Distribution Station Planned Component Replacement Program	4.1	0.6	-3.5	4.3	3.2	-1.2	# of Recloser & MUS Structures	109	219	110	Reprioritization
	D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	116.1	332.5	216.5	116.1	329.9	213.8	None	n/a	n/a	n/a	Emergent Needs
	D-SR-06	Distribution Lines PCB Equipment Replacement Program	10.0	23.5	13.6	10.0	23.7	13.8	# of Transformer Replacements	1,476	1,735	259	Execution Factors
	D-SR-07	Pole Sustainment	60.5	16.0	-44.5	60.5	16.4	-44.1	# of Pole Replacements	5,976	1,034	-4,942	Reprioritization
	D-SR-07	Wood Pole Test and Treat	10.8	0.5	-10.3	10.8	0.4	-10.4	# of Poles Tested	101,598	3,366	-98,232	Reprioritization
	D-SR-07	Wood Pole Structural Refurbishment	6.6	-0.2	-6.9	6.7	-0.2	-6.9	# of Poles Refurbished	2,785	0	-2,785	Reprioritization
	D-SR-08	Distribution Lines Minor Component Replacement Program	14.2	11.1	-3.2	14.7	11.0	-3.7	# of Components Replaced	3,275	8,061	4,786	Work Definition
	D-SR-09	Submarine Cable Replacement Program	13.4	1.2	-12.2	13.3	1.5	-11.9	None	n/a	n/a	n/a	Reprioritization
	D-SR-10	Distribution Lines Sustainment Initiatives	8.7	5.5	-3.2	8.7	5.2	-3.5	None	n/a	n/a	n/a	Reprioritization
System Service	D-SS-03	Demand System Modifications	14.4	27.2	12.8	14.2	24.7	10.5	None	n/a	n/a	n/a	Emergent Needs
	D-SS-04	Energy Storage Solutions	29.5	7.9	-21.6	21.0	3.0	-18.0	# of Battery Systems Installed	n/a	75	n/a	Reprioritization
	D-SS-05	Worst Performing Feeders	37.7	14.4	-23.3	37.6	13.9	-23.7	# of Devices	1,296	1,078	-218	Reprioritization
	D-SS-06	Power Quality and Stray Voltage	4.2	5.0	0.8	4.2	5.0	0.8	None	n/a	n/a	n/a	Emergent Needs

[5] Figures presented in the tables may not sum to the totals shown due to rounding.

Witness: Gianni Difilippo

4.1 SYSTEM ACCESS PROGRAMS

The **Joint Use and Lines Relocations (D-SA-01)** program expenditures were above forecast primarily due to sustained higher work volumes, increased complexity associated with large line relocation projects, and the broader cost pressures described in Section 2.0. This work is largely externally driven and is required for Hydro One to meet its contractual obligations to third parties under Joint Use agreements and to maintain compliance with the requirements of Hydro One's distributor licence.

The **New Load Connection, Upgrades, Cancellations (D-SA-02)** program expenditures were above forecast due to a combination of a greater number of large connection requests, increased project scope and complexity, and the broader cost pressures outlined in Section 2.0. Although overall program volumes were lower than forecast, this was mainly attributable to lower subdivision connection volumes in 2025. These subdivision-related volumes are expected to materialize in future periods due to the timing lag between subdivision development and individual residential customers connecting to the distribution system. Excluding this subdivision timing impact, customer connection and upgrade activity was higher than forecast, with a greater proportion of large and complex requests that are more costly to design, estimate, and construct.

The **Metering Sustainment (D-SA-04)** program expenditures were largely in line with the forecast. Program activity was consistent with planned meter sustainment requirements, and the slight variance reflects normal fluctuations in meter replacement needs and execution timing.

4.2 SYSTEM RENEWAL PROGRAMS

The **Distribution Stations Demand Capital (D-SR-01)** program expenditures were above forecast due to emergent needs driven by higher equipment failures. Expenditures under this category vary based on the nature and severity of the equipment failure, which can range from individual component replacements, such as failed switches or electronic reclosers, to more significant transformer replacements. The program was also impacted by the broader cost pressures outlined in Section 2.0.

The **Mobile Unit Substations (MUS) (D-SR-02)** program expenditures were below the forecast due to work reprioritization and the deferral of planned work to future years. In-year expenditures and in-service additions primarily reflected carryover work from 2024.

The **Distribution Station Planned Component Replacement (D-SR-03)** program expenditures were below the forecast due to work reprioritization. As part of Hydro One's portfolio management process, planned station component replacement work was adjusted to prioritize higher-risk mandatory, emergent, and customer-driven work within the overall capital envelope. Replacement work under this planned program will continue to be assessed based on asset condition, safety, reliability risk, and execution requirement. Most of the component replacements were hydraulic reclosers which are less expensive compared to other more expensive components such as MUS structures and switches.

The **Distribution Lines Trouble Call and Storm Damage Response (D-SR-05)** program expenditures were above the forecast predominantly due to the March 2025 Ice Storm. Beginning on March 29, 2025, severe freezing rain and significant ice accumulation caused extensive damage across Hydro One's distribution system, particularly in the Southern, Eastern, and Central regions. The event resulted in approximately 1.2 million service interruptions and impacted over 600,000 customers, representing approximately 42% of Hydro One's customer base. The storm caused substantial damage to distribution assets requiring a significant restoration and rebuild response by Hydro One crews, contractors, and other external crews. While the program also continued to address normal-course trouble calls, equipment failures, and other storm events, the March 2025 Ice Storm was the predominant driver of the variance due to the scale of damage, restoration resources required and associated capital replacement work. The program was also impacted by the broader cost pressures outlined in Section 2.0, including inflationary pressures and rising costs of goods, services, and labour.

The **Distribution Lines PCB Equipment Replacement Program (D-SR-06)** program expenditures exceeded the forecast as Hydro One continued to complete work to replace

equipment containing PCBs to meet deadlines associated with environmental regulations. Replacement costs were also higher where related equipment was replaced or upgraded at the same time to support safe, compliant, and efficient execution on the distribution system, such as poles replaced in conjunction with PCB-filled transformers.

The **Pole Sustainment Program (D-SR-07)** program contains three sub-programs: Pole Replacement, Wood Pole Test and Treat, and Wood Pole Structural Refurbishment. Program expenditures and accomplishments across the three sub-programs were below forecast due to work reprioritization. In 2025, higher overall Distribution capital demand, including mandatory customer-driven work, time-sensitive storm response, and compliance-related work, required Hydro One to reprioritize planned pole sustainment work within the overall capital envelope and allocate resources to higher-priority demand programs.

The **Distribution Lines Minor Component Replacement Program (D-SR-08)** program expenditures were below forecast due to work reprioritization. Although overall expenditures were below forecast, accomplishments were higher than forecast because the work completed included a higher volume of lower-cost sentinel light-related activities. Sentinel light work increased in 2025 as the program shifted to proactive replacement of older mercury vapour fixtures of a vintage associated with PCB content. Replacing these older fixtures supported PCB compliance and remediation requirements to meet deadlines associated with environmental regulations.

The **Submarine Cable Replacement Program (D-SR-09)** program expenditures were below forecast due to work reprioritization to mitigate emergent needs and cost pressures in other programs. Within the reduced level of spending, Hydro One prioritized work on the highest-risk damaged or exposed submarine cables to mitigate public safety risks and maintain reliability.

The **Distribution Lines Sustainment Initiatives (D-SR-10)** program expenditures were below forecast due to work reprioritization to address emergent needs and cost pressures in other programs.

4.3 SYSTEM SERVICE PROGRAMS

The **Demand System Modifications (D-SS-03)** program expenditures were above the forecast due to higher than anticipated investment needs to address localized load growth and system constraints. This work includes minor distribution system modifications that are necessary and urgent to address system needs identified through customer power quality complaints, feeder studies, and system impact assessments.

The **Energy Storage Solutions (D-SS-04)** program expenditures were below the forecast due to work reprioritization. Grid-scale battery energy storage initiatives were largely deferred to respond to emergent needs and cost pressures in other programs. However, development of one Grid Scale project at La Croix First Nation is currently underway. Behind-the-meter residential battery storage for Customers Experiencing Long Interruption Duration (CELID) was also reprioritized. However, Hydro One successfully deployed 75 residential battery storage installations in 2025 and began delivering benefits to participating customers.

The **Worst Performing Feeders Program (D-SS-05)** program expenditures were below the forecast due to work reprioritization to help offset continued pressures from demand-driven and emergency work. Communicating Fault Current Indicator (CFCI) work, which supports fault detection and location, continued and was largely in line with the forecast. Switch-related feeder modernization work, which supports feeder sectionalization and load transfer capability for faster customer power restoration, was reprioritized.

The **Stray Voltage (D-SS-06)** program expenditures were above the forecast due to higher than anticipated requirements to address customer-reported stray voltage and power quality issues.

5.0 PROJECT PERFORMANCE

The Distribution capital envelope is largely program-based; however, some project-based investments are required. For these projects, Hydro One focuses on adherence to the total project cost rather than adherence to in-year expenditures.

Table 3 summarizes the projects that met the performance criteria of a material 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 variance threshold. Hydro One continues to manage its capital expenditures through its investment planning process which prioritizes investments that respond to mandatory service obligations and mitigate the highest risk for the lowest cost. The balance of risks, system needs, and capital requirements that underpin a project deferral will continue to be monitored and reprioritized in conformance with the investment planning process.

The 15 projects in Table 3 below are either in a Planning, Deferred, Execution, or Completed phase. Of these 15 projects, two did not meet the performance definitions in Section 3.1 above, two were reprioritized primarily because load growth materialized more slowly than forecast, and three were reprioritized to accommodate projects or programs requiring emergent needs. Variance explanations for the remaining eight projects have been provided where required using the criteria outlined in Section 3.1 above.

Table 3 - Distribution Project Summary

			2025 Dx Capital Expenditures ($M)		2025 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[6]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Variance Category**
Wallaceburg DS Relocation	Execution	D-SA-Other	0.0	3.7	0.0	5.5	0.0	5.6	5.6	N/A	2025	N/A	Emergent Needs
Vanastra DS Padmount Transformers	Execution	D-SR-04	0.0	2.0	0.0	6.4	4.3	6.6	2.3	2023	2025	2	Execution Factors
Dymond TS M3 Rebuild - Stage 2	Execution	D-SR-10	2.3	3.1	6.8	0.0	6.8	6.7	-0.1	2025	2026	1	Execution Factors
Enfield TS M4 44KV Line Relocation	Execution	D-SR-10	0.0	5.2	0.0	0.0	0.0	28.0	28.0	N/A	2026	N/A	Emergent Needs
Minden TS M2 Muskoka TS M4 Relocate Tie	Deferred	D-SR-10	4.3	0.0	4.4	0.0	4.4	4.6	0.3	2025	2031	6	Reprioritization
AMI 2.0	Execution	D-SR-12	158.4	94.6	158.4	146.7	705.6	799.4	93.8	2029	2029	0	Execution Factors
Brant TS M22 Load Relief	Deferred	D-SS-01	3.5	0.0	3.9	0.0	3.9	0.0	-3.9	2025	2033	8	Reprioritization
Chesterville M1 Load Growth	Deferred	D-SS-01	2.9	0.0	3.3	0.0	3.3	3.3	0.0	2025	2033	8	Reprioritization
Dickenson Rd DS F2 + Mount Hope DS Load Relief	Execution	D-SS-01	0.0	3.7	0.0	3.7	1.5	3.7	2.2	2024	2025	1	Execution Factors
Leamington Area DESN5 Feeder Development	Planning	D-SS-01	12.3	0.0	0.0	0.0	51.2	32.2	-19.0	2027	2032	5	Work Definition
South Middle Road TS DESN1 Feeder Development	Execution	D-SS-01	0.8	0.7	18.1	22.3	130.5	141.3	10.8	2025	2025	0	Not a Material Variance
South Middle Road TS DESN2 Feeder Development	Execution	D-SS-01	6.3	17.0	74.1	71.3	74.2	71.3	-2.8	2025	2025	0	Not a Material Variance
Midhurst TS M4-M9 44kV Tie-line	Deferred	D-SS-02	5.4	0.0	5.5	0.0	5.5	6.8	1.3	2025	2031	6	Reprioritization
Stayner TS M2 Tie Line	Deferred	D-SS-02	0.0	0.0	0.0	0.0	4.3	6.0	1.7	2025	2031	6	Reprioritization
ADMS Upgrade - DC 206	Execution	D-SS-Other	0.0	6.2	0.0	0.0	0.0	42.7	42.7	N/A	2028	N/A	Emergent Needs

[6] Phases: Planning, Execution, Complete, Cancelled, or Deferred.

Witness: Gianni Difilippo

Several factors impacted project costs and schedule:

Transmission Driven Emergent Needs: The unanticipated acceleration of transmission projects triggered the relocation of distribution assets. This resulted in distribution line and station relocation projects including Wallaceburg DS Relocation (D-SA-Other), and Enfield TS M4 44kV line relocation (D-SR-10). Hydro One deferred the completion of Leamington Area DESN5 Feeder Development (D-SS-01) to align with Transmission lines and stations investments in the area which must be in place to supply the downstream feeders.

Scope and Schedule Alignment During Detailed Design: As projects moved from early planning stages to detailed design, several incremental scope components leading to increased costs or schedule delays emerged. Vanastra DS Padmount Transformers (D-SR-04) required excess soil remediation and transformer pad re-leveling which resulted in additional efforts and increased construction timeline. Acquiring outstanding easements for Dickenson Rd DS F2 and Mount Hope DS Load Relief (D-SS-01) resulted in schedule delays. Hydro One delayed the Dymond TS M3 Rebuild - Stage 2 (D-SR-10) and brought forward the ADMS Upgrade (D-SS-Other) to address several end-of-life assets in a coordinated manner. This eliminated the need for discrete Outage Response Management System and Distribution Management System upgrades.

AMI 2.0 Project Implementation (D-SR-12): Total costs for the AMI 2.0 project are forecast to be higher than those approved in EB-2021-0110, primarily due to higher-than-estimated IT integration, foundational planning, and program management activities, including contracting, IT assessments, and IT development work associated with the complexities of transitioning from the AMI 1.0 platform to AMI 2.0. As a result of these challenges, the meter and network deployment pilot was delayed to 2025. Consequently, the commencement of mass meter deployment was deferred until the end of 2025, resulting in lower-than-planned ISA amounts for 2025. The total forecast cost estimate reflects updated vendor pricing, refined planning assumptions, actual expenditures incurred from 2021 through 2025, and forecast costs.

SECTION 3.9- ATTACHMENT 5 - DISTRIBUTION CAPITAL PERFORMANCE SUMMARY – 2026 AND 2027

1.0 CAPITAL PERFORMANCE SUMMARY OVERVIEW

1.1 BACKGROUND

This Capital Performance Summary provides an overview of Hydro One's forecast performance for 2026 and 2027 in relation to individual projects and programs. It addresses both forecast capital expenditures and in-service additions (ISA).

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal to the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Summary.

2.0 PERFORMANCE AT THE PROJECT AND PROGRAM 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 reoccurs every year and the assets are largely 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 are not in-serviced until they are energized. Capital expenditure variances at the program-level are discussed in Section 3.0, and project-level variances are discussed in Section 4.0.

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

The projects and programs discussed in this report represent more than 90% of the 2026 and 2027 planned ISA.

Performance Definitions

Projects and programs with planned or actual ISA in 2026 and 2027 greater than or equal to $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[2]:

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – For programs, material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from either 2026 or 2027, or earlier, to a later year.

The reasons for variances in individual projects and programs fall into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

[2] This report's variance criteria conform with Hydro One's internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes 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 without necessarily materially changing the in-service amount or affecting the overall volume of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors, as well as customer needs.

Work Definition

Work definition variances arise from the process of refining a project's scope, estimated budget and schedule as the project moves from the planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or decreases in 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.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

3.0 PROGRAM PERFORMANCE FORECAST

A large portion of Distribution's capital work program includes investments that are driven by demand and require action in a specified period as part of Hydro One's obligations under the Distribution System Code. While Hydro One 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. Table 1 and Table 2 below provide the forecast in-year expenditures, in-service additions, and accomplishments with accompanying variance categories for 2026 and 2027 respectively.

Table 1 - 2026 Distribution Program Forecast Summary[3]

			2026 Dx Capital Expenditures ($M)			2026 Dx In-Service Additions ($M)			2026 Dx Units				Performance
OEB Category	Program Description		Forecast	Latest Forecast	Variance	Forecast	Latest Forecast	Variance	Unit Description	Forecast	Latest Forecast	Variance	Variance Category
System Access	D-SA-01	Joint Use and Relocations	28.1	48.6	20.5	28.2	61.0	32.8	None	n/a	n/a	n/a	Emergent Needs
	D-SA-02	New Load Connections and Upgrades	171.1	255.9	84.8	171.0	268.3	97.3	# of Connections, & Upgrades	21,432	23,804	2,372	Work Definition
	D-SA-03	Connecting Distributed Energy Resources	1.5	3.2	1.7	1.5	4.0	2.5	# of Generation Connections	200	1,412	1,212	Emergent Needs
	D-SA-04	Metering Sustainment	31.3	33.1	1.8	31.3	31.7	0.4	# of Meters Replaced	29764	33,386	3,622	Not a Material Variance
System Renewal	D-SR-01	Distribution Stations Demand Capital Program	6.9	13.9	7.1	6.8	21.7	14.9	None	n/a	n/a	n/a	Reprioritization
	D-SR-02	Mobile Unit Substation Program	3.3	1.9	-1.5	3.3	1.1	-2.1	# of MUS	1	0	-1	Reprioritization
	D-SR-03	Distribution Station Planned Component Replacement Program	3.6	-	-3.6	3.9	1.5	-2.4	# of Recloser & MUS Structures	68	0	-68	Reprioritization
	D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	118.4	164.5	46.1	118.4	164.5	46.1	None	n/a	n/a	n/a	Emergent Needs
	D-SR-07	Pole Replacement	62.0	-	-62.0	62.0	0.1	-61.9	# of Pole Replacements	5918	0	-5,918	Reprioritization
	D-SR-07	Wood Pole Test and Treat	11.1	-	-11.1	11.1	0.6	-10.5	# of Poles Tested	100000	0	-100,000	Reprioritization
	D-SR-07	Wood Pole Structural Refurbishment	6.8	-	-6.8	6.8	-	-6.8	# of Poles Refurbished	2777	0	-2,777	Reprioritization
	D-SR-08	Distribution Lines Minor Component Replacement Program	9.0	1.6	-7.4	10.7	1.6	-9.1	# of Components Replaced	2982	1,750	-1,232	Reprioritization
	D-SR-09	Submarine Cable Replacement Program	13.6	-	-13.6	13.6	-	-13.6	None	n/a	n/a	n/a	Reprioritization
	D-SR-10	Distribution Lines Sustainment Initiatives	9.2	8.9	-0.3	9.1	11.2	2.2	None	n/a	n/a	n/a	Execution Factors
Demand Investments	D-SS-03	Demand Investments	14.6	21.4	6.8	14.5	18.5	4.1	None	n/a	n/a	n/a	Emergent Needs
	D-SS-04	Energy Storage Solutions (Residential BESS)	11.7	0.0	-11.7	11.6	0.1	-11.5	# of Battery Systems Installed	n/a	0	n/a	Reprioritization
	D-SS-05	Worst Performing Feeders	39.3	7.0	-32.3	39.0	21.0	-18.0	# of Devices	1323	1100	-223	Reprioritization
	D-SS-06	Power Quality and Stray Voltage	4.2	6.4	2.2	4.2	6.4	2.2	None	n/a	n/a	n/a	Emergent Needs

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

Witness: Paul Ankrett; Peter Faltaous; Spencer Gill

Table 2 - 2027 Distribution Program Forecast Summary

			2027 Dx Capital Expenditures ($M)			2027 Dx In-Service Additions ($M)			2027 Dx Units				Performance
OEB Category	Program Description		Forecast	Latest Forecast	Variance	Forecast	Latest Forecast	Variance	Unit Description	Forecast	Latest Forecast	Variance	Variance Category
System Access	D-SA-01	Joint Use and Relocations	29.1	49.7	20.6	29.2	59.4	30.2	None	n/a	n/a	n/a	Emergent Needs
	D-SA-02	New Load Connections and Upgrades	175.4	258.5	83.1	175.4	271.2	95.8	# of Connections, & Upgrades	21,548	23,588	2,040	Work Definition
	D-SA-03	Connecting Distributed Energy Resources	1.5	3.2	1.7	1.5	3.3	1.8	# of Generation Connections	196	1,412	1216	Emergent Needs
	D-SA-04	Metering Sustainment	18.9	20.7	1.8	18.9	19.6	0.7	# of Meters Replaced	10975	14,227	3,252	Not a Material Variance
System Renewal	D-SR-01	Distribution Stations Demand Capital Program	7.0	14.2	7.2	6.9	6.6	-0.4	None	n/a	n/a	n/a	Not a Material Variance
	D-SR-02	Mobile Unit Substation Program	3.4	2.1	-1.3	3.4	2.8	-0.6	# of MUS	1	1	0	Not a Material Variance
	D-SR-03	Distribution Station Planned Component Replacement Program	3.6	-	-3.6	3.6	0.5	-3.1	# of Recloser & MUS Structures	67	0	-67	Reprioritization
	D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	120.8	165.6	44.8	120.8	165.7	44.9	None	n/a	n/a	n/a	Emergent Needs
	D-SR-07	Pole Replacement	62.9	-	-62.9	62.9	0.1	-62.8	# of Pole Replacements	5917	0	-5,917	Reprioritization
	D-SR-07	Wood Pole Test and Treat	11.3	-	-11.3	11.3	0.6	-10.7	# of Poles Tested	99999	0	-99,999	Reprioritization
	D-SR-07	Wood Pole Structural Refurbishment	6.9	-	-6.9	6.9	-	-6.9	# of Poles Refurbished	2777	0	-2,777	Reprioritization
	D-SR-08	Distribution Lines Minor Component Replacement Program	7.5	1.7	-5.9	8.1	1.7	-6.4	# of Components Replaced	2817	1,750	-1,067	Reprioritization
	D-SR-09	Submarine Cable Replacement Program	13.9	-	-13.9	13.9	-	-13.9	None	n/a	n/a	n/a	Reprioritization
	D-SR-10	Distribution Lines Sustainment Initiatives	9.6	6.4	-3.2	9.5	9.0	-0.5	None	n/a	n/a	n/a	Reprioritization
System Service	D-SS-03	Demand Investments	15.0	21.9	6.9	14.7	21.0	6.2	None	n/a	n/a	n/a	Emergent Needs
	D-SS-04	Energy Storage Solutions (Residential BESS)	11.0	0.0	-11.0	11.5	0.0	-11.5	# of Battery Systems Installed	n/a	0	n/a	Reprioritization
	D-SS-05	Worst Performing Feeders	40.1	7.1	-33.0	39.9	21.5	-18.4	# of Devices	1344	1039	-305	Reprioritization
	D-SS-06	Power Quality and Stray Voltage	4.3	6.2	1.9	4.3	6.2	1.9	None	n/a	n/a	n/a	Emergent Needs

4.0 PROJECT PERFORMANCE FORECAST

A significant portion of the distribution capital envelope is program-based. However, there are some System Renewal investments to address asset condition, and some System Service investments to enable the system to accommodate load growth. For these projects, Hydro One focuses on adherence to the total project cost rather than adherence to in-year expenditures. Table 3 provides the overall project expenditure forecasts, the in-year expenditures and in-service additions planned for 2026, the in-year expenditures and in-service additions planned for 2027, and the accompanying variance categories.

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Table 3 - 2026-2027 Distribution Project Summary

			2026 Dx Capital Expenditures ($M)		2026 Dx In-Service Additions ($M)		2027 Dx Capital Expenditures ($M)		2027 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[4]**	**EB-2021-0110 ISD Number**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Variance**	**Forecast**	**Latest Forecast**	**Variance**	**Variance Category**
Carleton Place Francis DS Padmounts	Planning	D-SR-04	3.0	0.0	3.3	0.0	0.0	0.0	0.0	0.0	3.3	3.3	0.0	2026	2030	4	Reprioritization
Ernestown RS Pole Replacement	Planning	D-SR-04	0.3	0.0	0.0	0.0	3.2	0.0	3.5	0.0	3.5	3.5	0.0	2027	2032+	n/a	Reprioritization
Uxbridge DS #2 Upgrade	Planning	D-SR-04	3.1	2.0	3.6	0.0	0.0	1.5	0.0	0.0	3.6	4.5	0.9	2026	2028	2	Reprioritization
Clarke TS M2 Line Relocate	Planning	D-SR-10	0.0	5.0	0.0	0.0	0.0	5.0	0.0	5.0	0.0	10.0	10.0	n/a	2027	n/a	Emergent Needs
Dobbin TS M5 Reconstruction-Howden Quarter Line	Planning	D-SR-10	3.3	0.0	3.5	0.0	0.0	0.0	0.0	0.0	3.5	3.5	0.0	2026	2032+	n/a	Reprioritization
Enfield TS M4 44KV Line Relocation	Execution	D-SR-10	0.0	16.0	0.0	19.9	0.0	0.0	0.0	0.0	0.0	28.0	28.0	n/a	2026	n/a	Emergent Needs
Ingersoll M44/M46 Rebuild	Planning	D-SR-10	0.0	0.0	0.0	0.0	3.1	0.0	3.5	0.0	3.5	3.5	0.0	2027	2031	4	Reprioritization
Kent TS M24 Line Relocation	Execution	D-SR-10	0.0	12.8	0.0	13.3	0.0	0.0	0.0	0.0	0.0	13.3	13.3	n/a	2026	n/a	Emergent Needs
Muskoka TS M1 Relocate-Hwy 169-Bala	Planning	D-SR-10	3.9	0.0	4.8	0.0	0.0	0.0	0.0	0.0	4.8	6.2	1.4	2026	2031	5	Reprioritization
AMI 2.0	Execution	D-SR-12	158.9	183.0	158.9	184.0	161.8	186.5	161.8	168.6	705.6	799.4	93.8	2029	2029	0	Work Definition
Acton Corners DS Upgrade	Execution	D-SS-01	0.0	7.0	0.0	8.6	0.0	0.0	0.0	0.0	2.0	8.6	6.6	2025	2026	1	Work Definition
Armitage TS 44kV Expansion to Stouffville	Planning	D-SS-01	2.0	3.0	2.5	0.0	0.0	3.0	0.0	6.0	2.5	6.0	3.5	2026	2027	1	Execution Factors
Belle River Load Growth	Execution	D-SS-01	2.7	2.0	6.1	0.0	0.0	4.6	0.0	6.6	6.1	8.6	2.5	2026	2027	1	Execution Factors
Belleville TS DESN2 New Feeders	Planning	D-SS-01	0.1	3.5	3.1	0.0	0.0	2.0	0.0	5.5	3.1	9.0	5.9	2026	2026	0	Execution Factors
Belleville TS New DESN - DX to TX Contribution	Planning	D-SS-01	1.7	18.7	1.9	18.7	0.0	0.0	0.0	0.0	1.9	18.7	16.8	2026	2026	0	Execution Factors
Brighton Division DS Load Growth	Planning	D-SS-01	0.0	2.5	0.0	0.0	0.0	2.0	0.0	4.5	0.9	5.1	4.3	2024	2027	3	Reprioritization
Brown Hill TS M5 Extension	Planning	D-SS-01	0.0	5.5	0.0	0.0	0.0	2.2	0.0	7.7	2.5	13.2	10.7	2024	2026	2	Execution Factors
Caledonia TS M3 Conversion	Planning	D-SS-01	2.9	0.0	3.3	0.0	0.0	0.0	0.0	0.0	3.2	3.2	0	2026	2032+	n/a	Reprioritization
Caledonia TS New Feeders	Execution	D-SS-01	0.0	5.2	0.0	0.0	0.0	2.1	0.0	7.0	6.7	8.6	1.9	2024	2027	3	Execution Factors
Commanda DS – Station Refurbishment	Execution	D-SS-01	0.0	0.9	0.0	0.0	0.0	3.1	0.0	4.0	1.1	4.0	2.9	2024	2029	5	Work Definition
Crampton DS + Ostrander DS F3 Load Relief	Execution	D-SS-01	0.0	2.7	0.0	0.0	0.0	2.7	0.0	5.5	0.0	5.5	5.5	n/a	2027	n/a	Emergent Needs
Delaware DS Load Relief	Execution	D-SS-01	0.0	0.0	0.0	0.0	0.0	1.0	0.0	4.5	0.0	4.5	4.5	n/a	2027	n/a	Emergent Needs
Dundas TS M1 Line Build	Execution	D-SS-01	0.0	2.9	0.0	3.3	0.0	0.0	0.0	2.9	0.0	6.2	6.2	n/a	2026	n/a	Emergent Needs
Forest Jura DS Fan Monitoring	Execution	D-SS-01	0.0	2.8	0.0	3.3	0.0	0.0	0.0	0.0	1.5	3.3	1.8	2024	2026	2	Reprioritization
Glen Becker DS Transformer Upgrade	Planning	D-SS-01	0.0	0.0	0.0	0.0	0.0	4.1	0.0	5.5	0.0	9.0	9.0	n/a	2029	n/a	Emergent Needs
Humber Station Load Growth	Planning	D-SS-01	0.0	0.0	0.0	0.0	0.0	4.5	0.0	4.5	0.0	5.0	5.0	n/a	2027	n/a	Emergent Needs

[4] Phases: Planning, Execution, Complete, Cancelled, or Deferred.

Witness: Paul Ankrett; Peter Faltaous; Spencer Gill

			2026 Dx Capital Expenditures ($M)		2026 Dx In-Service Additions ($M)		2027 Dx Capital Expenditures ($M)		2027 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[4]**	**EB-2021-0110 ISD Number**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Variance**	**Forecast**	**Latest Forecast**	**Variance**	**Variance Category**
Ingersoll TS New Feeder Build	Execution	D-SS-01	0.4	5.2	0.0	5.8	0.0	1.5	0.0	5.3	2.9	11.1	8.2	2025	2027	2	Execution Factors
Kemptville West DS Upgrade	Execution	D-SS-01	0.0	5.4	0.0	9.9	0.0	0.0	0.0	0.0	1.1	9.9	8.8	2027	2026	-1	Work Definition
Kirkland Lake Voltage Conversion - Stage 3	Execution	D-SS-01	0.0	7.0	0.0	7.3	0.0	0.0	0.0	0.0	3.3	7.3	4.0	2024	2027	3	Reprioritization
Leamington Area DESN5 Feeder Development	Planning	D-SS-01	25.1	1.0	0.0	0.0	12.8	0.0	51.2	0.0	51.2	32.2	-19.0	2027	2032	5	Reprioritization
Limoges DS F2 Load Relief	Execution	D-SS-01	0.0	3.5	0.0	5.0	0.0	0.0	0.0	3.5	2.3	8.5	6.2	2025	2026	1	Execution Factors
Long Sault North DS Upgrade	Planning	D-SS-01	0.0	0.0	0.0	0.0	0.0	3.9	0.0	6.4	0.0	6.4	6.4	n/a	2027	n/a	Emergent Needs
Macville - new 27.6kV station and feeders	Planning	D-SS-01	0.0	2.3	0.0	0.0	4.4	8.5	4.4	0.0	4.4	10.8	6.4	2027	2028	1	Work Definition
Manning Road and Hwy 2 Load Growth	Execution	D-SS-01	2.3	11.4	5.2	12.3	0.0	3.1	0.0	12.3	5.2	24.6	19.4	2026	2027	1	Execution Factors
Margach DS Load Growth	Planning	D-SS-01	0.0	0.5	0.0	0.0	0.0	7.0	0.0	7.5	0.8	7.5	6.7	2025	2027	2	Reprioritization
Marionville DS T2 Installation	Planning	D-SS-01	0.0	2.5	0.0	0.0	0.0	7.0	0.0	9.5	0.0	10.8	10.8	n/a	2027	n/a	Emergent Needs
Marysville DS Transformer Upgrade	Execution	D-SS-01	0.0	3.1	0.0	5.0	0.0	0.0	0.0	0.0	0.9	5.0	4.1	2026	2026	0	Work Definition
Napanee DS 2 Transformer Upgrade	Planning	D-SS-01	0.0	0.0	0.0	0.0	0.0	2.8	0.0	5.5	1.5	5.6	4.1	2024	2027	3	Work Definition
Nebo TS M5 Load Relief	Execution	D-SS-01	0.0	4.8	0.0	0.0	0.0	2.1	0.0	6.8	0.0	11.6	11.6	n/a	2027	n/a	Emergent Needs
Nebo TS M6 Reconductoring Load Growth	Execution	D-SS-01	0.0	3.5	0.0	4.0	0.0	0.0	0.0	0.0	0.0	4.1	4.1	n/a	2027	n/a	Emergent Needs
New McCowan DS and feeders	Execution	D-SS-01	0.0	3.5	0.0	0.0	0.0	6.2	0.0	9.7	0.0	13.2	13.2	n/a	2027	n/a	Emergent Needs
Orangeville TS M1 Tie Hillsburgh x Erin	Planning	D-SS-01	4.5	0.0	5.4	0.0	0.0	0.0	0.0	0.0	5.4	5.4	0.0	2026	2032+	n/a	Reprioritization
Pelham Centre DS F2 Conversion	Execution	D-SS-01	0.0	3.2	0.0	3.5	0.0	0.0	0.0	3.2	0.4	6.7	6.3	2025	2027	2	Execution Factors
Picton DS Transformer Upgrade	Planning	D-SS-01	0.0	0.0	0.0	0.0	0.0	3.3	0.0	5.6	1.6	5.6	4.0	2024	2027	3	Work Definition
Saugeen Shores DS and Port Elgin Load Growth	Execution	D-SS-01	0.0	6.2	0.0	0.0	0.0	1.7	0.0	7.8	5.4	14.0	8.6	2024	2027	3	Work Definition
Scotland DS Load Relief	Execution	D-SS-01	0.0	1.6	0.0	0.0	0.0	1.6	0.0	3.2	0.0	3.2	3.2	n/a	2027	n/a	Emergent Needs
Shedden DS Refurbishment	Planning	D-SS-01	0.0	1.5	0.0	0.0	0.0	5.0	0.0	6.5	0.0	6.5	6.5	n/a	2027	n/a	Emergent Needs
South Sandwich Load Relief	Execution	D-SS-01	0.1	8.3	0.0	0.0	1.0	8.3	0.0	16.5	2.1	24.8	22.7	2028	2028	0	Execution Factors
Strathroy DS Load Growth	Planning	D-SS-01	0.0	0.5	0.0	0.0	0.0	3.5	0.0	4.0	0.0	4.0	4.0	n/a	2027	n/a	Emergent Needs
Theford DS Load Growth	Planning	D-SS-01	0.0	0.5	0.0	0.0	0.0	4.7	0.0	5.2	0.0	5.2	5.2	n/a	2027	n/a	Emergent Needs
Torbram Load Growth	Execution	D-SS-01	0.0	0.0	0.0	0.0	0.0	10.8	0.0	10.8	0.0	35.2	35.2	n/a	2027	n/a	Emergent Needs
Trenton DS Transformer Replacement	Planning	D-SS-01	0.0	2.0	0.0	0.0	0.0	1.5	0.0	3.5	0.6	3.8	3.2	2023	2030	7	Reprioritization
Wheatley DS_2 Load Growth	Execution	D-SS-01	0.0	0.5	0.0	0.0	0.0	4.1	0.0	4.6	0.0	4.6	4.6	n/a	2027	n/a	Emergent Needs
Whitedog DS Relocation - Load Growth	Execution	D-SS-01	0.0	8.0	0.0	0.0	0.0	6.0	0.0	14.0	0.6	22.0	21.4	2024	2027	3	Reprioritization

			2026 Dx Capital Expenditures ($M)		2026 Dx In-Service Additions ($M)		2027 Dx Capital Expenditures ($M)		2027 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[4]**	**EB-2021-0110 ISD Number**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Forecast**	**Latest Forecast**	**Variance**	**Forecast**	**Latest Forecast**	**Variance**	**Variance Category**
Edgeware/Wonderland/Duart/Longwood Feeder Tie	Planning	D-SS-02	5.5	0.0	6.2	0.0	0.0	0.0	0.0	0.0	6.2	6.2	0.0	2026	2032+	n/a	Reprioritization
Orillia TS M7-Midhurst TS M4 New Tie	Planning	D-SS-02	5.0	0.0	5.1	0.0	0.0	0.0	0.0	0.0	5.1	7.2	2.1	2026	2031	5	Reprioritization
Lac La Croix BESS	Execution	D-SS-04	0.0	10.6	0.0	17.3	0.0	2.3	0.0	2.3	0.0	19.5	19.5	n/a	2026	n/a	Emergent Needs
Lanark DS F2 NEV	Execution	D-SS-06	0.0	4.4	0.0	0.0	0.0	3.5	0.0	4.8	0.0	9.2	9.2	n/a	2028	n/a	Emergent Needs

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SECTION 3.10 – DSP – CAPITAL WORK EXECUTION STRATEGY

3.10.1 INTRODUCTION

This Exhibit describes how Hydro One plans and executes its Distribution capital portfolio. Capital projects and programs move from initiation through planning, design, execution, and closeout. The methods, accountabilities, and controls used to manage work through the capital execution workflow to execute work safely and efficiently are described here.

This Exhibit also describes the project manager and oversight functions used to support execution of the capital portfolio. It outlines the key factors that influence work delivery, including resource availability, material sourcing, fleet requirements, outage scheduling, site conditions and safety considerations. Finally, it describes the initiatives implemented to strengthen execution capability and support the delivery of an increasingly large and complex portfolio of work.

3.10.2 CAPITAL WORK EXECUTION STRATEGY

The Distribution capital portfolio consists of Demand work, Planned work and Emergency response. Each type of work has different drivers, timelines and execution requirements. As a result, Hydro One tailors its planning, scheduling, and execution approach to the work being performed.

3.10.2.1 DEMAND WORK

Demand work is initiated by customers and is delivered through programs and projects. Customer requests can vary in volume, timing, and complexity. This requires flexibility in planning, scheduling, and resource allocation to meet customer needs and service obligations.

Demand programs are generally higher-volume, short-cycle, and repeatable in nature, allowing the work to be completed through a simplified execution strategy. By leveraging the repeatable nature of this work, Distribution can improve efficiency through consistent planning and scheduling. This approach enables higher throughput, improved workflow, and more effective utilization of resource capacity. Examples of Demand programs include

Lies Along New Connection and Service Upgrade requests that are directly adjacent to the existing distribution system and do not require expansion of the primary distribution network.

Demand projects consist of a smaller number of longer cycle projects with higher complexity. This work requires up-front scoping, structured planning, and project management. Project Managers within Distribution coordinate cross-functional execution, oversee scope, cost performance, and proactively manage risks and dependencies. Examples of Demand projects include New Connections and Service Upgrades that require a System Impact Assessment or expansion to the primary distribution system, and Line Relocations.

The execution approach is scaled to the complexity, duration, and risks associated with the work. Demand programs benefit from streamlined planning and scheduling activities that support a high volume of customer requests. Demand projects require additional coordination and project oversight to manage scope, schedule, cost, risks, and dependencies. Figure 1 outlines the Demand work execution lifecycle.

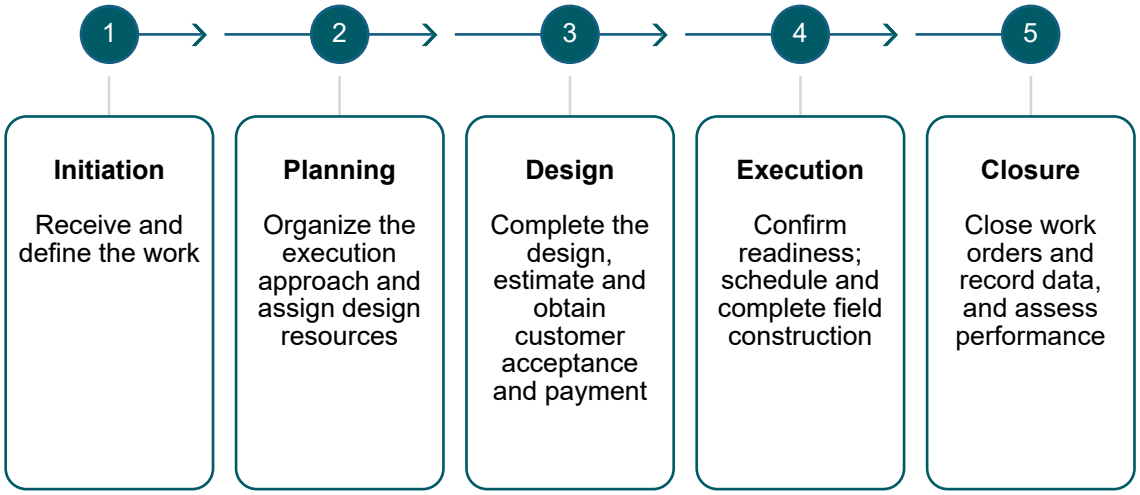


Figure 1: Demand Work Execution Lifecycle

3.10.2.2 DEMAND WORK EXECUTION STRATEGY

INITIATION

The Initiation phase begins when Hydro One receives a customer request from the Contact Centre or through a local office. The work is prioritized, customer requirements are assessed and the appropriate execution approach is used based on the scope, size, and complexity of the work. Requests that exceed established thresholds or require additional delivery rigor are transitioned to the Demand Project execution approach.

Where the customer request is larger or more complex, a Project Manager is assigned to support project delivery, coordinate across stakeholders, and proactively manage project risks. The Project Manager conducts a kick-off meeting with key stakeholders to review the customer requirements, discuss resource needs, identify System Impact Assessment requirements, establish key design and construction milestones, and identify project-specific requirements such as permits, easements, stakeholder engagement, including Indigenous Relations, and other project risks and dependencies. Once the customer requirements and delivery approach are confirmed, the work proceeds to the planning phase.

PLANNING

The Planning phase focuses on confirming customer requirements, assigning resources, and preparing the work for design. The customer request is reviewed, and site-specific requirements are determined before being scheduled to an execution resource.

For larger and more complex work, a preliminary estimate is developed to provide the customer with a cost range and support the customer’s decision on whether to proceed with detailed design and construction.

Throughout the Planning phase, the Project Manager maintains stakeholder alignment, monitors progress against established milestones, and identifies and addresses project risks, assumptions, and dependencies.

DESIGN

In the Design phase, the design and estimate are developed. Design standards are referenced to ensure consistency and an on-site survey is used to determine site specific conditions. The resulting design and estimate are provided to the customer through a Customer Service Contract. Following the customer's acceptance, the work proceeds to the Execution phase.

For larger and more complex projects additional requirements may be needed including securing permits and easements and identifying long-lead materials. A Project Manager is assigned and holds meetings to monitor progress, maintain stakeholder alignment, and address project risks and dependencies

EXECUTION

In the Execution phase, the work plan is developed to support construction. The plan includes resource requirements, material, fleet, and coordination with third parties.

Work is scheduled based on available capacity. Where possible, work is bundled to reduce crew mobilization and travel time. For larger and more complex projects, a Project Manager is assigned to assist execution teams by monitoring progress and addressing issues that may affect delivery.

CLOSURE

In the Closure phase, work records are finalized and information is recorded to support future planning and performance monitoring. For larger and more complex projects, the Project Manager reviews performance against scope, schedule, and cost objectives. Lessons learned and identified opportunities for improvement are used to inform future project delivery.

3.10.2.3 PLANNED WORK

Planned work is initiated by Hydro One to address identified system needs and includes both programs and projects. It is proactively planned, prioritized, and scheduled to support

objectives such as asset renewal, reliability improvements, system capability, and future load growth.

Planned work is initiated by Hydro One and is categorized into programs and projects. Planned program work involves a defined and repeatable scope, including established unit volumes, allocated budgets, and annualized timelines for execution. It also uses the same internal resources as Demand work. This structure enables efficient delivery while allowing flexibility within the year to accommodate seasonality and operational constraints; and higher or lower volumes of Demand work. Examples of Planned program work include Pole Replacement and Component Replacement (e.g., cross arms).

Planned projects range in size and scope from smaller projects released by Asset Management and completed within the year, to larger system capability and load growth projects that can span multiple years. These projects require more detailed planning and unique execution approaches depending on system needs and complexity. Examples of Planned projects include the Barrie TS Construct New Feeders project required to accommodate future load growth in the Barrie area, and the Lindsay M7 Line Upgrade required to improve reliability and load transfer capacity. Figure 2 outlines the Pemand work execution lifecycle.

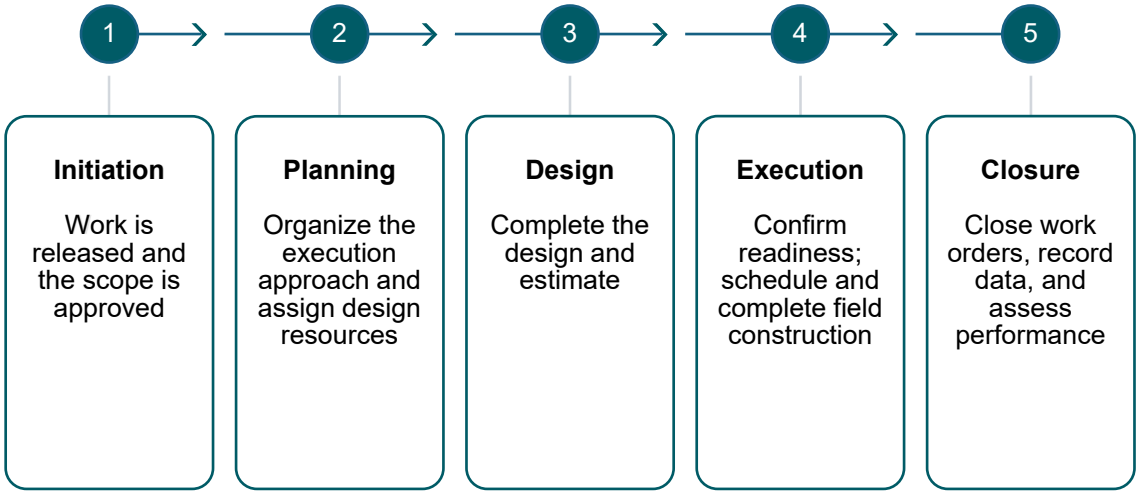


Figure 2: Planned Work Execution Lifecycle

3.10.2.4 PLANNED WORK EXECUTION STRATEGY

INITIATION

The Initiation phase begins with the release of a defined scope of work. During scope development, execution teams are engaged to provide operational input and identify potential execution risks, constraints, and resource requirements.

For larger and more complex work, a Project Manager conducts a kick-off meeting with key stakeholders to review the approved scope, confirm resource requirements, establish key design and construction milestones, and identify project-specific requirements such as permits, easements, long-lead materials, stakeholder engagement, and other execution dependencies. Once the scope is finalized the work proceeds to the Planning phase.

PLANNING

The Planning phase focuses on organizing the approved scope of work into executable design and construction packages and assigning the resources required to deliver the work.

For Planned Programs, the Program Manager accepts the approved scope and releases it to the FBC for planning. The FBC uses Geographic Information System (GIS) mapping to develop a spatial view of the portfolio. This enables work to be bundled into packages that optimize outages to minimize customer impact. Proposed work packages are reviewed with design and construction resources to incorporate operational input and support effective scheduling and execution.

For larger and more complex Planned Projects, the Project Manager is responsible for maintaining the project plan, coordinating stakeholders, and supporting alignment across the project team. Regular project status meetings are held to monitor progress against established milestones and identify risks, assumptions, dependencies, and other execution considerations that may affect project delivery.

DESIGN

The Design phase focuses on developing the detailed designs and estimates.

For larger and more complex Planned Projects, the Project Manager assists with coordinating larger design activities such as obtaining road authority approvals, supporting customer engagement, and coordinating forestry work. Upon completion of the detailed design, the Project Manager consolidates project costs and submits the final estimate to Asset Management for review and approval.

EXECUTION

The Execution phase focuses on completing pre-construction activities, confirming execution readiness, scheduling the work to crews and delivering the approved scope of work. Throughout execution, regular planning meetings are conducted to review program status, resource availability, schedule performance, and execution risks. The level of coordination, oversight, and project controls increases with the complexity, duration, and execution risk of the work.

CLOSURE

The Closure phase occurs as work is completed in the field and focuses on finalizing work records and assessing overall performance. The FBC closes work orders and records completion information, which is used by Program Managers to monitor program performance and support future planning activities.

For larger and more complex projects, the Project Manager reviews project performance, including what worked well and opportunities for improvement. The results of these reviews are used to support continuous improvement and inform future project delivery.

3.10.2.5 EMERGENCY RESPONSE

Emergency Response work is non-discretionary, unpredictable, and driven by factors outside Hydro One's control, including equipment failures and severe weather events. A flexible and responsive approach is required to ensure public safety, system reliability, and timely restoration of service.

Storm response is executed using a phased Incident Management methodology through Local Area Command Centres (LACCs) and Regional Area Command Centres (RACCs). This work is time-critical, and high-impact. The methodology emphasizes early assessment, structured command and control, coordinated execution, and disciplined communication. The level of command and coordination applied is proportionate to the scale, duration, and complexity of the storm event. LACCs focus on tactical, local execution of restoration work, while RACCs provide regional oversight and resource coordination to support efficient and safe restoration. Emergency response activities are executed through five phases: Readiness and Activation, Assessment, Prioritization and Execution, Stabilization, and Deactivation. Figure 3 outlines the Emergency Response work execution lifecycle.

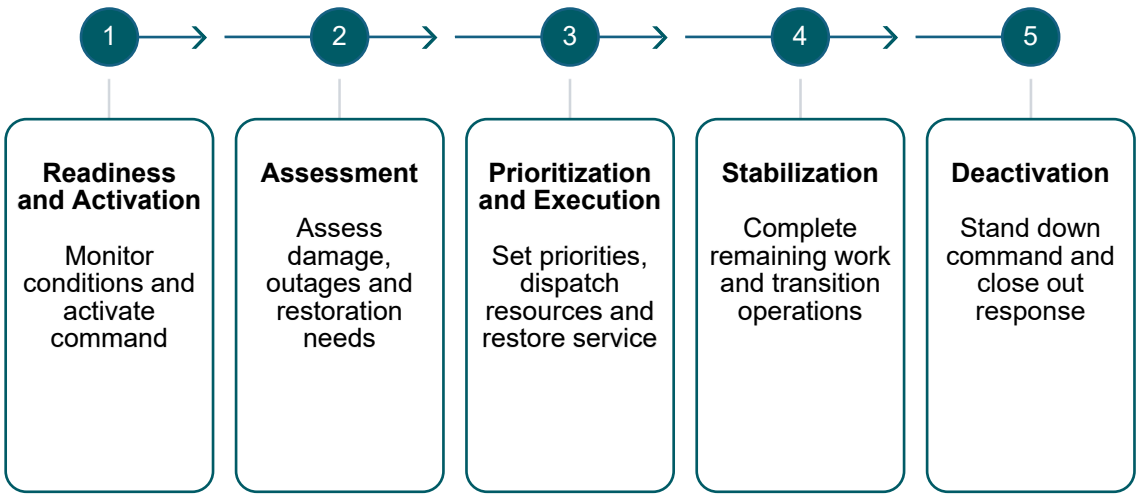


Figure 3: Emergency Response Lifecycle

READINESS AND ACTIVATION

During this phase, weather forecasts, system conditions, and resource availability are assessed to determine the potential impact of a storm event. A LACC is activated when storm conditions exceed the capacity of normal operations and require dedicated local

command and dispatch whereas a RACC is activated when storm impacts extend beyond a single LACC and require regional coordination and prioritization. Command structures are established, roles and responsibilities are assigned, and storm response tools and systems are activated. The level of readiness and activation applied is proportionate to the severity, geographic scope, and operational risk of the event, ensuring timely escalation and effective coordination of restoration activities.

ASSESSMENT

During this phase, storm impacts are evaluated for system damage, outage conditions, and restoration needs. Damage Assessors (design and construction) are dispatched at the local level through the LACC to complete feeder-based damage assessments and confirm field conditions. Assessment information is validated and reflected on digital whiteboards to build local situational awareness. At the regional level, the RACC consolidates assessment of information across active LACCs to establish a regional operating picture. Outputs from the Assessment phase inform restoration priorities, Estimated Times of Restoration (ETRs), resource requirements, and escalation decisions, with the depth and pace of assessment activities scaled to the size, complexity, and risk of the event.

PRIORTIZATION AND EXECUTION

During this phase, restoration work is actively planned, sequenced, and delivered. The LACC prioritizes outages based on public safety, customer impact, and system conditions, and dispatches Lines, Forestry, and supporting resources to execute restoration work. ETRs are established and updated based on assessment findings and field progress. In parallel, the RACC provides regional oversight by resolving competing priorities across LACCs, coordinating resource movement and mutual assistance from contractors, and addressing logistical or operational barriers that cannot be resolved locally. Planning and execution occur iteratively during this phase, allowing restoration activities to adapt to evolving conditions while maintaining safety, efficiency, and customer transparency as top priorities.

STABILIZATION

The Stabilization phase ensures restoration is completed safely and efficiently while enabling an orderly transition out of storm response mode. During this phase, storm impacts have been substantially addressed, and restoration activities shift from emergency response to controlled completion. The volume of outages and incidents declines, system conditions stabilize, and remaining work becomes localized and manageable through normal operational processes. The LACC focuses on completing residual restoration activities, validating ETRs, and preparing to transition control back to normal operations, while the RACC confirms regional stability, demobilizes additional and mutual-aid contractors, and prepares for deactivation.

DEACTIVATION

Deactivation ensures a controlled and accountable transition from storm response to steady-state operations and sets the conditions for post-storm review and continuous improvement.

During this phase, the emergency command structures are stood down. The RACC Commander confirms regional stability and deactivates the RACC, while the LACC is surrendered back to the Integrated System Operating Centre. Resources and mutual assistance contractors are demobilized, command roles are closed out, and final documentation, cost tracking, and system updates are completed.

3.10.3 EXECUTION OVERSIGHT, GOVERNANCE AND COORDINATION

Hydro One's execution strategy includes oversight, governance, and coordination activities that support the safe, efficient, and cost-effective delivery of the Distribution capital portfolio. As the scale and complexity of the capital program continues to grow, these activities provide visibility into portfolio performance, emerging risks, resource requirements, and changing operational conditions. Together, they support informed decision-making, effective risk management, and alignment between execution activities and business objectives.

Project and Program Managers provide day-to-day oversight and coordination across the capital portfolio. Project Managers support the delivery of individual investments by managing scope, schedule, cost, stakeholder coordination, and execution risks. Program Managers provide portfolio-level oversight, monitor overall performance, and identify emerging risks and opportunities.

Field Business Centres coordinate planning, scheduling, and resource deployment across the province. In coordination with Project and Program Managers, FBCs translate capital plans into executable work, identify capacity constraints, and support adjustments to schedules and resource allocation as conditions change.

Standardized reporting and regular portfolio reviews provide consistent visibility into project, program, and portfolio performance. Distribution leadership reviews execution performance, risks, opportunities, resource capacity, workload requirements, and execution priorities to support informed decision-making and timely responses to changing customer, operational, and system needs. These reviews enable Hydro One to proactively address capacity constraints, rebalance workloads, reprioritize work, and leverage external resources, where appropriate.

Together, these oversight, governance, and coordination activities provide the visibility, accountability, and decision-making framework required to support the successful execution of Hydro One's growing capital investment portfolio. The framework supports efficient resource utilization, proactive management of execution risks, organizational agility, and the safe, reliable, and cost-effective delivery of capital investments.

3.10.4 FACTORS IMPACTING WORK EXECUTION

EXECUTION RESOURCES AND APPROACH

Distribution Lines and Design Services is responsible for the design and construction activities required to deliver the Distribution capital program. Its regular full-time workforce, comprising PWU, Society, and Management employees, is supplemented by direct-hire casual hiring hall resources and contractors as required.

To manage higher workloads in 2028 to 2032, Hydro One will use various resource strategies to expand capacity and maintain flexibility. This includes developing skilled resources through the Lines Apprentice Program, supplementing internal crews with direct-hire casual hiring hall resources, deploying overtime on a targeted basis and the use of qualified contractors. This flexible workforce strategy allows Hydro One to adjust its resource mix as work volumes, execution priorities, and operational needs evolve, while maintaining appropriate oversight, safety, and work quality. Additional details regarding Distribution's workforce plan are provided in Exhibit E-06-02, Workforce Planning.

Development of internal capabilities: Hydro One's Lines Apprentice Program develops skilled and certified Powerline Technicians. The program combines formal technical training, on-the-job learning, and mentorship and supports workforce sustainability, succession planning, and the development of future skilled resources. Apprentice hiring is managed to ensure appropriate supervision and maintain safety and work quality.

Overtime: Overtime is used as a targeted execution tool to support Demand work, emergency response activities, and planned capital investments. It provides additional flexibility to respond to customer requirements, restore service following emergency events, and complete Planned work efficiently through extended workdays or compressed schedules where appropriate.

Use of contractors: Contractors will provide Hydro One with the scalability and flexibility it needs to support an expanded capital program. Hydro One maintains a pool of pre-qualified service providers and uses competitive procurement processes to secure resources. Contractor-delivered work is subject to the same oversight, governance, tracking, and reporting requirements as internally delivered work. Contractors are primarily utilized for larger Demand and Planned projects. This provides additional execution capacity while allowing internal resources to focus on work that benefits from local knowledge, operational familiarity, customer responsiveness, and integration with ongoing system operations.

WORK PROGRAM DELIVERY FACTORS

Hydro One manages material sourcing, equipment and fleet availability, outage coordination, site conditions, and safety to reduce execution risk and support predictable delivery outcomes. Together, these activities enable Hydro One to optimize resource utilization, maintain operational flexibility, and support the safe, timely, and cost-effective execution of capital work.

Material Sourcing and Availability: Effective supply chain management plays an important role in supporting capital portfolio execution. Materials and equipment must be available on time to support efficient work execution, reduce schedule risk, and minimize delays. Hydro One manages material supply risks through strategic sourcing, supplier diversification, long-lead procurement planning, and supplier performance management. Hydro One secures supplier contracts, procures highly engineered and long-lead materials in advance where appropriate, and works with alternative suppliers to improve supply resilience. Additional information regarding procurement practices is provided in Exhibit E-05-01.

Hydro One's central warehouse supports execution by coordinating material delivery across the province, improving logistics efficiency, supporting project-specific material kitting, and reducing field productivity losses associated with material availability and transportation. This ensures construction resources have the right materials at the right time.

Equipment and Fleet Accessibility: Access to specialized equipment and fleet is an important component of Hydro One's execution strategy. Capital work often requires unique equipment based on design requirements, site conditions, seasonal factors, and accessibility considerations. Effective fleet planning helps ensure the resources required to execute capital work are available when needed while supporting safe and efficient field operations.

Fleet capacity must align with a larger future capital program, and early planning and scheduling help optimize equipment use across multiple work programs. For example,

coordinating use of specialized assets like Mobile Unit Substations ("MUS") helps keep projects on schedule. Additional information regarding fleet planning and management is provided in Exhibit B-04-01, Section 4.2.

Outage Scheduling: Many projects and programs require planned outages to safely complete construction activities. As the distribution system becomes increasingly complex, including the continued growth of Distributed Energy Resources, effective outage coordination promotes execution efficiency and minimizes customer impacts. Hydro One aligns multiple work activities within a single outage window to increase productivity and resource utilization, reduce customer disruption, and minimize the risk of delays associated with outage cancellations or rescheduling. For example, Hydro One coordinates asset renewal and defect correction work with smart switch installations and leverages existing station outages to complete Distribution Lines work where appropriate. Additional information regarding outage management is provided in Exhibit E-04-05.

Site Conditions: Hydro One's service territory spans diverse geographic regions and operating environments, creating a range of site-specific execution considerations that influence how and when work is performed. Factors such as terrain, accessibility, seasonality, environmental constraints, and regional operating conditions can affect construction methods, equipment requirements, resource deployment, and project schedules. Hydro One incorporates these considerations into execution planning to support safe, efficient, and cost-effective delivery of capital investments. Work is scheduled and coordinated to take advantage of favourable site conditions where possible, including winter access opportunities, seasonal construction windows, and specialized equipment requirements.

Safety: Hydro One integrates safety requirements into capital work planning and delivery to manage execution risk and support work quality and field performance.

Figure 4 shows a slight improvement in the recordable injury rate. The rate increased in 2025, primarily due to low-severity events; approximately 90% of incidents were minor,

most commonly slips, trips and falls. Hydro One's overall safety performance remains strong relative to industry peers.

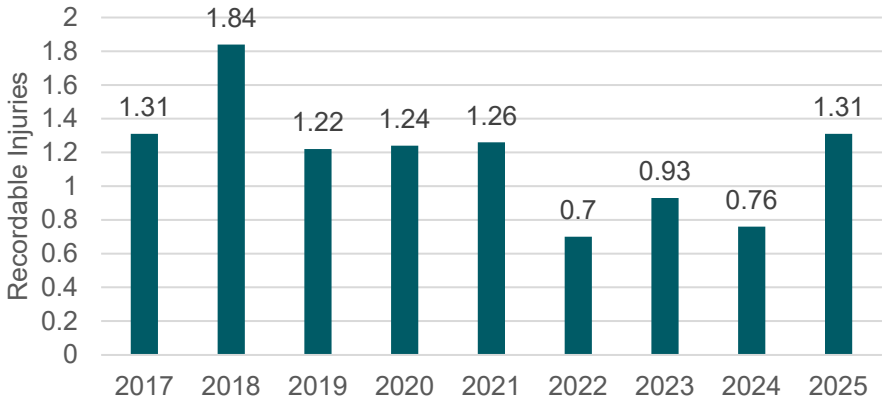


Figure 4: Capital Work Execution, Distribution – Recordable Injury Rate (per 200,000 hours worked)

Hydro One also measures public awareness of electrical safety through six core questions asked of randomly selected Ontario residents. The public safety awareness index was 82% in the 2024 survey.

Hydro One's Health, Safety and Environment function supports health and safety management systems, training, field operations, learning, analytics and reporting. A cross-functional Safety Improvement Team identifies measures to help prevent serious injuries and fatalities.

Hydro One completed the 12 initiatives in its 2020–2024 Safety Improvement Plan. The 2026–2030 Safety Plan includes initiatives under six pillars: employee engagement, programs and procedures, hazard and risk management, incident management, education, and evaluation, with a goal of zero life-threatening or life-altering injuries and fatalities. Employees reported more than 10,000 Near Misses and Safety Catches in 2025, exceeding the annual target of 5,700 and supporting earlier identification and mitigation of hazards. Frontline safety practices include weekly safety bulletins, tailboard sessions and onsite planning meetings to identify hazards and reinforce safe work plans. Safety rollouts

reinforce roles, reporting and job planning. Managers and supervisors completed more than 10,000 Workplace Safety Observations in 2025 to provide field coaching and feedback. The Human Performance program uses root-cause analysis, tools, processes and coaching to reduce human error and improve safety, work quality and reliability.

3.10.5 CONTINUOUS IMPROVEMENT

Hydro One is strengthening its execution capability to deliver a larger and more complex Distribution capital portfolio safely, efficiently, and cost-effectively. Key improvements enhance contractor oversight, storm restoration, project coordination, reporting, and frontline planning and scheduling.

Contract Management: A Contract Management team was established to oversee contracts, coordinate delivery, manage vendor performance and quality, and support pre-qualification and procurement. This enables Hydro One to scale capacity as workloads change while holding contracted work to the same standards, oversight, and acceptance requirements as internally delivered work.

Storm Restoration Improvement: Storm restoration has been improved through Digital Storm Boards, enhanced training and exercises, better forecasting and resource tools, stronger Regional Area Command Centre activation procedures, and improved crew coordination, damage assessment, and restoration planning. These measures improve situational awareness, resource deployment, and decision-making, supporting faster, more efficient restoration while maintaining reliability and customer focus.

Subdivision Project Managers: In response to developer feedback, Hydro One established a dedicated Subdivision Project Management team to coordinate projects from initiation to completion. Project Managers provide a single point of contact, manage scope, cost, schedule, milestones, and stakeholder coordination, and escalate risks and remove delivery barriers. The team has improved communication, transparency, and project delivery, as reflected in positive feedback from subdivision developers.

Reporting and Analytics: Distribution has expanded its reporting and analytics capabilities using Power BI and Tableau dashboards that integrate multiple data sources and improve visibility into project and program performance. These tools support earlier identification of issues and more informed management of the growing capital program.

Frontline Customer Service Improvements: A new phone system has been implemented that provides service metrics, call recording, and customer sentiment analysis; a standards and practice team has been established to support training and onboarding; and new dashboards to improve workload and performance visibility.

Conclusion

Hydro One's execution strategy is designed to deliver a materially larger Distribution capital portfolio in 2028–2032 safely, reliably, and cost-effectively. It tailors planning, oversight, and controls the timing, complexity, risk, and operational requirements of Demand work, Planned work, and emergency response.

Integrated governance, coordinated scheduling, a flexible mix of internal and external resources, and proactive management of materials, fleet, outages, site conditions, and safety provide the capacity and discipline required to execute the plan. Supported by targeted continuous improvements, this framework enables Hydro One to adapt to changing conditions, manage delivery risk, and maintain accountability for customer service, system reliability, and cost performance.

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SECTION 3.11 – DSP – MATERIAL INVESTMENT SUMMARY DOCUMENTS

3.11.1 INTRODUCTION

Distribution System Plan (DSP) Investment Summary Documents (ISD) are attached to this section. ISDs are provided where any proposed capital expenditure within the DSP exceeds a materiality threshold of $1M. ISDs for General Plant investments are provided in GSP Section 4.11.

Hydro One has endeavored to maintain the ISD structure from its previous Distribution Rates Application (EB-2021-0110) and, where applicable, has added new ISDs and retired ISDs that are completed, merged with other ISDs, or are no longer required.

Table 1 below presents material Hydro One Distribution ISDs included in the DSP for the 2028-2032 period.

Table 1 - Material DSP Investments

ISD	Investment Name	Change
System Access		
D-SA-01	Joint Use and Relocations	Existing
D-SA-02	New Load Connections, Upgrades, Cancellations	Existing
D-SA-03	Customer Demand Distributed Energy Resources	Existing
D-SA-04	Metering Sustainment	Existing
D-SA-05	Broadband	New
System Renewal		
D-SR-01	Distribution Stations Demand Capital Program	Existing
D-SR-02	Mobile Unit Substation Program	Existing
D-SR-03	Distribution Station Planned Component Replacement Program	Existing
D-SR-04	Distribution Station Renewal	Existing
D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	Existing
D-SR-06	Distribution Lines PCB Equipment Replacement	Retired as Program Ended

ISD	Investment Name	Change
D-SR-07	Pole Sustainment Program	Existing
D-SR-08	Distribution Lines Minor Component Replacement	Existing
D-SR-09	Submarine Cable Replacement Program	Existing
D-SR-10	Distribution Lines Sustainment Initiatives	Existing
D-SR-11	Lifecycle Optimization & Operational Efficiency Projects	Retired – Merged with D-SR-04
D-SR-12	Advanced Meter Infrastructure 2.0 (AMI 2.0)	Existing
D-SR-13	Distribution Spare Transformer Purchase Program	New
D-SR-14	Selective Undergrounding	New
D-SR-15	Underground Cable Replacement and Rejuvenation Program	New
D-SR-16	Creation of Virtual Assets	New
D-SR-17	Voltage Consolidation	New
System Service		
D-SS-01	System Upgrades Driven by Load Growth	Existing
D-SS-02	Reliability Improvements	Existing
D-SS-03	Demand System Modifications	Existing
D-SS-04	Energy Storage Solutions	Existing
D-SS-05	Distribution Automation & Sectionalization Program[1]	Existing
D-SS-06	Power Quality and Stray Voltage	Existing
D-SS-07	DER Hosting Capacity	New
D-SS-08	System Monitoring	New
D-SS-09	Intelligent Grid Platform	New
D-SS-10	Real Time Distribution Station and Feeder Monitoring Program	New

[1] Previously Worst Performing Feeders

D-SA-01	JOINT USE AND RELOCATIONS
Primary Trigger:	Mandated Obligations
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness, Financial Performance

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	50.7	51.7	52.8	53.8	54.9	263.9
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This investment involves the rearrangement, relocation and/or the replacement of poles as required to accommodate third party attachments or due to siting conflicts with work by Road Authorities, railways and private landowners. 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, 1990* (PSWHA), respectively. The investment is expected to ensure ongoing compliance with these requirements to create mutual benefits for Hydro One and third party proponents to support infrastructure development, generate external revenue, and realize cost sharing opportunities where applicable.

1.0 INVESTMENT NEED

This investment consists of two segments within the program: Joint Use and Relocations. The purpose of these investments is to modify or upgrade distribution system facilities to accommodate the requirements of third party attachers such as telecommunication providers who occupy Hydro One assets, or to relocate facilities at the request of Road Authorities and private landowners.

The main driver of the Joint Use segment is to provide third party attachers with access to Hydro One's support structure network. Revenue generated through joint use attachments is reflected in Exhibit D-02-02, Subsection 2.1.2. Third party attachers' access to Hydro One assets is subject to joint use agreements between the parties and Hydro One and aligns with the provisions in Hydro One's Distribution Licence to provide reasonable access to all Canadian carriers, as defined in the *Telecommunications Act, 1993*. 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. Third party attachers are responsible for all applicable costs related to their request.

The main driver of the Relocation segment 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 Works on Highways Act* (PSWHA) and associated Ministry of Transportation Ontario (MTO) guidelines, and line relocation work requested by customers and third parties in accordance with Hydro One's Conditions of Service and the Distribution System Code. These capital expenditures are required to complete relocation work as requested by the third party. Such requests may be made to support property development or to address requirements of the Road Authority, where adverse impacts to Hydro One plant have been identified. The applicable costs are 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 segments are driven by customer demand and thus must be accommodated within Hydro One's work program.

2.0 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 to accommodate the use of this equipment by third party joint use proponents. These attachers may include telecommunication companies (communication circuits), municipalities (streetlighting), 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.

Over the 2028-2032 period, the total investment of $64.7M in net costs in the Joint Use segment, which follows a similar trend to recent years, as shown in Table 1 below.

Table 1 - Joint Use - Investment Expenditures

($M)	Plan[1] 23-27	Act/Fcst [2] 23-27	2028	2029	2030	2031	2032	Total 28-32
Net Capital Expenditures	86.2	59.9	12.4	12.7	12.9	13.2	13.5	64.7

The Joint Use program does not include any investments related to the execution of 'make-ready' work required to be completed under O. Reg. 410/22 (Electricity Infrastructure – Designated Broadband Projects) as amended in 2025 by O. Reg. 248/25, to accommodate approved Internet Service Provider (ISP) attachments to Hydro One poles (the "Broadband Regulation"). The scope of work for the Joint Use program includes ISP applications that are outside of the provincial Broadband program.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[2] Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

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 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 initiated by road authorities 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 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 2028-2032 period, the total investment of $199.1M in the Relocations segment, which follows a similar trend to recent years, as shown in Table 2 below.

Table 2 - Relocations – Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Net Capital Expenditures	55.3	170.6	38.3	39.0	39.8	40.6	41.4	199.1

3.0 OUTCOMES

3.1 OEB RRF OUTCOMES

Investments made under this investment support the Ontario Energy Board's Renewed Regulatory Framework (RRF) outcomes of Customer Focus, Public Policy Responsiveness and Financial Performance.

Table 3 presents anticipated benefits because of the investment in accordance with the RRF.

Table 3 - Outcome Summary

Customer Focus	• Enable the shared use of Hydro One infrastructure in a manner that delivers value to ratepayers while meeting the needs, interests, and service requirements of third party attachers, Municipal Road Authorities and other stakeholders.
Public Policy Responsiveness	• Maintain compliance with Section 22.1 of Hydro One's Electricity Distribution Licence for access to distribution poles by our third party attachers. • Fulfill legal and regulatory obligations related to asset relocations in accordance with the PSWHA, Hydro One's Conditions of Service and the Distribution System Code.
Financial Performance	• Support the installation of new third party attachments that may generate incremental external revenue, helping to offset the rates revenue requirement. • Deliver prudent cost management through cost-sharing opportunities on distribution system upgrades and renewals initiated by Municipal Road Authorities, third party attachers, or customer requests.

4.0 EXPENDITURE PLAN

The Joint Use and Relocations segments comprise two externally driven, non-discretionary activities. The Joint Use segment facilitates "make-ready" investments required to enable third party attachments (e.g., telecommunications providers, municipalities, and LDCs), including pole class and height upgrades. The Relocations segment addresses line relocations required to accommodate municipal and provincial road projects, customer development, railways, and public lands, with costs recovered in accordance with the PSWHA, Conditions of Service, and applicable regulations.

Tables 4, 5, and 6 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 rate period.

Table 4 - Hydro One - Investment Expenditures[3]

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Investment Cost	291.8	385.2	83.9	85.6	87.3	89.1	90.9	436.8
Less Removals	25.0	29.9	6.9	7.1	7.2	7.3	7.5	36.0
Less Capital Contributions	125.3	125.6	26.3	26.8	27.4	27.9	28.5	136.9
Net Capital Expenditures	**141.5**	**229.7**	**50.7**	**51.7**	**52.8**	**53.8**	**54.9**	**263.9**

Table 5 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Investment Cost	-	0.91	0.01	0.01	0.01	Embedded in Hydro One Networks		
Less Removals		0.13	0.00	0.00	0.00			
Less Capital Contributions		0.37	0.00	0.00	0.00			
Net Capital Expenditures		**0.41**	**0.00**	**0.00**	**0.00**			

Table 6 - Peterborough RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Investment Cost	-	0.84	0.01	0.01	0.01	Embedded in Hydro One Networks		
Less Removals		0.13	0.00	0.00	0.00			
Less Capital Contributions		0.33	0.00	0.00	0.00			
Net Capital Expenditures		**0.38**	**0.00**	**0.00**	**0.00**			

2023-2027 EXPENDITURES

Over the 2023-2027 period, Hydro One forecasts expenditures for this investment to be $88.2M higher than planned. This variance is a result of forecasted negative variance for the Joint Use segment (-$26.3M) offset by a positive variance for the relocations segment (+$115.3M). The primary drivers of the variance are work volumes and cost pressures.

The variance for the Joint Use segment over the 2023 – 2025 period was primarily due to lower application volumes from ISPs due to the introduction of the Broadband Regulation.

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

The variance for the Relocations segment is primarily driven by a higher volume of relocation requests compared to plan from municipal road authorities and the MTO. The primary projects contributing to the variance are relocations because of Metrolinx electrification and expansion initiatives, the Bradford Bypass and Highway 413. Road Improvements with significant project scope concentrated in the Region of Peel as well as MTO relocations in the St. Thomas and Aylmer areas feeding several large manufacturers also contributed to the variance. From 2023-2025, the net investment costs associated with municipal Road Authorities and MTO requests represented the majority of the planned net spend for the segment. In addition, the Relocation segment variance is also driven by the increased work volume and associated costs to perform private relocation work for the Greenstone gold mine.

The 2023-2025 program costs were impacted by material cost escalation. This is consistent with the broader cost increases observed across materials presented in SPF Section 1.8, Table 1. The Relocations segment is particularly exposed to these pressures because project execution often requires specialized utility construction resources, civil construction activities, electrical equipment, poles, conductors, and contractor services. In addition, increased volumes of work drove the need for additional resources and associated increased labour costs. Relocation projects compete for the same labour as large infrastructure projects across Ontario including highway expansions, transit projects, bridge rehabilitation programs, and municipal infrastructure investments.

As a result of the variance drivers experienced from 2023-2025, Hydro One adjusted its forecasted spending under the investment for 2026 and 2027.

2028-2032 EXPENDITURES

Over the 2028-2032 rate period, forecast expenditures are based on historical program expenditures, adjusted for known forecast scope, inflation, and integrated work volumes from acquired utilities. Over the 2028-2032 period, Hydro One plans to invest an average of $52.8M annually, totaling $263.9M, to modify, relocate, reconstruct, and upgrade

distribution poles and line equipment to support third party attachments and/or Road Authority driven relocation requirements.

The 2028-2032 Joint Use segment investment is in line with the 2023-2027 actual and forecast expenditures. Hydro One forecasts that investments under the Relocation segment will exceed historic levels. Municipalities are expected to continue expanding based on average provincial population growth projections of 1.0% annually over the 2028-2032 period[4] and Road Authorities require existing infrastructure to be relocated to provide for these expansions. Also, over the next 10 years, the Ontario government plans to build new hospitals, transit systems and highways by allocating $147 billion to projects such as Metrolinx electrification, construction of the Bradford Bypass, Highway 413, and bridge rehabilitation works across Ontario.[5]

5.0 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 joint use requests, and Hydro One would not be compliant with statutory obligations if it did not service relocation requests by Road Authorities.

6.0 EXECUTION RISK AND MITIGATION

While Hydro One has significant experience executing Joint Use and Relocation work, this program is variable because both demand and costs are largely driven by proponent-initiated requests and site-specific requirements. Actual annual volumes may differ from forecast due to changes in customer demand, development activity, policy direction, and the timing of the proponents' projects. In addition, program costs may vary depending on the scope and complexity of joint use and relocation projects, the amount of work required, material availability, and broader market cost pressures. Hydro One manages this uncertainty through ongoing coordination with proponents, scheduling and prioritization of work to meet requested service dates, monitoring of volumes and program costs, and updates to planning assumptions as new information becomes available.

[4] Ontario population projections | ontario.ca
[5] 2025 Ontario Budget | In Brief

D-SA-02	NEW LOAD CONNECTIONS, UPGRADES, CANCELLATIONS
Primary Trigger:	Customer Requests
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	311.7	327.9	339.7	355.6	368.3	1,703.3
Orillia RZ	1.40	1.47	1.53	Embedded in Hydro One Networks		
Peterborough RZ	1.84	1.94	2.02			

Summary:

This investment enables 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, and will enable residential construction in the province of Ontario.

1.0 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 approximately 94,500 new connections, 39,400 service upgrades and 15,200 service cancellations over the 2028-2032 planning period.

Pursuant to its legal and regulatory obligations under the *Electricity Act, 1998,* the 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 receiving a 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. Forecast new connection work is divided into three major categories: (1) non-subdivision new connections, (2) subdivisions, and (3) non-subdivision large expansions (i.e., 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. Forecast service upgrade work is divided into two major categories: (1) service upgrades, and (2) large expansions (i.e., 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.

Tables 1, 2, and 3 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast volumes for the 2023-2027 rate period and forecast volumes for the 2028-2032 planning period.

Table 1 - New Connection, Service Upgrade and Service Cancellation Volumes - Hydro One

Description	Plan[1] 23-27	Act/Fcst[2] 23-27	2028	2029	2030	2031	2032	Total 28-32
New Connections	85,140	88,580	18,210	18,580	18,640	18,710	18,760	92,900
Service Upgrades	21,660	29,370	6,940	7,390	7,740	8,100	8,470	38,640
Service Cancellations	25,120	14,460	2,900	2,960	2,980	2,990	2,990	14,820

Table 2 - New Connection, Service Upgrade and Service Cancellation Volumes – Orillia RZ

Description	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
New Connections	1,032	680	151	154	156	156	157	774
Service Upgrades	222	166	47	50	53	55	58	263
Service Cancellations	153	103	25	26	26	26	26	129

Table 3 - New Connection, Service Upgrade and Service Cancellation Volumes – Peterborough RZ

Description	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
New Connections	1,851	648	164	167	168	169	170	838
Service Upgrades	414	259	81	86	90	94	99	450
Service Cancellations	203	308	40	40	41	41	41	203

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[2] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Annual breakdowns of the historic and forecast new connection, service upgrade and service cancellation volumes for Hydro One Networks are shown in Figures 1, 2 and 3 below, respectively.

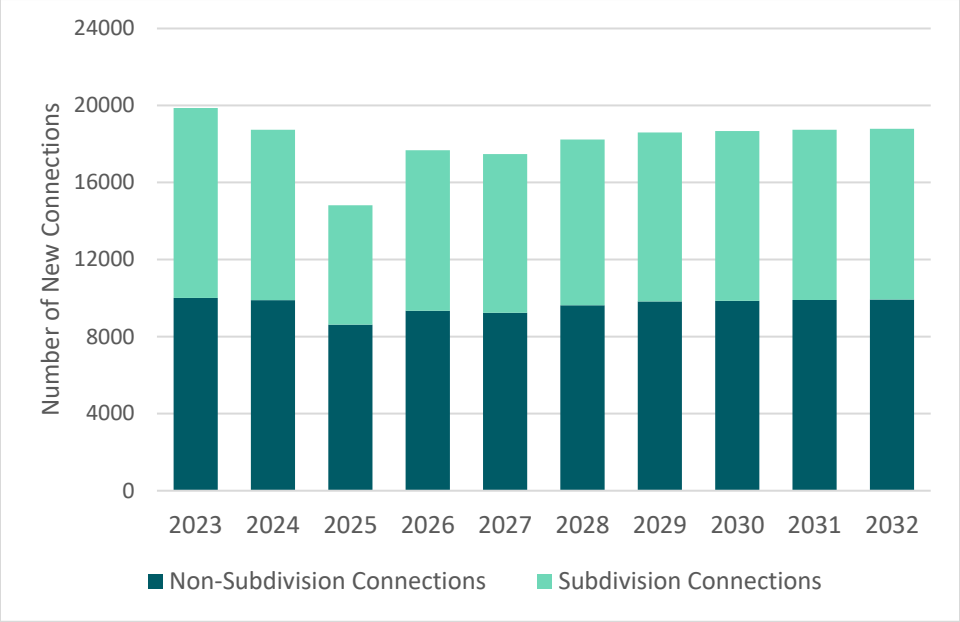


Figure 1: Hydro One New Connection Volumes[3]

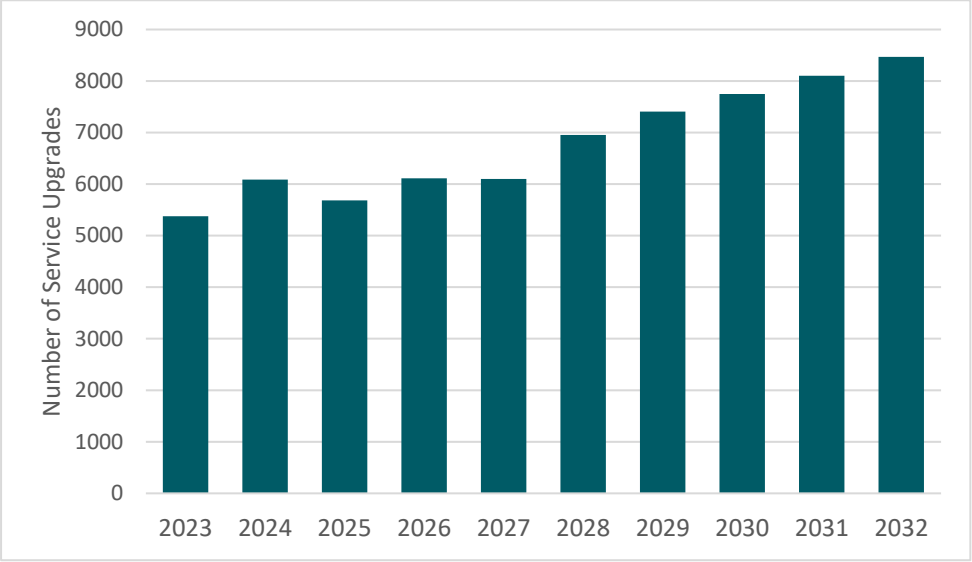


Figure 2: Hydro One Service Upgrade Volumes

[3] 2023-2025 actual volume and 2026-27 forecast volumes.

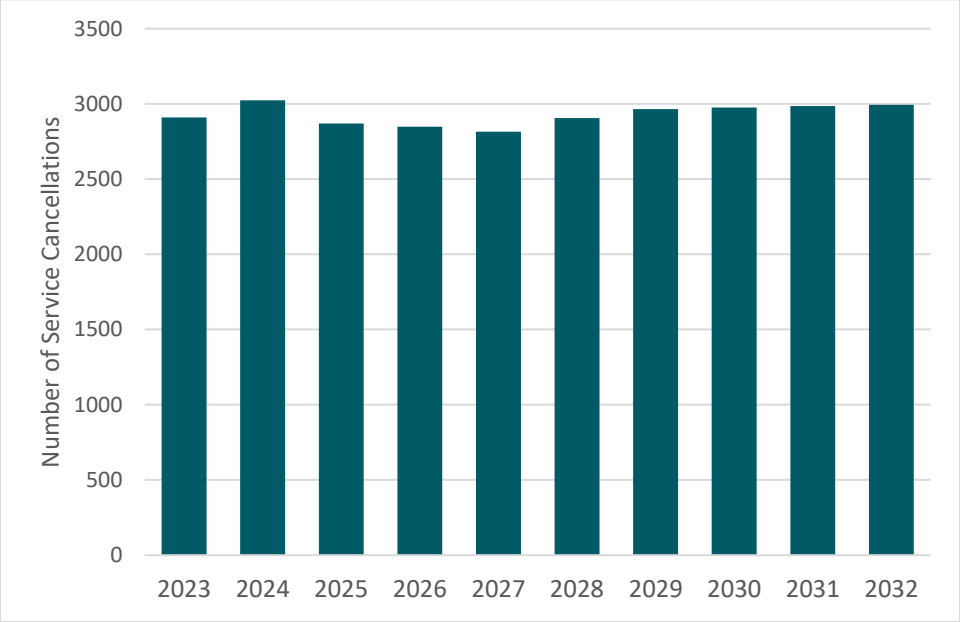


Figure 3: Hydro One Service Cancellation Volumes[4]

Forecasts for new connections, service upgrades, and service cancellations are based on historic volumes, number of customers, and forward-looking information to capture the impact of electrification (e.g., EV chargers and heat pumps) as detailed in Exhibit D-05-01. Population growth, including natural growth and government immigration targets, is a key determinant of customer growth. Immigration levels are expected to normalize following the temporary increase observed between 2022 and 2024, with a view to the government's objectives of reducing housing demand pressures. Accordingly, Hydro One forecasts steady growth in its customer base and a corresponding steady volume of customer connections over the 2028-2032 planning period. The lower-than-normal number of connections in 2025 was primarily due to lower population growth.

As further discussed below, and in Exhibit D-05-01, the adoption of EV chargers and heat pumps is another factor that has been considered in deriving the forecast in this program.

[4] 2023-2025 volumes are actual; 2026-2032 volumes are forecast.

1.1 PLANNING FOR ELECTRIFICATION

The Independent Electricity System Operator's (IESO) 2026 Annual Planning Outlook reference scenario forecasts 65% net energy demand growth to 2050, a scenario that will result in a significant increase in the amount of energy that the distribution system must provide.

Hydro One expects that new types of loads such as at-home EV chargers and heat pumps will increase individual residential customer peak load and the coincident peak load among groups of residential customers. This expectation is based on two key analyses. First, meter data from approximately 700 Hydro One residential customers with at-home Level 2 EV charging were evaluated to determine the impact of EV charging on peak load. Second, a review of cold-climate heat pump technologies was conducted to estimate the additional load from future heat pump and gas hybrid heating systems.

Increased residential load is expected to result in a need to increase the size of the service transformer, secondary bus, or service wire, or increase the number of service transformers, as determined on a case-by-case basis. These changes may be required to manage transformer loading, secondary bus loading, and secondary bus and service wire impedance, to avoid overloaded assets and customer low voltage (power quality) issues.

Hydro One has updated its design practices to reflect increasing residential customer load resulting from at-home EV charging and heat pump systems. Starting in 2028, newly installed assets will be sufficient to allow new connecting customers to employ at-home EV charging and hybrid heat pump systems. Additionally, when connecting a new residential customer or upgrading an existing residential service, existing assets will be assessed to confirm they can accommodate EV charging for the connecting customer.

Hydro One forecasts that these changes will increase the average annual cost of new load connections and service upgrades by approximately $24 million annually over the 2028-2032 planning period. This investment is necessary to ensure that distribution system secondary assets such as service transformers, secondary bus and cable are sufficiently sized to supply increased load associated with residential electric vehicle charging when

a residential connection or service upgrade request is received. This represents a net cost increase of approximately 8% for the new connections and service upgrade program.

Since many new distribution system assets have an expected service life of 30 to 60 years, it is appropriate for new secondary distribution assets, including service transformers, that are installed in the near term to be able to support EV and hybrid heat pump adoption by all supplied residential customers. This will reduce the risk that assets installed in the 2028-2032 planning period will need to be replaced prematurely due to EV and heat pump adoption in the following years.

Hydro One will continue to monitor and evolve its practices in response to changing technology and customer usage patterns.

2.0 INVESTMENT DESCRIPTION

This section summarizes the activities that Hydro One undertakes under this investment, which primarily consist of the design and construction activities associated with customer connections and removals.

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, in accordance with DSC requirements. A basic connection consisting of a service layout, standard 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. For customers that require expansion of the network 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.

The net and gross capital expenditure forecasts for non-subdivision and subdivision new connections are based on forecast volumes and historic net and gross actual cost per unit plus anticipated costs to accommodate increased loads due to residential electrification. The non-subdivision large expansion project component of the new connections program is forecast based on the 2023-2025 average net and gross cost of this component, adjusted for inflation. Forecast customer capital contribution is calculated as the difference between the gross and net capital expenditure, 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 standard 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.

The net and gross capital expenditure forecast for service upgrades is determined based on forecast volumes and historic net and gross actual cost per unit plus anticipated costs to accommodate increased loads due to residential electrification. The large expansion project component of the service upgrade program is forecast based on the 2023-2025 average net and gross cost of this component adjusted for inflation. 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 the removals costs set out in Section 4.0 below.

The gross capital expenditure forecast for service cancellations is based on historic unit costs.

3.0 OUTCOMES

This investment will meet Hydro One's licence obligations to connect requesting load customers and accommodate the upgrade of existing load connections, enabling residential construction within the province of Ontario. It will also meet the need to cancel the services of requesting customers, including the removal of idle connection assets.

3.1 OEB RRF OUTCOMES

Table 4 presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 4 - Outcome Summary

Customer Focus	• Fulfill customer service requests as mandated by Section 7.2 (customer connections) of the Distribution System Code, Electricity Act, 1998, and Ontario Energy Board Act, 1998; and Hydro One's Conditions of Service and Electricity Distribution License. • Complete low and high voltage connections within five and ten business days respectively at least 90% of the time, in accordance with Section 7.2 of the DSC. • Complete customer appointments at least 90% of the time in accordance with sections 7.3 and 7.4 of the DSC. • Respond to inquiries requiring a written response within ten business days at least 80% of the time, in accordance with section 7.8 of the DSC.
Operational Effectiveness	• Contributes to compliance with Electrical Distribution Safety (O. Reg 22/04) and safety objectives by ensuring service connections are compliant with applicable requirements. • Contributes to system reliability objectives by installing assets that meet up-to-date standards and provide sufficient capacity when completing the connection request. • Removes assets when services are cancelled to mitigate safety risks
Public Policy Responsiveness	• Enables construction of new residential units in the province of Ontario.

4.0 EXPENDITURE PLAN

The investments in this ISD facilitate Hydro One's ability to meet its statutory and licence obligations under the *Electricity Act, 1998* and the Distribution System Code by responding to customer-initiated requests for connections, upgrades, and cancellations on a non-discriminatory basis. They also allow Hydro One to accommodate increasing residential load associated with electric vehicles and heat pumps while mitigating unacceptable asset loading or power quality risks.

The main factors affecting 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 17% of gross investment cost, consistent with 2023-2025 historic actuals.

Tables 5, 6, and 7 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 planning period.

Table 5 - Hydro One - Investment Expenditures[5]

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	1,055.3	1,666.7	394.8	415.6	430.9	452.0	468.5	2,161.8
Less Removals	38.2	67.3	17.5	18.7	19.7	21.1	22.2	99.2
Less Capital Contributions	182.5	307.1	65.6	69.0	71.5	75.3	78.0	359.4
Net Capital Expenditures	**834.6**	**1,292.4**	**311.7**	**327.9**	**339.7**	**355.6**	**368.3**	**1,703.3**

Table 6 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	-	5.98	1.90	2.01	2.09	Embedded in Hydro One Networks		
Less Removals		0.18	0.12	0.13	0.14			
Less Capital Contributions		1.22	0.38	0.40	0.42			
Net Capital Expenditures		**4.57**	**1.40**	**1.47**	**1.53**			

[5] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 7 - Peterborough RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	-	8.30	2.63	2.78	2.90	Embedded in Hydro One Networks		
Less Removals		0.36	0.20	0.21	0.22			
Less Capital Contributions		2.69	0.59	0.63	0.66			
Net Capital Expenditures		**5.25**	**1.84**	**1.94**	**2.02**			

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts net capital expenditures of $1,292.4M for this investment, $457.8M higher than planned. The variance reflects the higher-than-planned customer-driven work volumes, market-wide material cost escalation, and an increased scope and complexity associated with customer connection and service upgrade work.

From 2023-2027, service upgrade volumes are expected to be 36% above plan and new connection volumes are expected to be 4% above plan. Service upgrade volumes have remained consistently above plan throughout the period, while new connection volumes were influenced by fluctuations in subdivision development activity. Subdivision lots energized remained elevated in 2023 before returning to historical levels in 2024 and 2025. Overall, the higher volumes of customer-driven work increased the number of connections and service upgrades Hydro One was required to design and construct, contributing directly to higher program expenditures.

Expenditures were impacted by significant market-wide cost escalation affecting materials required to deliver this work. Distribution transformer costs increased by 40% on average, conductor, cables and wires increased by 65% on average, and distribution poles increased by 45% on average, as presented in SPF Section 1.8, Table 1. These materials are key inputs to customer connection and service upgrade work, and the increase in their cost materially increased the cost of delivering work across the program.

The scope and complexity of customer connections and service upgrades has also increased. Hydro One has experienced an increasing number of customer requests for larger electrical services that involve associated distribution system modifications. Compared with standard connections, these requests may involve additional or higher-capacity transformers, larger conductors and other distribution assets, as well as modifications or extensions to the existing distribution system. As a result, they require greater design and construction effort and a greater amount or higher capacity of material and equipment. Subdivision connections and large industrial expansions in particular are highly complex as they require more extensive distribution system work and may require coordination with developers, municipalities, road authorities, property owners and other stakeholders. The increased work scope associated with these projects contributes to a higher cost of delivering customer connection and service upgrades and, consequently, to the overall expenditure variance.

Despite increased volumes and project complexity, Hydro One continued to prioritize the timely delivery of customer connection and service upgrade work in accordance with its obligations under the Distribution System Code. These activities support residential construction, and electrification across its service territory.

The experience during the current rate period demonstrates both the level of customer demand and the investment required to deliver customer connection and service upgrade work under current market conditions. Accordingly, recent actual work volumes, material costs, and work scopes form the basis of the 2028-2032 expenditure plan.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, Hydro One plans to invest an average of approximately $340.7M per year in the New Load Connections, Upgrades, Cancellations program, for a total of $1,703.3M to connect new customers, upgrade existing services, and remove assets associated with cancelled services across Hydro One.

Volume forecasts are based on customer growth forecasts and electrification expectations developed by Hydro One’s Load Forecasting group and documented in Exhibit D-05-01. Planned costs are based on recent historical average costs, adjusted for inflation and

updated to reflect changes in design practices required to accommodate higher residential loading due to electrification.

5.0 ALTERNATIVES

The investments in this program are mandatory to comply with Hydro One's legal and regulatory obligations as identified above.

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: STATUS QUO

This alternative entails not updating residential load assumptions to reflect loading associated with the adoption of EVs and heat pump hybrid space heating systems. Under this alternative, Hydro One would continue to size new assets based on historic load assumptions, and would address resulting equipment overloading and customer power quality issues on a reactive basis. This alternative is rejected as reactive management will lead to premature replacement of new distribution assets, increased equipment failures, and degraded power quality for Hydro One's customers.

ALTERNATIVE 2: INCREASED RESIDENTIAL LOAD ASSUMPTIONS (RECOMMENDED)

Under this preferred alternative, Hydro One Distribution will update residential load assumptions to reflect the additional loading associated with EV adoption and heat pump hybrid space heating systems. This ensures that new distribution system assets that are installed to supply residential customers are appropriately sized to accommodate these electrification-related loads. This alternative is recommended as it helps avoid the premature replacement of newly installed distribution assets and supports the maintenance of acceptable power quality for Hydro One's customers.

6.0 EXECUTION RISK AND MITIGATION

Hydro One successfully connects several thousand load customers to its distribution system every year. While Hydro One has significant experience executing customer connection work, this program is inherently variable because both demand and costs are largely driven by customer-initiated requests and site-specific requirements. Actual annual

volumes may differ from forecast due to changes in customer growth, development activity, electrification adoption, and the timing of customer projects. Program costs may vary depending on the scope and complexity of individual connections or upgrades, the amount of work required, material availability, and broader market cost pressures. Hydro One manages this uncertainty through ongoing customer coordination, scheduling and prioritization of work to meet service obligations, monitoring of volumes and unit costs, and updates to planning assumptions as new information becomes available.

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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

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	9.7	9.7	9.7	10.4	10.4	49.7
Orillia RZ	0.36	0.36	0.36	Embedded in Hydro One Networks		
Peterborough RZ	0.36	0.36	0.36			

Summary:

Hydro One is required under the Distribution System Code (DSC) to make all reasonable efforts to connect eligible Distributed Energy Resources (DER), and ongoing provincial programs are expected to drive continued growth in DER connections through 2032. The forecast for DER adoption is based on historical connection data and informed by the IESO's DER Potential Study, incorporating expected increases in both renewable and non-renewable projects. The proposed investments include system upgrades necessary to safely connect DER while maintaining reliability, power quality, and equipment integrity, with cost recovery aligned to regulatory requirements. This program enables Hydro One to meet its DSC obligations and support public policy objectives related to continued DER integration without compromising system performance or compliance.

1.0 INVESTMENT NEED

The DSC requires Hydro One to make all reasonable efforts to connect DER that meet regulatory requirements. 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.

The province of Ontario has established several programs to encourage the adoption of DERs. As explained in DSP Section 3.4, these programs are expected to be key drivers of connection volumes over the 2028-2032 period. Table 1 below shows actual and forecast project volumes for the 2023 to 2027 rate period and the expected number of projects for 2028 to 2032 based on the DER forecast outlined in DSP Section 3.4.

Table 1 - DER Project Volumes

Project Type		Act/Fcst[1] 23-27	2028	2029	2030	2031	2032	Total 28-32
Non Renewable Energy Projects	Mid/Large DER	37	32	32	32	32	32	160
	Small DER	6	10	10	10	10	10	50
	Micro	40	20	20	20	20	20	100
Renewable Energy Projects	Mid/Large DER	18	16	16	16	16	16	80
	Small DER	277	285	285	285	285	285	1,425
	Micro	4,804	1,615	1,615	1,615	1,615	1,615	8,075

This investment is required 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. DER customers make capital contributions to the connection work in accordance with Hydro One's connection policy and DSC cost allocation rules. 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.

[1] "Actual" refers to Actual (2023-25) and Forecast (2026-27) volumes.

2.0 INVESTMENT DESCRIPTION

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 the following:

- the connection of the customer's tap line to Hydro One distribution system;
- build 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.

3.0 OUTCOMES

This investment will connect DERs throughout Hydro One's service area as required by the DSC, while maintaining the safe and reliable operation of the distribution system. The required investments will ensure adequate power quality, protection coordination, and distribution asset loading capacity to accommodate DER connections without compromising system reliability and safety.

3.1 OEB RRF OUTCOMES

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 established timeframes.
Operational Effectiveness	• Ensure that all upgrades are made to the latest Hydro One standards to maintain the safety and reliability of the distribution system.
Public Policy Responsiveness	• Comply with DSC Section 6.2.4 to connect qualifying DER. • Advance public policy objectives by enabling the connection of renewable energy projects in the Province of Ontario under various programs.

4.0 EXPENDITURE PLAN

Tables 3, 4 and 5 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 planning period.

Table 3 - Hydro One - Investment Expenditures[2]

($M)	Plan[3] 23-27	Act/Fcst[4] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	7.4	48.0	25.1	25.1	25.1	25.9	25.9	127.0
Less Removals	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	34.0	15.4	15.4	15.4	15.5	15.5	77.3
Net Capital Expenditures	**7.4**	**14.0**	**9.7**	**9.7**	**9.7**	**10.4**	**10.4**	**49.7**

Table 4 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	0.16	0.36	0.36	0.36	Embedded in Hydro One Networks		
Less Removals		0.00	0.00	0.00	0.00			
Less Capital Contributions		0.02	0.01	0.01	0.01			
Net Capital Expenditures		**0.14**	**0.36**	**0.36**	**0.36**			

[2] Figures presented in the tables may not sum to the totals shown due to rounding.
[3] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[4] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Table 5 - Peterborough - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	0.30	0.45	0.45	0.45	Embedded in Hydro One Networks		
Less Removals		0.00	0.00	0.00	0.00			
Less Capital Contributions		0.60	0.10	0.10	0.10			
Net Capital Expenditures		**-0.31**	**0.36**	**0.36**	**0.36**			

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be $14.0M due to higher than anticipated customer-driven connection costs and evolving market requirements. Additionally, Hydro One received a large and complex renewable energy connection request during the period that required significantly greater network investments than are typically associated with customer connection projects. Further, the introduction of the IESO's Long-Term Request for Proposals program has increased renewable generation connection activity and related expenditures.

2028-2032 EXPENDITURES

Forecast expenditures over the 2028-2032 planning period are expected to total $49.7 million. The forecast is informed by historical expenditures, the current suite of DER programs, and the findings of the Ontario Distributed Energy Resources (DER) Potential Study prepared for the IESO by Dunsky Energy + Climate Advisors, which indicates continued growth in DER adoption and connection activity. The principal drivers underlying the DER connection forecast are described in DSP Section 3.4.

5.0 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 not align with requirements under the Distribution System Code to make all reasonable efforts to connect eligible Distributed Energy Resources.

6.0 EXECUTION RISK AND MITIGATION

Hydro One connects a significant number of DER to its distribution system every year on demand. No major risk of execution 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 to meet the required service obligations. This prioritization and timing are 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

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	27.4	17.5	13.9	11.5	11.5	81.9
Orillia RZ	0.04	0.03	0.03	Embedded in Hydro One Networks		
Peterborough RZ	0.35	0.32	0.33			

Summary:

This investment funds the sustainment of wholesale and retail revenue meter installations, with the primary trigger being regulatory compliance. Hydro One currently owns, operates, and maintains approximately 1.5 million retail revenue metering devices (AMI 1.0 and AMI 2.0) and 430 wholesale meter installations. This sustainment investment ensures that Hydro One has sufficient metering and communication network equipment and resources to replace failed retail and wholesale meter installations in a timely manner to support reliable customer billing; to perform required meter sampling and reverification programs; and to perform necessary upgrades and replacements of failing metering equipment to meet regulatory requirements. It also funds investments in laboratory equipment to maintain accreditation as a licensed meter service provider and to simulate, test and evaluate new grid modernization technologies (e.g. Distributed Intelligence applications)

1.0 INVESTMENT NEED

This investment is primarily driven by regulatory compliance requirements including:

- Measurement Canada's *Electricity and Gas 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*, 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 Service Code*, setting out customer billing requirements; and
- IESO *Market Rules for the Ontario Electricity Market* (Chapter 6, Wholesale Metering, setting out requirements for wholesale metering installations).

The metering sustainment investment is comprised of two primary segments: Retail Revenue Metering compliance and Wholesale Revenue Meter compliance. Hydro One currently owns, operates, and maintains approximately 1.5M retail revenue metering devices and 430 wholesale meter installations.

The Retail Revenue Meter compliance segment ensures Hydro One has sufficient retail revenue meter equipment to replace failed meter installations in a timely manner for reliable customer billing; to perform required sampling and reverification programs in accordance with regulatory requirements, and to perform necessary upgrades to meet customer needs.

One of the key drivers of the level of investment for the retail metering sustainment program is meter failures. The program continues to invest in replacing failed AMI 1.0 meters and associated network equipment, which are failing as they exceed their expected end-of-life. The number of failures - and corresponding replacement - will progressively decline as AMI 2.0 meters are deployed. This transition will be completed by 2029, at which point all AMI 1.0 meters will have been fully replaced by AMI 2.0 meters and this replacement activity will cease. Going forward, meter replacements will be limited to AMI 2.0 failures, forecast to occur at industry average, as well as routine causes such as fire or vandalism.

Figure 1 compares the projected number of failed AMI 1.0 meters with the forecast deployment of AMI 2.0 meters, demonstrating the declining need for this investment over the 2028-2032 period.

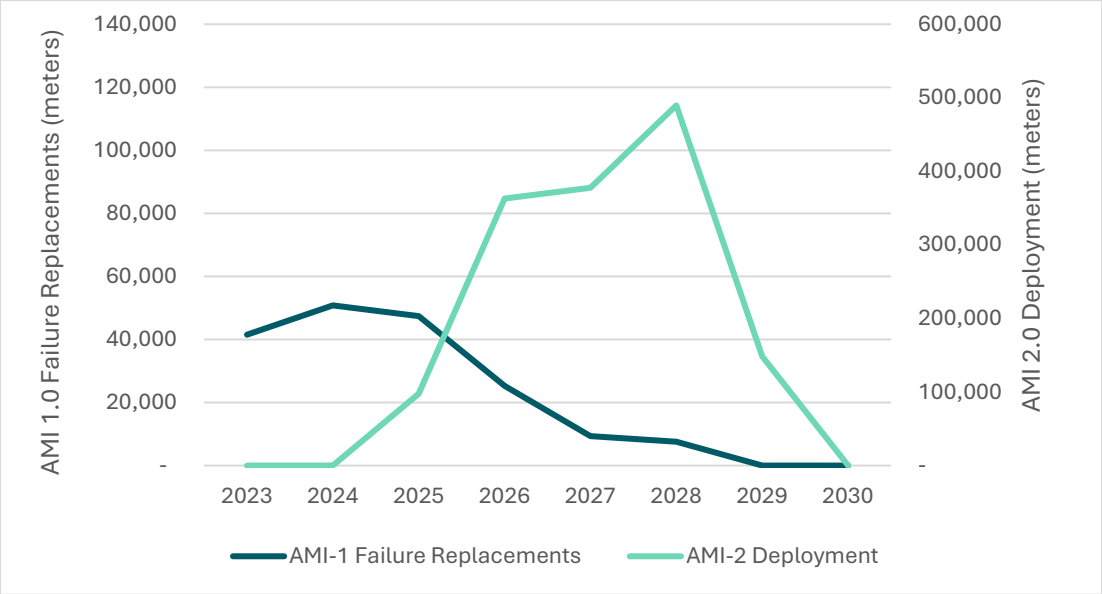


Figure 1: Projected AMI 1.0 Meter Failure Replacements and AMI 2.0 Deployment

*AMI 1.0 actual meter failure replacements for 2023-2025 and forecast for 2026-2027

The projected number of AMI 1.0 failures (blue line) is derived from actual historical failure rate trends applied to the remaining population of legacy meters in-service during each year. Historical AMI 1.0 meter failure rates have exhibited an upward trend

consistent with an aging asset base. Actual observed annual failure rates increased from approximately 2.11% in 2020 to 3.68% in 2024. The rollout of AMI 2.0 meters (orange line) reflects planned installation volumes across the 2023–2027 and 2028–2032 periods (refer to DSP Section 3.11, D-SR-12, Section 1.2). As AMI 1.0 meters are progressively replaced with AMI 2.0 meters through the ongoing deployment program, the pool of at-risk assets decreases over time, resulting in a corresponding decline in projected failure counts in later years.

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 and Gas Inspection Act*. These acts govern Hydro One's ability to bill its customers for electricity use and require all meters to be resealed at pre-determined intervals to ensure electricity use is measured 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 batch receive a seal extension. Certain meters need to be reverified and tested individually because they do not fit within the sampling program and are required to be removed for testing and replaced with new meters. Figure 2 below provides the number of meters required for sampling and reverification purposes.

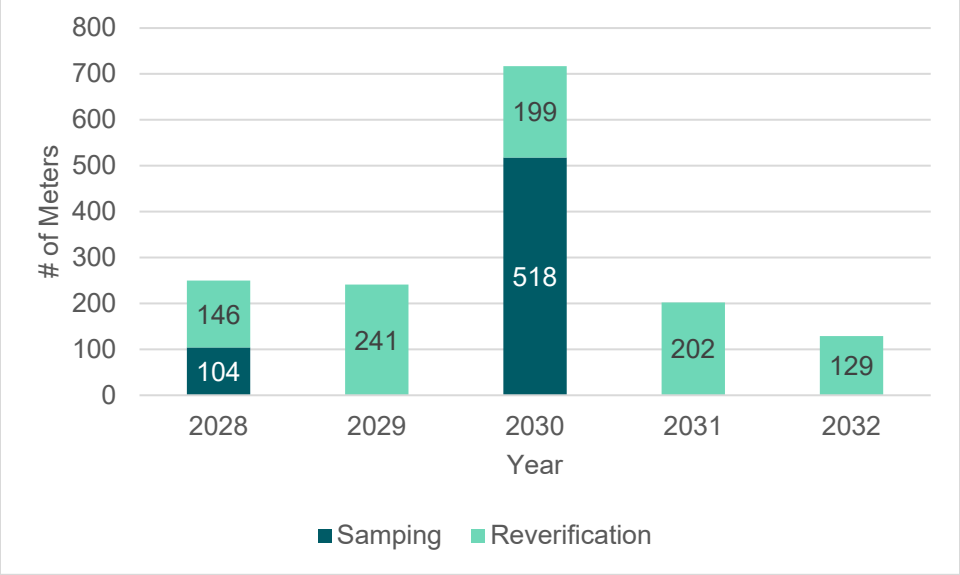


Figure 2: Sampling and Reverification Requirements 2028-2032

The Wholesale Revenue Metering Installations (WRMIs) segment funds wholesale corrective and preventative investments. Wholesale Revenue Metering Installations are employed to settle the purchase of energy, and where the point of supply is directly connected to the transmission system. 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. There are approximately 430 wholesale revenue meter installations in the service territory.

WRMI investments are broken into corrective and preventative work programs. The corrective upgrade program is driven by the need to remediate wholesale meter failures in accordance with IESO market rules. Investments in the preventative category are driven by the need to replace equipment models associated with a high risk of failure, thereby reducing the risk and cost of damage to associated equipment. Specific ABB Instrument Transformers are being prioritized for replacement as ABB ITs have caused 56% of annual wholesale IT failures (see DSP Section 3.2, Subsection 3.2.4.1).

Witness: David Paish

This investment also supports the refurbishment and, where necessary, replacement of laboratory equipment to maintain accreditation with Measurement Canada and the IESO as a licensed meter service provider. Meter test boards require annual calibration to ensure accuracy and functionality. However, even the newest test board exceeds 40 years in age, making these assets increasingly difficult and costly to maintain. As components become obsolete, repairs often require custom fabrication, increasing cost and complexity while introducing the risk of not meeting certification requirements. Where refurbishment is no longer feasible or cost-effective, equipment is replaced with modern alternatives that improve testing capacity and support a broader range of meter types. One test board replacement is planned in the 2028–2032 period.

A new investment is also required in specialized laboratory equipment to establish a dedicated Distributed Intelligence (DI) testing, simulation, and training environment. This environment will include real-time grid simulation platforms, DI-enabled smart meters, communications infrastructure, and representative grid-edge assets, such as EV charging systems and Distributed Energy Resources (DERs), along with supporting measurement, control, and safety systems. The integrated environment will function as a scaled, controlled representation of the distribution grid, enabling end-to-end validation of DI applications, interoperability testing, and realistic scenario simulation prior to field deployment. It will support both existing DI applications and use cases—through debugging and issue resolution—as well as the development and validation of future DI capabilities. This capability is necessary to reduce implementation risk, support workforce training, and ensure new technologies and use cases (e.g. managed EV charging and DER integration) are thoroughly validated before deployment. The investment supports grid modernization objectives by enhancing system reliability, safety, and planning, while enabling the efficient and effective integration of emerging customer and grid technologies.

2.0 INVESTMENT DESCRIPTION

The Metering Sustainment program funds the following investment needs over the 2028-2032 period:

- Replacing failed AMI 1.0 meters and network equipment; Replacing AMI 2.0 meters and network equipment due to normal failure causes (e.g., expected levels of standard factory failures, storms, vandalism, fire, etc.);

- Ensuring there are sufficient meters to address sampling and reverification regulatory requirements;
- Upgrading aging 12S 600V self-contained meters (as vendors are no longer supporting this form factor) with a supported meter type;
- Replacing WRMI Instrument Transformers with a high degree of failure risk (see DSP Section 3.2, Subsection 3.2.4.1);
- Upgrading non-standard meter installations to Hydro One Distribution's current wholesale and retail revenue meter standards because 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;
- Removing AMI 1.0 communication network equipment (regional collectors and repeaters) after AMI 2.0 communication network equipment is installed and becomes functional;
- Maintaining, refurbishing, and replacing aging lab equipment to ensure compliance with Measurement Canada and IESO requirements and to maintain accreditation as a licensed meter service provider for testing, verification, and sampling of meters; and
- Investing in new laboratory equipment to simulate, test, troubleshoot, evaluate, and train staff on Distributed Intelligence (DI) Applications and use cases in response to system and customer needs.

3.0 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 and Gas 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.
- Enabling grid modernization through prerequisite simulation, testing, evaluation, and training of Distributed Intelligence (DI) capabilities in meters and associated use cases, with the outcome of improved customer service and more efficient and effective operation of the distribution system.

3.1 OEB RRF OUTCOMES

Table 1 below presents anticipated benefits 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. Supporting customer service improvements (e.g., more targeted outage identification and resultant reduction in outage durations) through simulation, testing, and evaluation of Distributed Intelligence functionality and associated use cases.
Operational Effectiveness	Reducing the need for manual meter reading as a result of timely failed meter replacements and upgrades. Maintaining meter network reliability to ensure a reliable source of billing settlement data. Maintaining meter network reliability enabling distributed intelligence data for Distributed Intelligence Applications and associated use cases.
Public Policy Responsiveness	Compliance with OEB *Distribution System Code* s. 5.1 and 7.11 requirements for metering services and billing accuracy. Compliance with OEB *Standard Supply Service Code* 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.S.C 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, Chapter 6: Wholesale Metering. Supports the integration of electrification, Distributed Energy Resources, and Non-Wires Solutions through simulation, testing, and evaluation of Distributed Intelligence functionality.
Financial Performance	Contributes to financial performance by ensuring energy consumption, and purchase of wholesale energy is measured accurately and in a timely manner.

4.0 EXPENDITURE PLAN

Tables 2, 3, and 4 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 rate period.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	205.7	171.1	28.3	23.5	26.1	16.5	16.5	110.9
Less Removals	6.2	6.2	0.9	5.9	12.2	4.9	5.0	29.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**199.5**	**164.9**	**27.4**	**17.5**	**13.9**	**11.5**	**11.5**	**81.9**

Table 3 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	N/A	0.56	0.05	0.03	0.03	Embedded in Hydro One Networks		
Less Removals		0.03	0.00	0.00	0.00			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.53**	**0.04**	**0.03**	**0.03**			

Table 4 - Peterborough - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	N/A	1.43	0.37	0.33	0.34	Embedded in Hydro One Networks		
Less Removals		0.06	0.01	0.01	0.01			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**1.37**	**0.35**	**0.32**	**0.33**			

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be $34.6M (or 17%) less than plan. Program expenditures were below plan largely due to fewer meter failures than forecast. As a result, fewer meters were replaced than initially projected.

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

2028-2032 EXPENDITURES

Over the 2028-2032 rate period, forecast expenditures are approximately 59% lower than the planned amount of $199.5M and 50% lower than the forecasted expenditure of $164.9M in the 2023–2027 period. This significant decrease is driven by the elimination of the need to replace failing AMI 1.0 meters, as all are scheduled to be replaced by AMI 2.0 meters by the end of 2029. Following 2029, AMI 2.0 meters will still experience failures and require replacement, but at a much lower, steady-state rate consistent with newer assets and normal causes (e.g. vandalism, fires, etc.).

Tables 5, 6, and 7 below set out the forecast net investment costs for the 2028–2032 period, grouped by cost driver and segment. The tables also identify the allocation of these costs across Hydro One, Peterborough RZ, and Orillia RZ.

Table 5 - Hydro One Net Investment Cost by Category 2028-2032[4]

PROGRAM	2028	2029	2030	2031	2032	Total
RETAIL METERING						
Change Meter Program	8.3	4.5	4.3	4.7	4.8	26.6
Meter Conversions / Upgrades	4.2	4.6	4.3	2.7	2.7	18.5
Network Replacement Program	4.9	0.8	0.9	0.8	0.8	8.1
Grid Modernization Lab Equipment	4.2	3.2	1.1	0.0	0.0	8.6
Sample & Reverification Program	0.5	0.7	0.8	1.5	1.4	4.8
Metering Services Lab	2.2	0.5	0.3	0.3	0.3	3.5
WHOLESALE METERING						
Wholesale Preventative & Corrective	3.1	3.2	2.3	1.6	1.6	11.7
TOTAL NET CAPITAL COSTS	**27.4**	**17.5**	**13.9**	**11.5**	**11.5**	**81.9**

[4] Figures presented in the tables may not sum to the totals shown due to rounding

Table 6 - Orillia Net Investment Cost by Category 2028-2032

PROGRAM	2028	2029	2030	2031	2032	Total
RETAIL METERING				Embedded in Hydro One Networks		
Change Meter Program	0.02	0.02	0.02			
Meter Conversions / Upgrades	-	-	-			
Network Replacement Program	-	-	-			
Grid Modernization Lab Equipment	-	-	-			
Sample & Reverification Program	0.02	0.01	0.01			
Metering Services Lab	-	-	-			
WHOLESALE METERING						
Wholesale Preventative & Corrective	-	-	-			
TOTAL NET CAPITAL COSTS	**0.04**	**0.03**	**0.03**			

Table 7 - Peterborough RZ Net Investment Cost by Category 2028-2032

PROGRAM	2028	2029	2030	2031	2032	Total
RETAIL METERING				Embedded in Hydro One Networks		
Change Meter Program	0.29	0.26	0.26			
Meter Conversions / Upgrades	-	-	-			
Network Replacement Program	0.01	0.01	0.01			
Grid Modernization Lab Equipment	-	-	-			
Sample & Reverification Program	0.04	0.04	0.04			
Metering Services Lab	-	-	-			
WHOLESALE METERING						
Wholesale Preventative & Corrective	0.02	0.02	0.02			
TOTAL NET CAPITAL COSTS	**0.35**	**0.32**	**0.33**			

The factors influencing the cost of the investment include:

- The cost of material and term of procurement contracts;
- Projected replacement volumes for AMI 2.0 network equipment are based on historical replacement trends, while replacement volume projections for AMI 2.0 meters are based on a combination of manufacturer recommended failure rates (0.3%) and historical damage rates from external events such as fires, vandalism, and severe weather (0.2%);
- Sampling and reverification regulatory requirements;
- The pacing of AMI 2.0 mass meter deployment (scheduled to be complete in 2029); and

- The accessibility conditions of the area in which metering devices are being replaced.

5.0 ALTERNATIVES

With the exception of one investment, all investments within the Metering Sustainment Program are non-discretionary and required to maintain compliance with applicable federal and Ontario Energy Board (OEB) regulatory requirements. In the absence of these investments, Hydro One would be unable to maintain the required operability of its metering assets; accordingly, no reasonable or feasible alternatives were identified.

The sole exception is the discretionary investment in laboratory equipment to support grid modernization. Three alternatives were considered:

ALTERNATIVE 1: STATUS QUO (DO NOTHING)

Under this alternative, Hydro One would not proceed with the laboratory equipment investment and would instead rely on limited field validation of new and emerging technologies. This option was rejected as it would result in an unacceptable level of implementation risk associated with deploying insufficiently validated technologies into the distribution system. It would also limit Hydro One's ability to troubleshoot, debug, and resolve issues that may emerge in deployed technologies, where root cause analysis requires a controlled testing environment. The absence of such an environment would also limit the organization's ability to provide technical training for staff. Taken together, this alternative would materially impair Hydro One's ability to realize grid modernization benefits associated with Distributed Intelligence and Distribution Automation.

ALTERNATIVE 2: CONTRACTED TESTING AND EVALUATION SERVICES

Under this alternative, Hydro One would solely rely on third-party vendors or external laboratories to perform testing and evaluation activities. This option was considered but rejected as impractical due to the integrated and utility-specific nature of Hydro One's metering ecosystem, including meters, communications networks, software, and associated devices. Required testing is highly dependent on Hydro One's specific operational environment, configurations, and use cases, including cybersecurity considerations. In addition, the laboratory serves as a multi-purpose, multi-user function—supporting simulation, functional testing, use case development, troubleshooting, and

technical training—which cannot be effectively or efficiently replicated through external service providers.

ALTERNATIVE 3: ON-PREMISE LABORATORY CAPABILITY (RECOMMENDED)

This alternative involves establishing an on-premise laboratory environment to simulate, test, evaluate, and troubleshoot DI-enabled metering technologies and associated devices (e.g., distribution automation equipment) prior to field deployment. The laboratory will support end-to-end validation, interoperability testing, and technical training within a controlled environment that reflects Hydro One's specific operating conditions, systems, and cybersecurity requirements. This option is recommended as it mitigates implementation risk, supports efficient issue resolution, and enables the prudent and timely deployment of grid modernization technologies.

6.0 EXECUTION RISK AND MITIGATION

There is a risk that AMI 1.0 meters could experience failure rates exceeding original forecasts as these assets surpass their expected 15-year service life. Additionally, any change in the deployment pacing of AMI 2.0 may result in AMI 1.0 meters remaining in service beyond the originally planned replacement horizon. These risks will be mitigated through enhanced monitoring and reporting of meter failure trends, and ongoing monitoring of the AMI 2.0 project.

D-SA-05	BROADBAND
Primary Trigger:	Compliance
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	150.1	0.0	0.0	0.0	0.0	150.1
Orillia RZ	0.0	0.0	0.0	Embedded in Hydro One Networks		
Peterborough RZ	0.0	0.0	0.0			

Summary:

The investment is required for Hydro One's compliance with O. Reg. 410/22 (Electricity Infrastructure – Designated Broadband Projects), as amended in 2025 by O. Reg. 248/25 (the "Broadband Regulation"). The Broadband Regulation requires Local Distribution Companies (LDCs) to provide access to distribution infrastructure and complete "make ready" work necessary to facilitate provincially designated broadband projects. The Broadband Regulation establishes the statutory authority for the Province to require owners of electrical utility infrastructure to accommodate and/or participate in broadband expansion initiatives and, where necessary, direct utilities to perform the required work or authorize proponents to undertake work on distribution system infrastructure. This investment supports the Province's broadband expansion and Hydro One's compliance with the Broadband Regulation.

There are no planned, annual or forecast net capital expenditures for Orillia RZ or Peterborough RZ.

1.0 INVESTMENT NEED

In response to the Province's policy to accelerate broadband connectivity to underserved or unserved homes and businesses, the Broadband Regulation imposes obligations on distributors to provide access and complete make-ready work for designated broadband projects on a prescribed timeline. Hydro One's broadband program is undertaken to comply with the requirements of the Broadband Regulation.

The Broadband Regulation establishes obligations requiring distributors to provide access to their infrastructure and complete prescribed make-ready work to facilitate broadband attachments by Internet Service Providers ("ISPs"). Distribution poles were not historically designed to accommodate fibre attachments for broadband. As a result, each designated pole must be assessed to ensure it can safely support proposed fibre attachments, with any make-ready work completed before fibre installation.

This investment does not include expenditures that are addressed as part of the Joint Use and Relocation Program discussed in DSP Section 3.11, D-SA-01. Although both programs involve third-party use of Hydro One infrastructure, Hydro One manages the broadband program separately from the Joint Use and Relocation Program to ensure dedicated governance, scalable resourcing, and execution processes capable of meeting the requirements established under the Broadband Regulation. Accordingly, the Broadband Regulation does not impose requirements on Hydro One's Joint Use and Relocation Program.

2.0 INVESTMENT DESCRIPTION

To comply with the Broadband Regulation, Hydro One is required to assess attachment applications submitted by ISPs and complete any make-ready work necessary to safely accommodate approved broadband attachments. Completing make-ready work is necessary to maintain worker safety, public safety, and system reliability while meeting the requirements of the Broadband Regulation.

Hydro One assesses the scope of make-ready work required in response to an approved application submitted by an ISP. Where engineering and technical assessments determine that existing pole infrastructure cannot safely or adequately support a proposed

broadband attachment, make-ready work is required before the attachment can proceed. Such requirements may arise from the characteristics of the existing Hydro One poles, including pole height, strength or physical condition.

Make-ready is work required solely for the purpose of safely accommodating the proposed ISP attachments. Make-ready work can range from simple to complex and includes pole replacements, installation of new guying and anchoring, replacement of insulators, and raising of conductors to make space for additional attachments.

Following completion of Hydro One's make-ready work, the ISP is responsible for installing the broadband fibre attachments. Execution of the investment will leverage Hydro One employees and external contractors to meet execution timelines.

3.0 OUTCOMES

3.1 OEB RRF OUTCOMES

This investment primarily supports the Renewed Regulatory Framework (RRF) Public Policy Responsiveness and Operational Effectiveness outcomes by enabling Hydro One to comply with the Broadband Regulation. The investment also supports Customer Focus by providing a transparent and timely process for responding to eligible attachment requests from ISPs.

This investment is required to ensure Hydro One fulfills its legislated obligations under the Broadband Regulation, including the assessment of attachment applications and completion of required make-ready work. The resulting outcomes of the investment are summarized in Table 1.

Table 1 - Outcome Summary

Customer Focus	• Facilitate access to Hydro One's infrastructure through a standardized attachment review and make-ready process. • Provide timely and consistent responses to eligible ISP attachment applications.
Public Policy Responsiveness	• Comply with the requirements and timeline established under the Broadband Regulation.
Operational Effectiveness	• Assess attachment applications and execute make-ready work in accordance with applicable engineering, safety, and technical standards. • Maintain worker safety, public safety, and system reliability while accommodating broadband fibre attachments.

4.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's planned and forecast net capital expenditures for the 2022-2027 period and forecast net capital expenditures for the 2028-2032 planning period. There are no planned, actual or forecast expenditures from 2022-2027 and no forecast expenditures from 2028-2032 in Orillia RZ and Peterborough RZ.

Table 2 - Hydro One – Investment Expenditures[1]

($M)	Plan[2] 22-27	Act/Fcst[3] 22-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	1,849.5	296.0	0.0	0.0	0.0	0.0	296.0
Less Removals		121.0	18.0	0.0	0.0	0.0	0.0	18.0
Less Capital Contributions		730.1	127.9	0.0	0.0	0.0	0.0	127.9
Net Capital Expenditures		**998.4**	**150.1**	0.0	0.0	0.0	0.0	**150.1**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110. There is no OEB-approved plan for the Broadband Program.
[3] "Actual" refers to actual (2022-2025) and forecast (2026-2027) expenditures. These actual and forecast costs are recorded in the generic deferral account and are excluded from Hydro One's capital and summary tables for the historic and bridge period.

2022-2027 EXPENDITURES

Over the 2022-2027 rate period, Hydro One forecasts expenditures to be $998.4M. There is no OEB-approved 2022-2027 plan for this investment because the Broadband Regulation came into force in April 2022, when Hydro One was already in the latter stages of its 2023-2027 rate application (EB-2021-0110). In July 2022, the OEB issued an Accounting Order (001-2022) which required distributors to establish a generic deferral account to record the impacts associated with designated broadband projects. Accordingly, the OM&A costs and the revenue requirement impact for the 2022-2027 broadband forecast are recorded in the generic deferral account established under the Accounting Order. Refer to Exhibit G-01-01, Section 9 for a breakdown of the balance in the Designated Broadband Project Impacts Deferral Account.

Table 3 summarizes Hydro One's actual and forecast expenditures and volume of work for the 2022-2027 period.

Table 3 - Hydro One – Investment Expenditures 2022-2027[4]

$M	Actuals Up to 2025	2026	2027	Total
Gross Capital Expenditures	354.5	707.6	787.4	1,849.5
Less Removals	24.1	45.9	51.0	121.0
Less Capital Contributions	139.2	279.6	311.2	730.1
Net Capital Expenditures	**191.1**	**382.1**	**425.2**	**998.4**
Pole Make-ready Volumes	29,838	101,000	112,000	243,000

The actual and forecast in-service additions for the work performed from 2022-2027 are included in continuity schedules underlying the 2028 opening rate base and subsequent years (see Exhibit C-04-02 and Exhibit C-04-03). Any changes from forecast in the 2022-2027 period will be captured in the Designated Broadband Project Impacts Deferral Account.

[4] Figures presented in the tables may not sum to the totals shown due to rounding.

To support compliance with the Broadband Regulation during the 2023-2027 period, Hydro One implemented several mitigation measures to address program delivery risks associated with material availability, resource capacity, and the timely execution of make-ready work.

- **Materials Management**: During the initial implementation of the program, Hydro One identified material availability as a key execution risk due to supply chain constraints and increasing demand. To mitigate this risk, Hydro One worked with distribution partners, ISPs and suppliers to establish a coordinated procurement approach that centralized sourcing of materials. This approach improved visibility to material requirements, enhanced supply chain coordination and supported the timely execution of broadband work. Hydro One continues to use this coordinated procurement approach.
- **Resource Optimization:** In response to the non-discretionary nature of the make-ready work under the Broadband Regulation and initial uncertainty with respect to the timing and volume of the work, the company pre-qualified contractors for scalability and flexibility to perform design and construction work across the province. Additionally, Hydro One implemented a regional model which is designed to maximize resource utilization through geographic assignments of make-ready work.

2028-2032 EXPENDITURES

Hydro One forecasts expenditures of $150.1M for this investment over the 2028-2032 planning period. These expenditures are associated with the completion of make-ready work required for known ISP applications that must be completed by June 2028 in accordance with the Broadband Regulation. Approximately 40,000 poles are forecast to be made ready for ISP attachments in 2028. The capital contributions shown in Table 2 above are based on applicable provincial subsidies and ISP/customer contributions. The capital contributions for make-ready work are allocated based on Hydro One's fixed cost sharing methodology which was acknowledged by the OEB.[5]

[5] OEB Staff Letter to Hydro One Re: Fixed-Percentage Cost Sharing for Designated Broadband Projects dated July 28, 2023.

The investment described for the 2028-2032 planning period is proposed to be recorded in the Designated Broadband Project Impacts Variance Account (Account 1508) as described in Exhibit G-01-03.

5.0 ALTERNATIVES

No alternatives were considered for this non-discretionary investment because Hydro One is obligated under the Broadband Regulation to assess eligible ISP applications and complete the associated make-ready work.

6.0 EXECUTION RISK AND MITIGATION

The broadband investment is non-discretionary and required to support Hydro One's compliance with the Broadband Regulation. Hydro One's expenditures are based on the volume of make-ready work forecast for construction in 2028.

To support the safe and efficient execution of its regulatory obligations, Hydro One has implemented several technical and process improvements intended to reduce the volume of make-ready work required and improve execution timelines. For example, "Overlashing Previously Accounted For" (OPAF) is a technical policy change that allows ISPs to use existing capacity that was previously assessed and approved as part of an earlier attachment application. By leveraging previously approved capacity, OPAF reduces the amount of engineering analysis and make-ready work required, thereby supporting timely compliance with the Broadband Regulation.

Execution of the investment remains subject to the following primary risks for which Hydro One has implemented mitigation measures:

- **Permits:** Execution of broadband make-ready work may require permits from government agencies such as the Ministry of Transportation of Ontario (MTO), Conservation Authorities (CAs) and Municipalities. Permit approval timelines can vary and present a schedule risk. With support from the Ministry of Energy and Mines and Infrastructure Ontario, Hydro One has been working with the permitting bodies to establish, uphold and potentially reduce permit review timelines. These efforts include enhanced tracking, reporting, and regular review meetings to identify and resolve permitting issues.

- **Outage Management:** The volume of planned outages required to complete make-ready work may create scheduling and resource constraints. Hydro One engaged an external contractor to support outage planning, coordination, and execution, thereby increasing execution capacity and reducing schedule risk.

D-SR-01	DISTRIBUTION STATIONS DEMAND CAPITAL PROGRAM
Primary Trigger:	Asset Failure Risk
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	13.7	14.0	14.3	14.7	14.9	71.5
Orillia RZ	0.01	0.01	0.01	Embedded within Hydro One Networks		
Peterborough RZ	0.99	0.99	0.99			

Summary:

This investment involves the replacement of failing and failed station components to maintain system reliability or restore power supply to customers. The primary trigger of the investment is asset failure risk.

The investment is expected to sustain system reliability and operation by replacing failed station equipment in a timely manner which minimizes 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.

1.0 INVESTMENT NEED

Asset failures or unplanned system deficiencies associated with various distribution station assets including transformers, reclosers, switches, insulators, station batteries and chargers 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 may present safety hazards to Hydro One employees or customers near the station or close to feeders protected by station equipment.

When service interruptions related to distribution stations cannot be addressed through switching and corrective repairs, they are addressed by replacement of failed station equipment through this investment.

1.1 TRANSFORMERS

Hydro One monitors the condition of station transformers through routine inspections, annual oil sampling, and diagnostic testing. Based on the results of these inspections, an asset condition rating of “poor”, “fair”, or “good” is assigned. Hydro One manages its fleet of fair-condition transformers through corrective repairs and oil sampling as outlined in Exhibit E-03-02, Subsection 2.1.2. Poor-condition transformers are managed through a combination of corrective repairs, planned transformer replacements, and more 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 based on latest oil sample results, Hydro One will force the transformer out of service prior to the failure.

Even with proactive maintenance efforts, transformer failures cannot be eliminated. When transformer failures do occur, many customers are impacted. Service restoration for most stations requires a Mobile Unit Substation (MUS) as a temporary solution, which takes on average approximately seven hours (and in severe cases, up to 21 hours) to install before power is restored to customers. There are also external factors that cause station transformers to fail such as lightning, system faults and animal contacts. Additionally, fair and poor-condition transformers, which have elevated dissolved gas analysis scores or moisture content in oil may fail.

For example, as shown in Figure 1, the Baileys Corner DS T1 transformer suffered an internal failure in 2024, following a nearby system fault. Oil containing carbon was released on top of the transformer from a pressure relief device.



Figure 1: Failed Baileys Corner DS T1 Transformer in 2024

Hydro One categorizes distribution station transformer failures and imminent failures into the following two categories below. Transformers that require replacement are included under this investment. Transformers requiring repairs are addressed through maintenance programs specified in Exhibit E-03-02 Section 2.1.2.

- *Class 1 failures* – Station transformer failures which result in customer interruptions. Customers are without power until an MUS is installed to restore load. On average these interruptions last approximately seven hours. Approximately 61% of Class 1 distribution station transformer failures require replacement, and 39% are repairable.
- *Class 2 failures* – Station transformer failures avoided through timely corrective or capital intervention. Such intervention is triggered by oil sampling indicating that failure is imminent. 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. Approximately 28% of Class 2 transformer failures require replacement and 72% are repairable.

The number of transformer failures (Class 1) and the number of imminent failures avoided by removal of transformers from service (Class 2) between 2016-2025 in the Hydro One Rate Zone are shown in Figure 2.

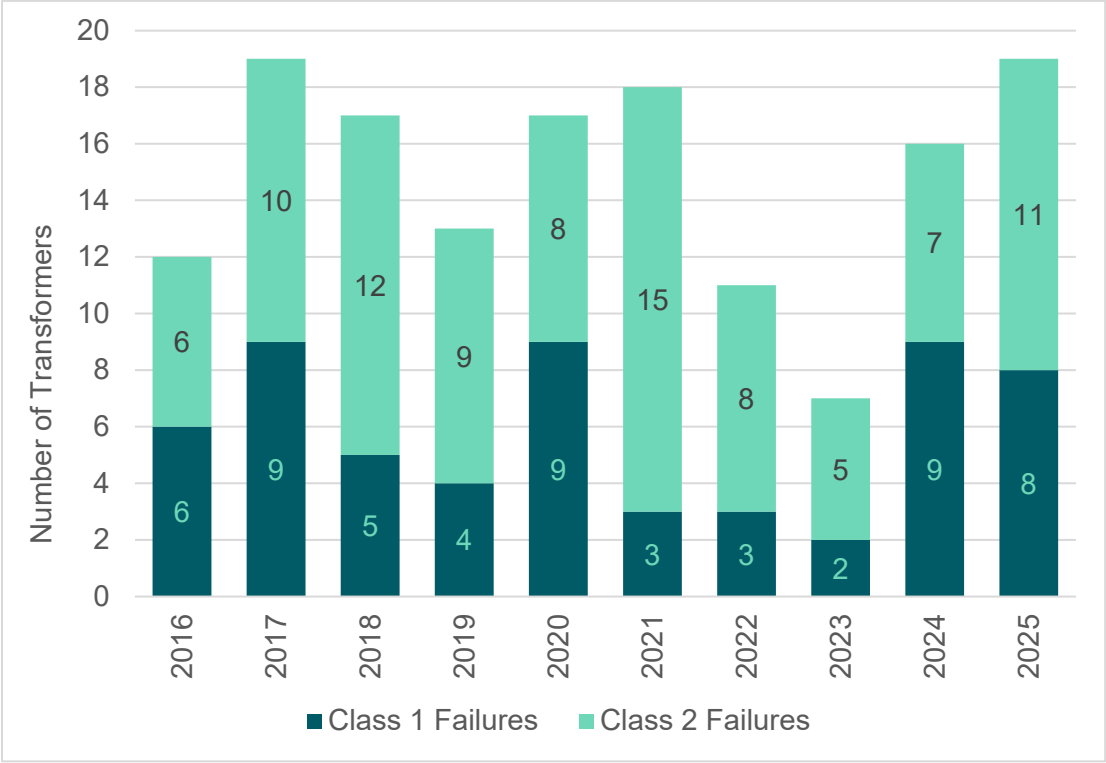


Figure 2: Failures of Station Transformers in Hydro One Rate Zone

In the Orillia RZ, no transformer failures have occurred since the acquisition in 2021. In the Peterborough RZ, one Class 2 transformer failure occurred in 2022 and one Class 1 transformer failure occurred in 2023.

For more information on station transformer performance, refer to DSP Section 3.2, Subsection 3.2.1.3. The unit costs of the transformers replaced under this program are included in the Spare Transformer Replacement Program investment (DSP Section 3.11, D-SR-13).

Witness: Paul Ankrett

1.2 MUS STRUCTURE REPLACEMENTS (ON DEMAND)

MUS Structures, including poles and cross arms, 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. As noted above, 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.

This investment addresses the replacement of poor condition MUS Structures on a demand basis. For example, Figure 3 shows a rotten MUS Structure that broke and fell on a station transformer during a storm. Hydro One has a separate planned replacement program to address verified poor condition MUS Structures over the planning period through the Planned Component Replacement Program (DSP Section 3.11, D-SR-03).



Figure 3: Broken MUS Structure at Bolton King DS

1.3 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. For example, broken insulators that support switches or buses must be replaced on demand because they can lead to falling equipment. As another example, failed station batteries or chargers that are used to operate breakers must be addressed on demand so that breakers open when required to interrupt system faults and avoid public safety hazards. Similarly, station reclosers that have failed to open or close when required to respond to system faults must be replaced on demand.

2.0 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 to maintain distribution system reliability and operation and avoid safety hazards.
- Unplanned replacement of broken, rotten or unusable MUS Structures at 44kV and 27.6kV substations, when they are required to enable demand capital work or demand corrective maintenance work.

The timing and volume of the demand station work under this investment is challenging to forecast but must be addressed quickly to mitigate customer interruptions, environmental and safety risks. Planned expenditures in this investment over the 2028 to 2032 period are forecasted based on the level of station demand capital work completed in recent years.

3.0 OUTCOMES

The replacement of failed station equipment in a timely manner benefits customers by improving reliability and minimizing outage durations. The replacement of failing station equipment before the failures occur also benefits customers by reducing service interruptions and mitigating safety risks (which is also to the benefit of Hydro One employees).

3.1 OEB RRF Outcomes

The following table presents anticipated benefits from the investment in accordance with the Ontario Energy Board's Renewed Regulatory Framework:

Table 1 - Outcome Summary

Customer Focus	• Replacement of failed or failing equipment to maintain supply to customers.
Operational Effectiveness	• Maintain distribution system reliability, operation and safety. Reduce safety risks associated with failed 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.

4.0 EXPENDITURE PLAN

Tables 2, 3, and 4 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the prior rate period and forecast net capital expenditures for the planning period.

Table 2 - Hydro One – Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	36.1	75.7	14.8	15.1	15.4	15.8	16.1	77.2
Less Removals	2.3	5.5	1.1	1.1	1.1	1.2	1.2	5.7
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**33.8**	**70.2**	**13.7**	**14.0**	**14.3**	**14.7**	**14.9**	**71.5**

Table 3 - Orillia RZ – Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	0.01	0.01	0.01	0.01	Embedded in Hydro One Networks		
Less Removals		0.00	0.00	0.00	0.00			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.01**	**0.01**	**0.01**	**0.01**			

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Table 4 - Peterborough RZ – Investment Expenditures[4]

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	4.89	1.12	1.12	1.12	Embedded in Hydro One Networks		
Less Removals		0.44	0.13	0.13	0.13			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**4.45**	**0.99**	**0.99**	**0.99**			

2023-2027 EXPENDITURES

Over the prior rate period, Hydro One forecasts expenditures for this investment to be $70.2M. Actual program expenditures for the 2023-2025 period exceeded the company's forecast due to the following factors:

a) higher-than-expected demand volume (17% higher accomplishment rate than planned);
b) the requirement to execute larger than anticipated scopes during transformer replacements to accommodate overloading experienced by transformers;
c) necessary increased transformer size (MVA) which affected 62% of the transformer replacements; and
d) the necessity to execute station footprint expansions and associated scope required to accommodate a MUS to offload equipment.

The 2026 and 2027 forecasted expenditures are based on historical actuals for 2023 - 2025 and are therefore expected to exceed planned.

2028-2032 EXPENDITURES

Over the planning period, forecast expenditures are $71.5M. The planning period expenditures for this demand program are projected based on historical actual costs and future anticipated needs. Transformer replacement and new MUS Structure installations

[4] Figures presented in the tables may not sum to the totals shown due to rounding.

are the largest drivers of the investment. The factors affecting the costs of 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 ratings of the equipment requiring replacement due to load growth.

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.

Orillia and Peterborough Investments

Minor expenditures are planned for Orillia RZ and Peterborough RZ between 2023 and 2030. Planned Peterborough RZ expenditures relate to the replacement of two failed transformers.

5.0 ALTERNATIVES

The replacement of failed or failing assets is non-discretionary. Failure to respond to these failed or high-risk assets would violate the Distribution System Code. The alternative of doing nothing 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.

To replace these assets, the equipment must be offloaded. Alternatives 1A and 1B (recommended) 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 require the use of forced outages during equipment replacement when MUS Structures are not available or cannot be used due to their condition. Under

this alternative, customers could experience power interruptions lasting several weeks while the equipment is being replaced. This is not viable. Accordingly, this alternative has been rejected.

ALTERNATIVE 1B: USE MUS CONNECTION STRUCTURES DURING REPLACEMENT OF FAILED/HIGH-RISK EQUIPMENT (RECOMMENDED)

Under this alternative, when MUS Structures are not available or cannot be used due to their condition, they will be installed or replaced as required.

This approach would allow Hydro One's 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 expenses for generator rentals. Hydro One can replace MUS poles in an emergency much faster than the time required to obtain generators, reducing the duration of customer interruptions. 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.

6.0 EXECUTION RISK AND MITIGATION

The work in this investment is unplanned. 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 demand 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 reasonable 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

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	6.2	13.8	14.9	15.2	15.5	65.6
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This investment involves the replacement of Mobile Unit Substations (MUS) that are in poor condition or have been retired following a failure of the MUS transformer. The prolonged use of poor condition MUSs increases the reliability and safety risk to Hydro One employees and the public.

This investment also involves the expansion of the MUS fleet to provide enough MUSs for station transformer failure response, and to support all planned and unplanned station maintenance and capital work.

The investment is expected to maintain the condition of the MUS fleet needed to mitigate risks to Hydro One staff and the 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.

There are no replacements or expansions planned for Orillia Rate Zone (RZ) or Peterborough RZ.

1.0 INVESTMENT NEED

For the planning period, Hydro One plans to replace MUSs that have been retired or are in poor condition and expand the MUS fleet to enable required planned corrective maintenance work and an increased capital replacement program.

MUSs are temporary, transportable substations used to maintain electrical service when a permanent substation or station equipment is unavailable. Hydro One owns, maintains and operates a fleet of 33 MUSs to support over 80% 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 including a stepdown transformer, reclosers, fuses and switches, however these components are mounted on a portable trailer. MUSs perform an integral role in the operation of Hydro One's distribution system and are utilized for:

- Emergency power restoration in the event of a transformer or other distribution station component failure; and
- Offloading distribution stations during maintenance and capital activities.

Figure 1 shows a typical Mobile Unit Substation (MUS) installation at Awenda DS.



Figure 1: MUS 50 Installed at Awenda DS

MUSs enable the following work programs by offloading station equipment during maintenance or replacement without interrupting customers:

- Distribution Stations Demand Capital Program work as outlined in DSP Section 3.11, D-SR-01;
- Distribution Station Planned Component Replacement Program work as outlined in DSP Section 3.11, D-SR-03;
- Distribution Station Refurbishment Program work as outlined in DSP Section 3.11, D-SR-04;
- System upgrades driven by load growth as outlined in DSP Section 3.11, D-SS-01, and;
- Distribution stations sustaining OM&A program work including planned preventive maintenance, demand and planned corrective maintenance work as outlined in Exhibit E-03-02, Subsections 2.1.1 and 2.1.2.

Hydro One maintains its MUS assets to ensure that an adequate, safe and reliable fleet is available to satisfy the requirements noted above. Without sufficient available and well-maintained MUSs, Hydro One would not be able to maintain reliability for customers during planned station maintenance and capital work. Furthermore, without sufficient available MUSs to support reactive stations work, outage durations could be extended by several days when equipment failures occur.

The condition profile of the current MUS transformer fleet is shown in Figure 2 below. Eight MUS transformers are in poor condition based on the results of annual oil sampling, testing and inspection.

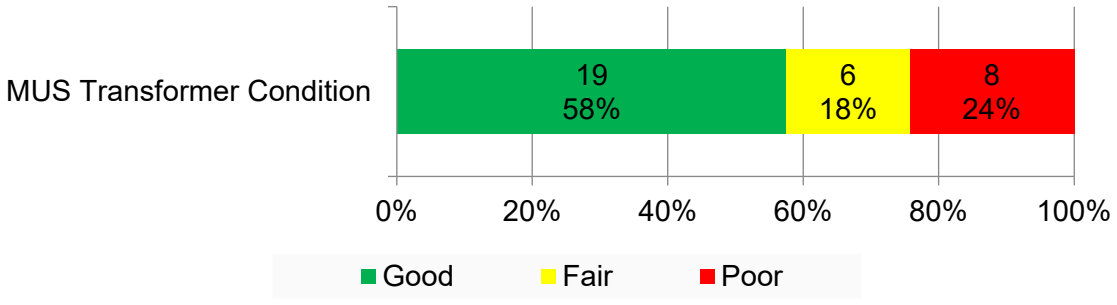


Figure 2: MUS Transformer Condition

What follows is a chronological overview of MUS failures and replacements contributing to the status of the current fleet and future MUS requirements within the planning period.

Replacement of Failed/Retired MUSs (2016-2025)

This section describes MUS replacement expenditures for the prior rate periods.

- From 2016 to 2025, five MUSs were retired following a failure of the transformer component, of which three MUSs have been replaced to date.
- In 2018, the MUS #26 transformer suffered a failure, and the MUS was retired at that time. MUS #26 was replaced by a new MUS #45 in 2019.
- In 2020, the MUS #21 transformer windings were wet. At the time the transformer was 59 years old, and the trailer was 19 years old. Hydro One decided to retire MUS #21 after attempts to source a larger replacement transformer equipped with an under-load tap-changer were unsuccessful. This MUS was replaced by a new MUS #48 in 2022.
- In 2023, the MUS #04 transformer windings were wet. Following an unsuccessful attempt to dry-out the transformer, Hydro One made the decision to retire MUS #04. This MUS will be replaced by new MUS #52 on order, for planned delivery in 2027.
- In 2024, the MUS #23 transformer suffered a failure, and the MUS was retired at that time. This MUS was replaced by a new MUS #51 in 2025.
- In 2025, the MUS #42 transformer suffered a failure, and the MUS was retired at that time. This MUS will be replaced during the 2028-2032 planning period.

Replacement of Certain MUSs in Poor Condition (Planning Period)

This section describes the MUSs and assumptions regarding their replacement which form part of the investment.

The MUS #42 transformer suffered failure, and the MUS was retired at that time. This MUS is planned to be replaced by a new MUS to be named MUS #53 planned for delivery in 2029.

MUS #34 is one of five 115kV primary voltage MUSs in the fleet. In 2022, there was a fire in the mechanical box which supplies the transformer's cooling system; Figure 3 shows the resulting damage to the mechanical box. The specialized MUS transformer which always requires cooling fans during operation, operated for an unknown period without cooling. Dissolved gas analysis (DGA) test results for the transformer have fluctuated between fair and poor over the past 10 years. Hydro One is currently working with an engineering firm to provide a replacement control box, in an attempt to restore this unit to regular operation. Previous attempts to obtain replacement parts have been unsuccessful.

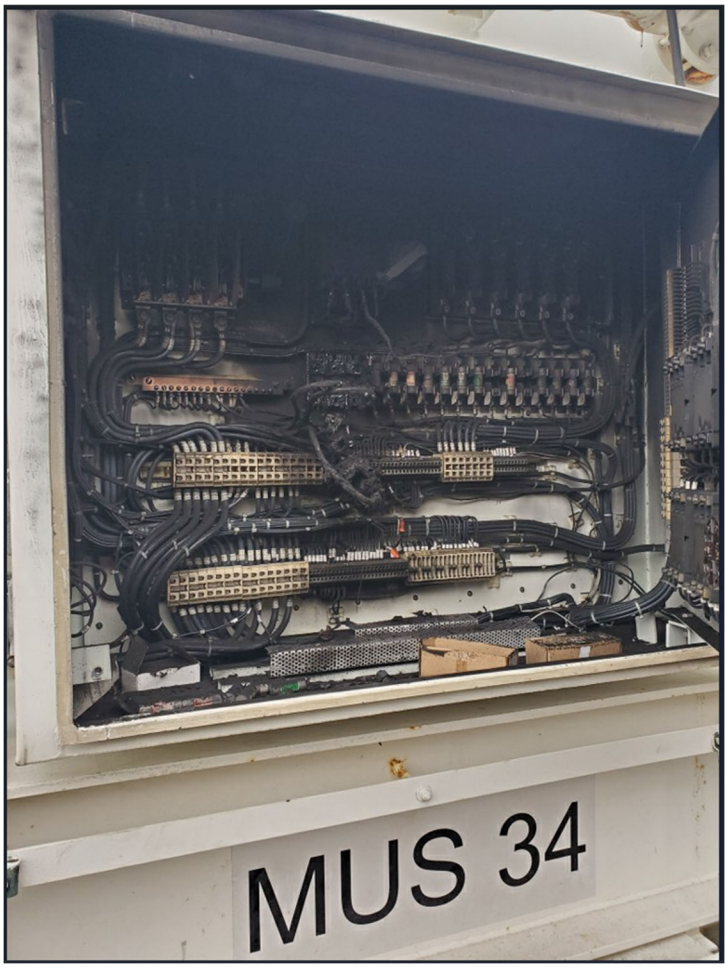


Figure 3: MUS #34 Mechanical Box Damaged by Fire

MUS #30 is the second of five 115kV primary voltage MUSs which has 43-year-old obsolete reclosers that are often non functioning. The trailer has had a significant amount of rust but was painted to briefly extend the life of this MUS.

It has become difficult to obtain parts for MUS #34 and #30. The investment assumes that one of these two units will require replacement by 2029.

MUS #24 is a 44kV and 27.6kV dual primary voltage MUS which has a 56-year-old transformer and trailer. The transformer is in poor condition based on DGA and moisture content test results. The investment assumes that this MUS will require replacement during the planning period by 2029.

Purchase of New MUSs to Accomplish the Work Program (2028-2032)

This section describes the planned purchase of new MUSs which also form part of this investment.

Hydro One currently has a fleet of 33 MUSs with the following primary voltages (HV) and multiple secondary voltages (LV):

- Five MUSs are 115kV primary voltage
- 17 MUSs are 44kV primary voltage
- Five MUSs are 27.6kV primary voltage; and
- Six MUSs are 44kV and 27.6kV primary voltage

MUSs must be available for the execution of planned and demand maintenance and capital work, and for emergency standby to support any subsequent failures.

From 2023 to 2025, the MUS fleet has, on average, enabled the execution of the following work:

- 61 planned transformer corrective repair jobs annually
- Nine unplanned (demand) transformer corrective repair jobs annually
- Two planned transformer replacements annually
- Three unplanned (demand) transformer replacements annually

- Emergency standby work (eight MUSs are kept available on emergency standby to respond to new failures when they occur).

New MUS for Planned Transformer Corrective Maintenance

Based on system needs, Hydro One must maintain a variety of different types of MUSs. The MUS transformer must align with the voltage and capacity of the station equipment it replaces during an outage. In recent years, planned transformer corrective maintenance work at approximately 17 44kV stations per year and eight 27.6kV stations per year were deferred due to MUS unavailability. These MUSs were unavailable because they had to be redeployed to support demand work following equipment failure or had to be made available on emergency standby to support any additional failures.

Hydro One forecasts needing two new 44kV MUSs to support the execution of 17 44kV corrective jobs annually; this investment includes the procurement of one new 44kV MUS for planned corrective work as partial mitigation. Additionally, Hydro One forecasts needing one new 27.6kV MUS to support the execution of eight 27.6kV corrective jobs annually; this is expected to be addressed with the replacement of MUS #42, which is discussed above.

New MUS for Planned Transformer Replacement Projects

Additionally, the investment includes the purchase of new MUSs required to support the execution of an increased number of planned transformer replacement projects compared to historic years, as detailed in DSP Section 3.11, D-SR-04 and DSP Section 3.11, D-SS-01. Table 1 below summarizes the number of planned transformer replacement projects under these investments.

Table 1 - Planned Transformer Replacement Projects

	2028	2029	2030	2031	2032	Total
D-SR-04 115kV Primary Voltage	0	0	1	0	1	2
D-SR-04 44kV Primary Voltage	0	7	17	11	11	46
D-SR-04 27.6kV Primary Voltage	0	2	6	2	7	17
D-SS-01 115kV Primary Voltage	0	2	0	0	0	2
D-SS-01 44kV Primary Voltage	1	6	2	0	2	11
D-SS-01 27.6kV Primary Voltage	2	3	0	2	0	7

An MUS can support approximately two planned transformer replacement projects annually. Based on the increase of annual planned transformer replacements over the 2028-2032 period, the Company forecasts that eight new MUSs will be required to support planned work.

44kV MUS for Planned Projects

The average over the 2023 – 2025 period was one planned transformer replacement annually. The existing MUS fleet can accommodate two planned transformer replacements annually while maintaining the historic number of annual planned transformer corrective repairs. The current 44kV MUS fleet cannot service any increase in annual planned transformer replacements beyond two units. Therefore, without this investment there would be a MUS shortfall resulting in deferral of other station work such as annual planned transformer corrective repairs above historic levels.

As illustrated in Figure 4, the average annual replacement rate will increase to approximately 12 transformers over the 2028-2032 planning period; a net increase of 11 transformers annually. Six new 44kV MUSs will be required to enable this increase in annual replacement rate. The procurement of these MUSs is included in this investment.

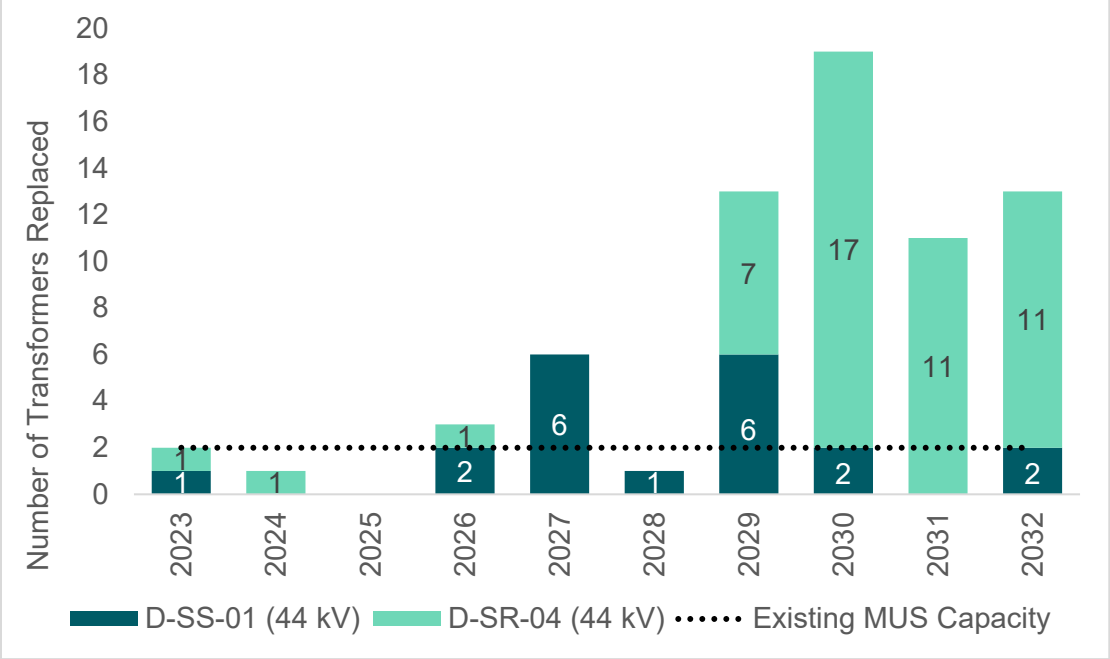


Figure 4: Historical and Planned 44kV Transformer Replacements Using MUS

New 27.6kV MUS for Planned Projects

The average over the 2023 – 2025 period was less than one replacement annually. The current 27.6kV MUS fleet can accommodate two planned transformer replacements annually while maintaining the historic number of annual planned transformer corrective repairs. Without this investment, an increase in annual planned transformer replacements will result in deferral of other station work such as annual planned transformer corrective repairs above historic levels due to MUS unavailability.

As illustrated in Figure 5, the average annual replacement rate will increase to approximately five transformers over the 2028-2032 planning period; a net increase of four transformers annually. Two new 27.6kV MUSs will be required to enable this increase in annual replacement rate. The procurement of these MUSs is included in this investment.

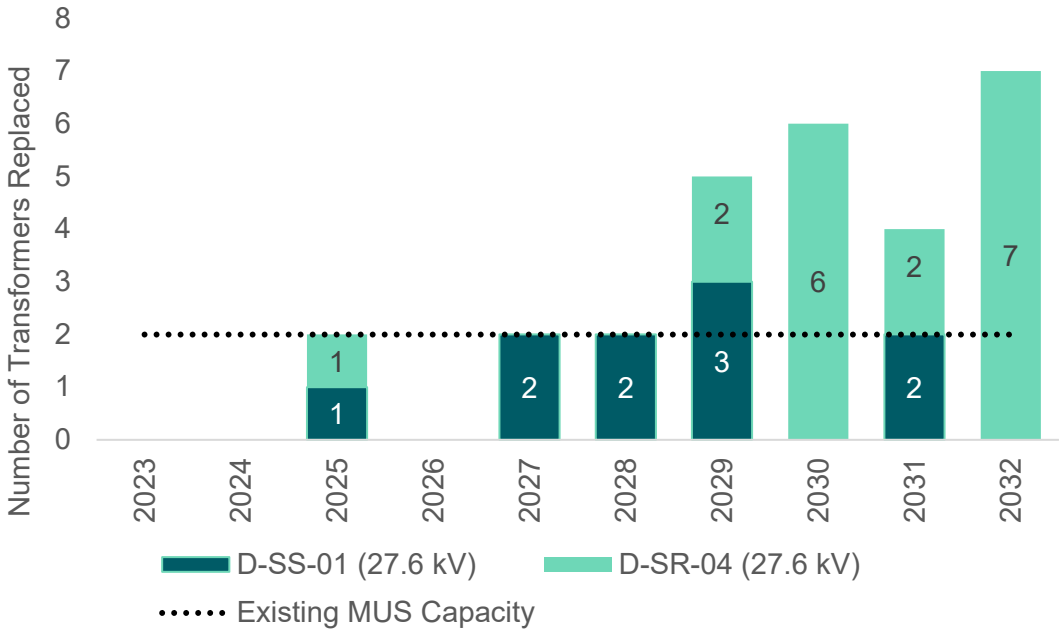


Figure 5: Historical and Planned 27.6kV Transformer Replacements Using MUS

2.0 INVESTMENT DESCRIPTION

Over the 2028-2032 planning period, Hydro One plans to perform the following activities under this investment:

- Replace MUS #42 which failed in 2025;
- Replace MUS #24 which is 56 years old, has a transformer in poor condition and is expected to fail during the 2028-2032 planning period;
- Replace one of MUS #34 and MUS #30 which have had operational problems, component failures and for which replacement parts have been difficult to obtain;
- Purchase one new 44kV MUS to reduce the annual deferral of transformer corrective repair work; and
- Purchase eight new MUSs to enable an increase of planned transformer replacement projects under DSP Section 3.11, D-SR-04 and DSP Section 3.11, D-SS-01 compared to historic years.

As outlined in DSP Section 3.2, Subsection 3.2.2.4, eight of the MUS transformer condition assessments fall into the poor condition category. If these MUSs fail, they may become unavailable if they are not replaced. MUS unavailability impacts planned transformer

maintenance and capital work programs that require MUSs to offload stations. Deferring this planned maintenance and capital work can lead to additional transformer failures and further MUS unavailability. The expenditures planned for 2028-2032 are intended to maintain the historic station transformer failure restoration time and provide sufficient MUSs to complete planned and unplanned capital and maintenance work.

Hydro One plans to replace three MUSs and procure nine new MUSs over the 2028-2032 planning period. In total, Hydro One plans to procure 12 MUSs over the 2028-2032 planning period, compared to the three MUSs forecast to be delivered over the 2023-2027 period. The forecast increase reflects a larger volume of MUS procurements.

The investment's replacement and procurement levels for the 2023-2032 planning period are summarized in Table 2.

Table 2 - In-Service Forecasts for MUS Program Work

Zone	Component Program Categories	Plan[1] 23-27	Act/Fcst[2] 23-27	Total 28-32
Hydro One	MUS Replacements	2	2	3
	MUS Transformer Replacements	6	0	0
	MUS Fleet Expansion	1	1	9
	Total	9	3	12

There are no planned replacements or expansions for Orillia RZ or Peterborough RZ.

There are no MUS transformer replacements planned for the 2028-2032 period because Hydro One has discontinued these investments due to technical limitations. Replacement transformer weight and dimension are no longer compatible with existing MUS trailers. As a result, the sole alternative is MUS replacement.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[2] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

The new MUSs will have higher MVA capacity in line with current standards and will include voltage regulation to support a higher number of stations.

3.0 OUTCOMES

The MUS 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 public.

3.1 OEB RRF OUTCOMES

Table 3 presents anticipated benefits from the investment in accordance with the Ontario Energy Board's Renewed Regulatory Framework.

Table 3 - 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 MUSs provides a cost-effective alternative to constructing redundant transformation at distribution stations across the province.

4.0 EXPENDITURE PLAN

Table 4 below summarizes Hydro One's aggregate planned and forecast net capital expenditures for the rate period and the forecast net capital expenditures for the 2028-2032 planning period. There are no planned or forecasted net capital expenditures for Orillia RZ or Peterborough RZ.

Table 4 - Hydro One - Investment Expenditures

($M)	Plan[3] 23-27	Act/Fcst[4] 23-27	2028	2029	2030	2031	2032	Total
Gross Investment Expenditures	19.4	12.0	6.2	13.8	14.9	15.2	15.5	65.6
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**19.4**	**12.0**	**6.2**	**13.8**	**14.9**	**15.2**	**15.5**	**65.6**

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures of $12.0M, which are $7.4M less than plan. The program delivered two new MUSs from 2023 to 2025, and a third new MUS will be delivered in 2027 compared to planned accomplishments of three new MUSs and six MUS transformer replacements. The reduction in the number of units deployed was partially offset by increased MUS equipment costs, particularly higher transformer costs.

The factors influencing the cost of the investment for the 2028-2032 period include:

- The number of MUSs that are being purchased each year as well as their ratings (e.g. 115kV vs. 44kV or 27.6kV high-side voltage).
- The unit prices for the MUSs. Manufacturer prices for mobile substations have increased by 75% since 2021.
- The number of MUSs required to support several planned and demand station investments and OM&A expenses as outlined in Section 1.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are $65.6M. To support the planned and demand work programs outlined above, the MUS fleet must be expanded by nine units over the 2028 – 2032 planning period. In recent years, the MUS fleet has primarily supported the demand capital program work (DSP Section 3.11, D-SR-01),

[3] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[4] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

planned component replacement program work (DSP Section 3.11, D-SR-03) and sustaining OM&A program work (Exhibit E-03-02). In 2024 and 2025, planned transformer corrective maintenance work at approximately 25 stations per year was deferred due to MUS unavailability. MUSs that were scheduled for planned station maintenance work had to be redeployed to support demand work following equipment failure or retained on emergency standby in case of any additional failures. The proposed increase in expenditures reflects the larger number of MUSs required to support station refurbishment program work (DSP Section 3.11, D-SR-04) and system upgrades driven by load growth (DSP Section 3.11, D-SS-01), in addition to the programs supported in recent years.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: REACTIVE REPLACEMENT

Under a demand replacement approach, Hydro One would wait for the MUS transformer or trailer components to fail and replace the failed MUS with a new MUS on a reactive basis. Hydro One rejected this alternative. When MUS components fail, the MUSs are unavailable until they are replaced. Unavailability of an MUS negatively impacts emergency power restoration and system reliability. Since the lead time to replace a MUS is approximately three years, the potential impact on system performance and customer reliability resulting from a demand replacement strategy would be significant. Such an approach would limit the capability of the MUS fleet to support emergency power restoration and/or capital and maintenance activities.

ALTERNATIVE 2: RENEWAL OF THE MUS FLEET

Under a renewal-only approach, Hydro One would replace MUSs with new complete units when MUS transformers or trailer components have failed.

Over the 2028-2032 period, Hydro One would perform the following activities under this alternative:

- Replace MUS #42 which failed in 2025;

- Replace MUS #24 which is 56 years old, has a transformer in poor condition and is expected to fail during the 2028-2032 period;
- Replace one of MUS #34 and MUS #30 which have had operational problems, component failures and for which it has been challenging to obtain replacement parts.

This approach would address MUSs that have failed, or are expected to fail during the planning period, or have had operational problems, or are considered end of life.

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 the 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 perform the following during the planning period:

- Replace MUS #42 which failed in 2025;
- Replace MUS #24 which is 56 years old, has a transformer in poor condition and is expected to fail during the 2028-2032 period;
- Replace one of MUS #34 and MUS #30 which have had operational problems, component failures and for which it has been difficult to obtain replacement parts;
- Purchase one new 44kV MUS to reduce the annual deferral of transformer corrective repair work; and
- Purchase eight new MUSs to enable an increase of planned transformer replacement projects under DSP Section 3.11, D-SR-04 and DSP Section 3.11, D-SS-01 compared to historic years.

Like Alternative 2, this approach will replace MUSs with new complete units when MUS transformers have failed, or when the MUS is end of life. In addition, the MUS fleet will be expanded by nine units to address planned and demand capital and maintenance work program needs.

6.0 EXECUTION RISK AND MITIGATION

The risks to this investment are the time required to execute MUS procurement processes, and the availability of vendors to manufacture and deliver the required units to Hydro One. Depending on when during 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 procurement forecasts to vendors in advance. This allows vendors to plan for and accommodate the requests and issuance of the purchase orders in a timely manner.

D-SR-03	DISTRIBUTION STATION PLANNED COMPONENT REPLACEMENT PROGRAM
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	4.4	4.5	4.4	4.5	4.5	22.3
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This investment funds the planned replacement of distribution station components in poor condition, specifically Mobile Unit Substation (MUS) connection structures, certain station switches, and certain reclosers. Poor condition MUS structures cannot be safely utilized for MUS installations at substations. Their replacement enables MUSs to be installed at stations in support of planned maintenance and capital work. It also mitigates the risk of lengthy equipment outages, allowing for timely connection of MUSs upon equipment failure.

This investment also replaces S&C model QA-48445R9 station switches that are end of life and have a history of falling when manually operated. Their replacement mitigates the safety risk associated with these switches falling near the operator.

Finally, this investment replaces station Cooper Type “L”, “E”, “4E” and “4H” oil interrupter hydraulic reclosers that are in poor condition or have exceeded the manufacturer recommended operation limit with vacuum interrupter hydraulic reclosers. These replacements mitigate the safety risk associated with 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.

There are no planned replacements or expansions planned for Orillia Rate Zone (RZ) or Peterborough RZ.

1.0 INVESTMENT NEED

Over the 2028 – 2032 period, the Distribution Station Planned Component Replacement Program addresses the need to replace three categories of distribution stations equipment:

1. Mobile Unit Substation connection structures (MUS structures) that are in poor condition;
2. Switches that are approaching end of life and have a history of failure during manual operation, creating operator safety and outage risk; and
3. Cooper Type “L”, “E”, “4E” and “4H” oil interrupter hydraulic controlled reclosers that are in poor condition or have exceeded the manufacturer recommended operation limit.

When these assets are in poor condition, they pose reliability and safety risks to Hydro One staff and customers and are therefore replaced under this planned investment. This section summarizes the need for planned investments to address these deteriorated assets.

1.1 MUS STRUCTURES

As described in DSP Section 3.11, D-SR-02, 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 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 demand station maintenance and capital work. Hydro One has MUS structures which are deteriorated and in poor condition and must be replaced. As identified in DSP Section 3.2, Subsection 3.2.2.5.2.2, 100 MUS structures are currently in poor condition. The condition profile of MUS structures is shown in Figure 1 below:

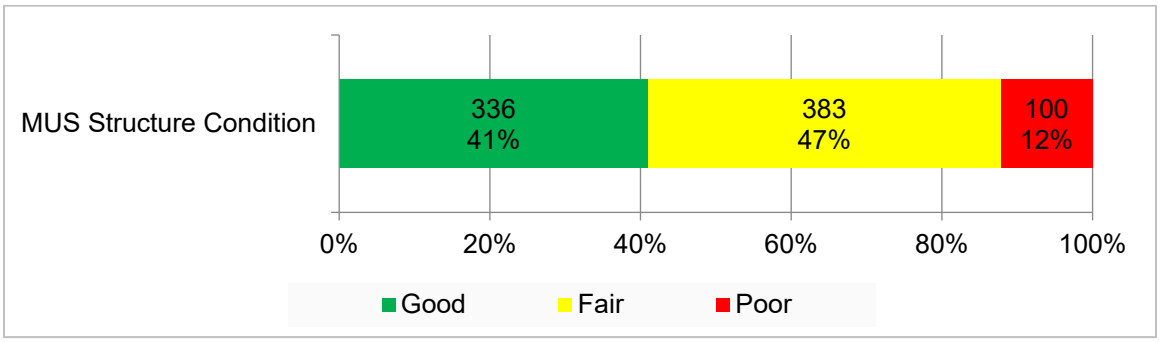


Figure 1: MUS Structure Condition in Hydro One Rate Zone

There are currently no MUS structures in the Orillia RZ and Peterborough RZ.

The health of an MUS structure is 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 safely 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 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 safely support MUS cables. Figure 2 below is an example of a MUS structure at Alex Kenyon West DS that is planned for replacement during the 2028 – 2032 period. This MUS structure has a rotten wooden pole and cross arms and is also leaning. Some MUS structures start to lean as they age, which impacts their integrity and prohibits utilization for MUS installations.



Figure 2: Leaning MUS Structure with Rotted Pole & Cross-Arms at Alex Kenyon West DS

Wooden MUS structures can also be damaged by 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. The MUS structure this stub belonged to would not be safe to use.



Figure 3: Stub from a Hollow MUS Structure that was Replaced

Rotten, hollow or leaning MUS structures cannot safely support the weight of MUS cables and are not safe to be utilized for MUS installations. 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 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 condition 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.

1.2 SWITCHES

Station switches enable the isolation of equipment such as transformers, breakers or reclosers, for the purpose of carrying out maintenance work.

Hydro One has a population of approximately 100 switches of model number QA-48445R9 manufactured by S&C Electric Company (see Figure 4). Hydro One has sustained several instances whereby these switches have failed and have fallen when manually operated. When a switch falls, it drops from above the operator causing a serious safety hazard. In addition, when these switches fall, they will result in a lengthy outage until the switch has been repaired. Further, station switches generally have an expected service life of 40 years, and the average age of these QA-48445R9 switches is currently 38 years.



Figure 4: S&C QA-48445R9 Switch on Steel Structure

Figure 5 below shows an example of a S&C QA-48445R9 switch-fuse assembly that fell at Woodlawn DS after being manually operated.

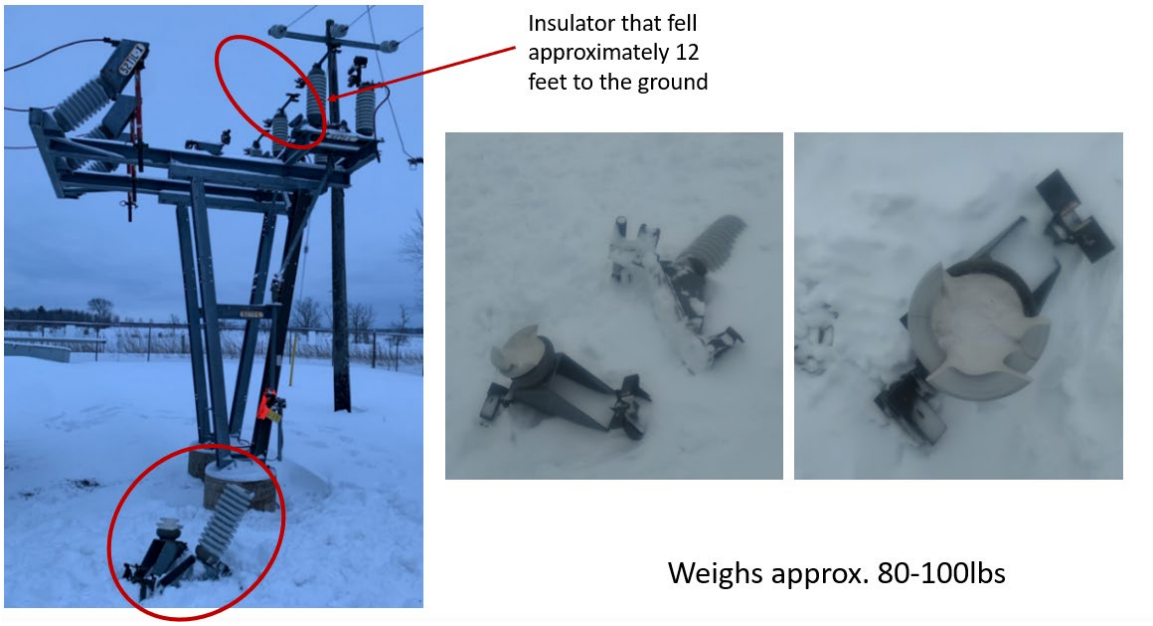


Figure 5: Broken S&C QA-48445R9 Switch-Fuse Assembly at Woodlawn DS

At Woodlawn DS, during manual operation of the switch, porcelain insulators which support the switch-fuse assembly broke, and insulators fell to the ground near the operator. This switch failure was not the first incident. Hydro One has observed this model of switch falling when operated over the past 20 years. Hydro One has historically bundled the replacements of these switches with outages for planned station transformer corrective maintenance work. Approximately 100 of these switches remain.

The replacement of these switches through this planned component replacement program allows them to be removed and replaced in a targeted and efficient manner, mitigating safety and failure risks. It would not be prudent to run these switches to failure and replace them when they fall under the Distribution Stations Demand Capital Program (DSP Section 3.11, D-SR-01) due to the safety risk associated with these switches falling on or near the operator. It would also not be prudent to solely bundle the replacement of these switches with Distribution Station Refurbishment projects (see DSP Section 3.11, D-SR-04) because Station Refurbishment projects are prioritized based on the transformer condition and not switch condition. If addressed under DSP Section 3.11, D-SR-04, the safety risks would not be mitigated because most switches would not be replaced during the 2028 – 2032 planning period.

1.3 OIL INTERRUPTER HYDRAULIC CONTROLLED RECLOSERS

Station reclosers are required to remove assets from service under fault conditions. Reclosers rapidly open and reclose in an 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 and maintain reliability, or to lock out when required for public safety. In distribution stations, 517 feeders are equipped with oil interrupter hydraulic controlled reclosers. Of these, approximately 251 or approximately 49% are Cooper Type “L”, “E”, “4E” or “4H” oil hydraulic reclosers which were built and installed in the 1970’s and are no longer supported by the manufacturer; as a result, replacement parts are no longer available. Today, Eaton manufactures “V4L”, “V4E” and “V4H” vacuum hydraulic reclosers as replacements for Cooper “L”, “E”, “4E”, and “4H” reclosers, which are more reliable and require three to four times less maintenance.

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. Because contact wear can only be observed by removal of these reclosers from service and physically taking them apart, hydraulic recloser manufacturers recommend maintenance based on the number of counter operations they undergo, and Hydro One follows the manufacturer recommend intervals.

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.

Figure 6 below represents the condition profile of the remaining Type “L”, “E”, “4E” and “4H” reclosers. Condition scores are based on counter operations and defects observed through visual inspections.

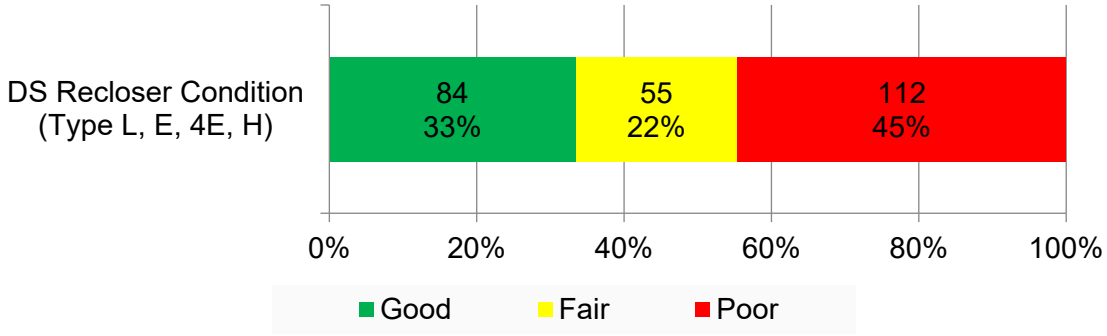


Figure 6: Condition of Type "L", "E", "4E" and "4H" Reclosers

When Cooper Type "L", "E", "4E" or "4H" reclosers have reached the manufacturer recommended operation limit prior to maintenance, Hydro One replaces these oil hydraulic reclosers with vacuum hydraulic "V4L", "V4E" and "V4H" reclosers instead of performing maintenance on them (see Figure 7 below). 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", "E", "4E" or "4H" reclosers with new vacuum hydraulic reclosers is lower in comparison to the lifecycle cost of maintaining Type "L", "E", "4E" or "4H" reclosers when manufacturer recommended operation limits are reached.

Under this strategy:

- Type "L" reclosers (64 operation limit) are replaced with Type "V4L" reclosers (248 operation limit);
- Type "E" reclosers (72 operation limit) are replaced with Type "V4E" reclosers (248 operation limit):
- Type "4E" reclosers (64 operation limit) are replaced with Type "V4E" reclosers (248 operation limit), and;
- Type "4H" reclosers (100 operation limit) are replaced with Type "V4H" reclosers (272 operation limit).



Figure 7: Type "L" Reclosers (left) and Type "V4L" Reclosers (right)

In the previous planning period, Hydro One's lifecycle strategy for the Type "E", "4E" and "4H" reclosers was to maintain them when they reached the manufacturer recommended number of operations as opposed to replacement with newer vacuum hydraulic reclosers. At that time, Hydro One's focus for capital upgrade was the Type "L" reclosers which occupied most of the oil recloser population. Hydro One has determined that Type "E", "4E" and "4H" reclosers could be efficiently replaced with vacuum hydraulic reclosers (similar to "L" reclosers) without requiring design modifications. As a result, Hydro One has expanded the program to include Type "E", "4E" and "4H" reclosers.

2.0 INVESTMENT DESCRIPTION

Over the 2028-2032 planning period, Hydro One plans to complete the following scope under this investment:

- Replace 90 poor condition MUS structures;
- Replace 75 S&C model QA-48445R9 switches, and
- Replace Type "L", "E", "4E" or "4H" oil hydraulic station reclosers for 155 feeders.

Table 1 below summarizes the MUS structure replacements, switch replacements and recloser replacements over the 2028 to 2032 planning period.

Table 1 - Number of Planned Component Replacements

Component	2028	2029	2030	2031	2032	Total
MUS Structures	18	18	18	18	18	90
Switches	15	15	15	15	15	75
Hydraulic Reclosers (Feeders)	35	35	30	30	25	155
Total Component Replacements	**68**	**68**	**63**	**63**	**58**	**320**

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 are assessed. Oil hydraulic recloser counter operations are also recorded and monitored at that time.

The replacement of S&C model QA-48445R9 switches is prioritized based on bundling this work with planned outages for transformer corrective maintenance work as much as possible, to optimize utilization of the MUS fleet.

2.1 MUS STRUCTURE REPLACEMENTS

MUS structures identified in poor condition require replacement to maintain the reliability of the system. 100 MUS structures have been evaluated to be in poor condition. Over the 2028 – 2032 planning period, 90 MUS structures in poor condition are planned for replacement. The pacing of 18 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.

2.2 SWITCH REPLACEMENTS

In distribution stations, there are approximately 100 switches of model number QA-48445R9 manufactured by S&C Electric Company that are end of life and present a falling hazard to the switch operator. This is a safety risk. Hydro One's strategy over the 2028 – 2032 planning period is to replace 15 of these switches per year under this investment.

The replacement of these switches is most effectively managed through a targeted planned component replacement program to allow these switches to be removed and replaced as quickly as possible and mitigate safety risks.

2.3 OIL INTERRUPTER HYDRAULIC CONTROLLED RECLOSER REPLACEMENTS

In distribution stations, 517 feeders are equipped with oil interrupter hydraulic controlled reclosers. Of these, approximately 251 or approximately 49% are Cooper Type "L", "E", "4E" or "4H". Hydro One plans to replace all Cooper Type "L", "E", "4E" or "4H" oil hydraulic reclosers in poor condition (certain of which have also exceeded the manufacturer recommended operation limit) with vacuum interrupter hydraulic controlled reclosers. The lifecycle cost of replacing Type "L", "E", "4E" or "4H" reclosers with new vacuum hydraulic reclosers is lower in comparison to the lifecycle cost of continuing to maintain Type "L", "E", "4E" or "4H" reclosers.

Hydro One began the replacement of Cooper Type "L", "E", "4E" or "4H" oil hydraulic reclosers with vacuum hydraulic reclosers in 2019 and these replacements have continued. Of the remaining 251 station feeders with Cooper Type "L", "E", "4E" or "4H" reclosers, 155 feeders will be upgraded to vacuum hydraulic reclosers over the 2028 to 2032 planning period as shown in Table 1. These reclosers are replaced live, and equipment outages are not required for their replacement.

Hydro One's planned replacement volumes for poor condition Type "L", "E", "4E" and "4H" reclosers under this investment are based on estimated quantities for the following:

- Annual number of reclosers with operations that have exceeded the manufacturer specified limit, observed during spring and fall station inspections.

- Reclosers with defects observed through visual inspections such as oil leaks or damaged components.
- Reclosers with hot spots identified through thermography scans performed every two years.

With reference to Figure 6 “Condition of Type “L”, “E”, “4E” and “4H” Reclosers”, 112 reclosers are currently in poor condition, and 55 reclosers are in fair condition based on number of operations, defects and hot spots observed. It is expected that most of the reclosers in fair condition will deteriorate to poor condition during the 2028-2032 planning period based on the number of operations the reclosers will experience.

Replacement of Type “L”, “E”, “4E” and “4H” reclosers that are failing to open or close when required to respond to system faults will be replaced under the Distribution Station Demand Capital Program (DSP Section 3.11, D-SR-01).

The investment’s replacement levels for the 2023-2032 period have been summarized in Table 2.

Table 2 - In-Service Forecasts for Distribution Station Planned Component Replacement Program

Zone	Component -Program Categories	Plan 2023-2027	Forecast 2023-2027	2028-2032
Hydro One	MUS Structures	75	26	90
	Switches	0	58	75
	Hydraulic Reclosers	401	145	155
	Other Small Projects	0	6	0
	Total	**476**	**235**	**320**

There are no planned replacements for Orillia RZ or Peterborough RZ.

3.0 OUTCOMES

The planned replacement of MUS structures will:

- Allow MUSs to be installed at stations to enable planned maintenance and capital work.

- Mitigate 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 10 hours.

The planned replacement of model QA-48445R9 switches manufactured by S&C Electric Company will mitigate the safety risk resulting from the potential of these switches to fall on the operator when manually operated.

The replacement of Cooper Type “L”, “E”, “4E” and “4H” oil hydraulic reclosers with new vacuum hydraulic reclosers will:

- Reduce lifecycle costs for station hydraulic reclosers, as new vacuum hydraulic reclosers have a lower lifecycle cost.
- Mitigate the safety risk resulting from reclosers failing to operate. Reclosers must be able to clear faults on downstream feeders.
- Maintain system reliability by ensuring that reclosers can clear system faults and rapidly restore power to customers.

3.1 OEB RRF OUTCOMES

Table 3 presents the anticipated benefits of the investment in accordance with the Ontario Energy Board’s Renewed Regulatory Framework.

Table 3 - 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 and replacing switches that often fall when operated.
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 lower lifecycle costs.

4.0 EXPENDITURE PLAN

Table 4 below summarizes Hydro One's aggregate planned and forecast net capital expenditures for the 2023-2027 rate period and the forecast net capital expenditures for the 2028-2032 planning period. There are no planned, annual or forecasted net capital expenditures for Orillia RZ or Peterborough RZ.

Table 4 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	22.1	11.8	4.7	4.8	4.8	4.9	4.8	24.0
Less Removals	1.7	0.9	0.3	0.3	0.3	0.3	0.3	1.7
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**20.4**	**10.9**	**4.4**	**4.5**	**4.4**	**4.5**	**4.5**	**22.3**

Table 5 - Hydro One - Investment Expenditures by Station Component

($M)	2028 – 2032 Net Expenditures	2028 – 2032 Planned Units
MUS Structures	$12.7	90
Switches	$6.5	75
Reclosers	$3.0	155
Other Small Projects	$0.1	0
Total	**$22.3**	**320**

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, actual and forecast expenditures are $10.9M, or $9.5M below plan. The program is forecast to complete 235 replacements, including MUS structures, reclosers, switches and other station components, compared to planned accomplishments of 476 MUS structure replacements and recloser replacements.

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

These expenditure and accomplishment variances are primarily attributable to investment deferrals beginning in 2025 to accommodate mandatory work. Most planned 2025 work, along with all planned 2026-2027 work under this investment, has been deferred.

In 2023 and 2024, program expenditures were in line with plan, while unit accomplishments were below plan due to higher unit costs arising from technical constraints, including unplanned yard extensions to accommodate required equipment, and unplanned battery and charger replacements.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures for this investment are $22.3M. Table 5 provides the breakdown of planned expenditures and number of units by Station Component. The factors influencing the cost of this investment are as follows:

MUS Structures

Factors influencing the cost of MUS structure replacements 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. MUS structure unit prices increased approximately 104% since 2023 due to site specific design requirements and egress pole or other required station modifications. MUS structure replacements account for approximately 57% of the expenditure in this investment.

S&C QA-48445R9 Switch Replacements

Planned switch replacement costs are driven by volume and manufacturer unit price. Switch replacements do not require engineering design for their replacement. Switch replacements account for approximately 29% of the expenditure in this investment.

Cooper Type "L", "E", "4E" or "4H" Recloser Replacements

Recloser unit prices have increased approximately 33% since 2023 due to increased material costs. Planned recloser replacements account for approximately 14% of the expenditure for this investment.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: REACTIVE REPLACEMENTS FOR MUS STRUCTURES, SWITCHES & 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. Rather, under this alternative, Hydro One would only replace these assets once they fail.

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 demand 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 S&C model QA-48445R9 switches are not replaced on a planned basis, then a switch, porcelain insulator or switch-fuse assembly could fall on the operator of the switch, which poses a safety 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 three to 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 the reasons described above.

ALTERNATIVE 2: PLANNED REPLACEMENT OF MUS STRUCTURES, SWITCHES & OIL HYDRAULIC RECLOSERS – REDUCED RATE

This alternative considers replacement of MUS structures, switches and oil hydraulic reclosers at a reduced rate compared to the recommended rate shown in Table 1.

If the MUS structure replacement rate is reduced, the population of MUS structures in poor condition will continue to increase. When transformers fail requiring the installation of a MUS, MUS installation times will be extended if the MUS structure is in poor condition and cannot be used, resulting in lengthier customer interruptions. Safety will be reduced for Hydro One staff who must install MUSs to support planned and demand work.

If the S&C model QA-48445R9 switch replacement rate is reduced, these switches will remain in-service and continue to pose a safety risk to Hydro One staff when they are required to operate these switches.

If the oil hydraulic recloser replacement rate is reduced, the population of reclosers in poor condition will increase. This will result in an increase in reclosers failing to open or close when required, will reduce system reliability and reduce public safety if reclosers are unable to interrupt system faults. These oil hydraulic reclosers will need to be maintained if not replaced, increasing annual Stations OM&A expenditures (refer to Exhibit E-03-02, Distribution Sustainment OM&A).

To summarize, replacement of components at a reduced rate compared to the recommended rate is rejected because it would increase reliability risk, safety risk, and OM&A expenditures.

ALTERNATIVE 3: PLANNED REPLACEMENT OF MUS STRUCTURES, SWITCHES & OIL HYDRAULIC RECLOSERS – ACCELERATED RATE

This alternative considers replacement of MUS structures, switches and oil hydraulic reclosers at an accelerated rate with reference to Alternative 2 and compared to the recommended rate shown in Table 1 – “Number of Planned Component Replacements”.

Replacement of MUS structures at an accelerated rate would reduce the overall number of MUS structures in poor condition. When transformers fail requiring the installation of a MUS, MUS installation times are expected to stay close to that of the recommended rate, however MUS installations for both planned and demand work overall would be safer for Hydro One staff. However, an accelerated replacement rate likely will not be achievable for Hydro One Service providers to accomplish the work.

Replacement of S&C model QA-48445R9 switches at an accelerated rate would eliminate the safety risk to Hydro One staff faster than the proposed rate. However, MUS availability will pose a limitation in accomplishing switch replacements at an accelerated rate.

Replacement of oil hydraulic reclosers at an accelerated rate may marginally improve system reliability and public safety compared to the proposed rate. However, reclosers would be replaced earlier than required resulting in some unnecessary capital expenditure.

To summarize, replacement of components at an accelerated rate compared to the recommended rate is rejected because the incremental reliability and safety risk mitigated may be marginal, MUS and outage availability to accomplish the work can become a limiting factor, and components may be replaced earlier than required resulting in some unnecessary capital expenditure.

ALTERNATIVE 4: PLANNED REPLACEMENT OF MUS STRUCTURES, SWITCHES & OIL HYDRAULIC RECLOSERS (RECOMMENDED):

Under the recommended alternative, Hydro One will replace poor condition MUS structures, replace S&C model QA-48445R9 switches to mitigate operational safety risk, and replace oil interrupter hydraulic controlled reclosers that are in poor condition or exceeded manufacturer recommended operation limits, with vacuum interrupter hydraulic controlled reclosers.

This alternative is recommended for the following reasons:

- The replacement of poor condition MUS structures allows equipment outages to be kept to a minimum, avoiding up to 10 hours of customer interruption time. The

replacement of poor condition MUS structures enables MUSs to be installed to provide for substation maintenance and planned capital work.

- The replacement of S&C model QA-48445R9 switches will reduce the safety risk of these switches, supporting insulators or switch-fuse assembly falling on the switch operator during manual operation.
- The upgrade of oil interrupter hydraulic controlled reclosers to new vacuum interrupter hydraulic controlled reclosers is an effective strategy resulting in lower lifecycle cost. Also, the maintenance requirement of vacuum reclosers is less than oil reclosers by a factor of four. Replacement of these reclosers maintains reliability and public safety as these reclosers are required to clear system faults.

This alternative maintains the safe and reliable operation of distribution stations, with component replacement rates that are achievable for service providers.

6.0 EXECUTION RISK AND MITIGATION

The main risk that can impact the completion of this investment is outage availability for the replacement of MUS structures and switches. 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 structures or S&C model QA-48445R9 switch replacements can be advanced to ensure that the overall work execution plan is not impacted. Hydraulic reclosers can be easily bypassed, so outage availability is not a concern for the recloser replacements.

D-SR-04	DISTRIBUTION STATION RENEWAL
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	10.4	55.2	101.7	72.3	89.5	329.1
Orillia Rate Zone (RZ)	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	1.08	1.70	5.43			

Summary:

This investment involves the planned renewal 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. Where appropriate, the work is undertaken in a bundled manner to also address other end-of-life components within the station. By proactively addressing poor condition transformers and associated equipment that are approaching or at end of life, this investment is expected to mitigate unplanned failures to maintain reliability of the distribution system.

1.0 INVESTMENT NEED

Hydro One owns, maintains, and operates 1,228 distribution transformers across 1,009 stations. The majority of these stations are a single transformer design with limited ability to transfer load to an alternative supply during a contingency situation. As a result, a transformer failure would result in an outage affecting numerous customers for several hours. The focus of this investment is to proactively mitigate these negatively impactful outages for Hydro One customers.

Typical assets in a station include the transformer, reclosers, switches, fuses, station structure, mobile unit substation (MUS) structure, fence, station grounding system, station service transformer, insulators, bus work, protection relays and Intelligent Electronic Devices (IEDs). A picture of the key electrical equipment inside a distribution station is shown in Figure 1. Station transformers are the primary assets within a distribution station. Maintaining their condition is essential to reliable service, making the proposed renewal investments necessary to ensure continued reliable operation.

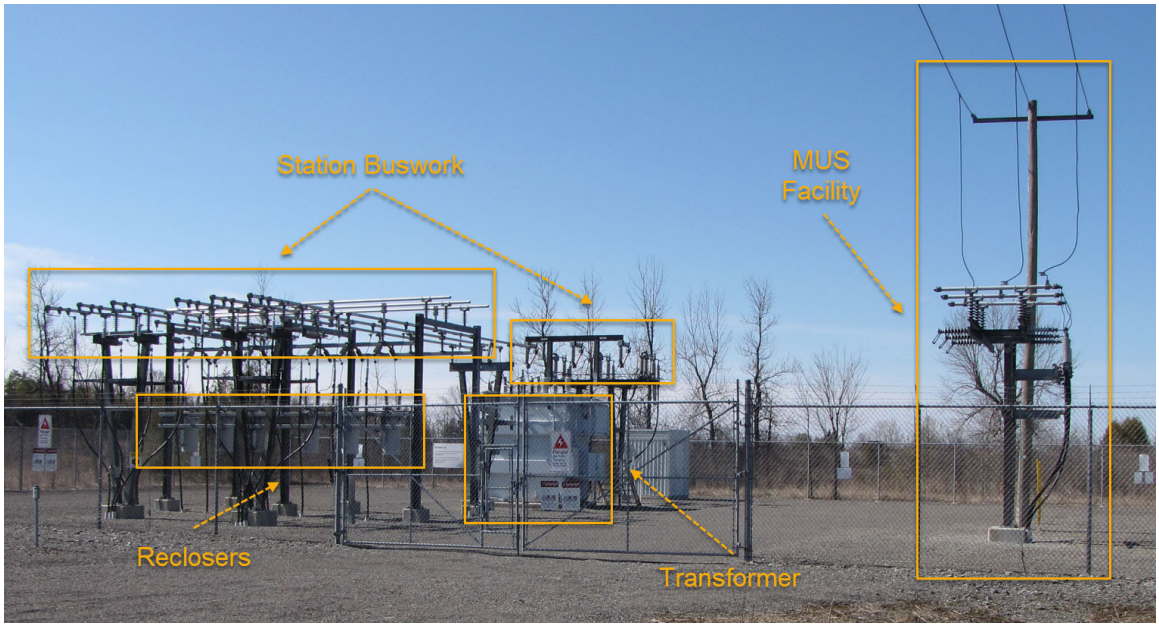


Figure 1: Distribution station with MUS facilities, near Carleton Place, Ontario

Over the life of a transformer, its internal components will degrade as a result of temperature swings due to internal and ambient conditions, switching, lightning surges,

through-faults, moisture contamination, and paper insulation degradation. Transformer condition is assessed through oil sampling, thermography (infrared heat detection), and visual inspections. These condition assessments are the best predictors of transformer failure risk due to degradation.

As described in DSP Section 3.2 Subsection 3.2.2.1, in aggregate, approximately 19%, 0%, and 36% of Hydro One, Orillia, and Peterborough Rate Zone (RZ) distribution transformers are categorized to be in poor condition (Figures 2, 3, and 4).

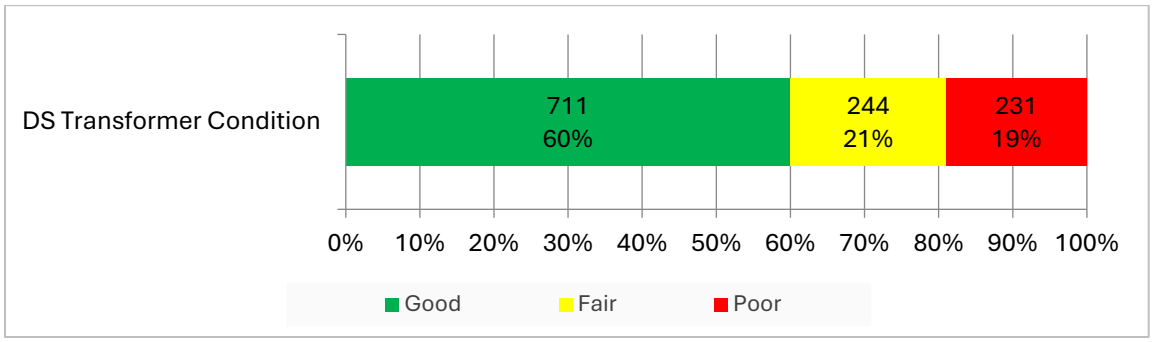


Figure 2: Condition of the Distribution Station Transformers in Hydro One

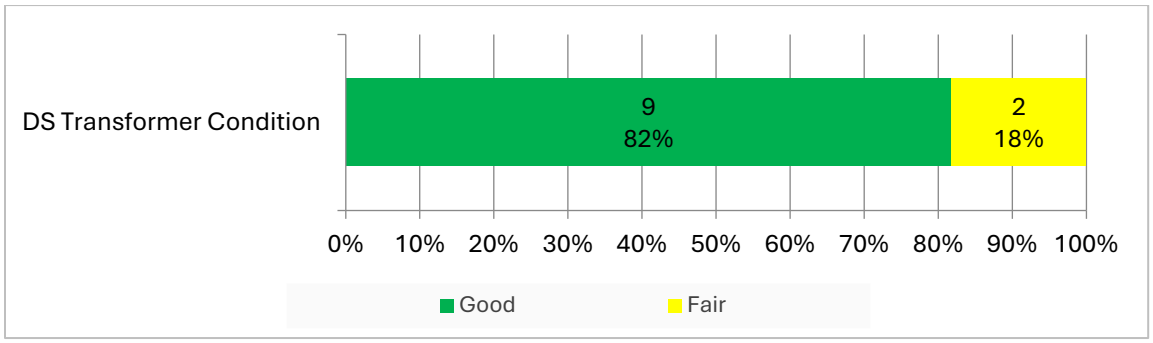


Figure 3: Condition of the Distribution Station Transformers in Orillia RZ

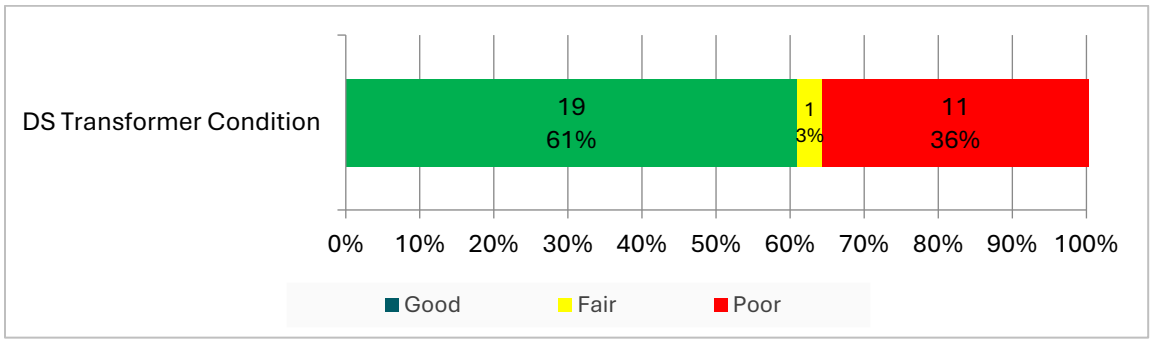


Figure 4: Condition of the Distribution Station Transformers in Peterborough RZ

Transformers in poor condition have significant deterioration or deficiencies associated with elevated risk of failure and require intervention. Depending on the nature of the deficiency, transformer age, repairability, and consequence of failure, the appropriate intervention may include planned replacement or corrective repair. Poor condition transformers need to be proactively addressed in a timely manner to mitigate the risk of transformer failures.

Hydro One utilizes two categories of transformer failures:

- **Class 1 Failures –** Failures that resulted in unplanned customer interruptions.
- **Class 2 Failures –** Imminent failures identified through regular testing that are mitigated by forced de-energization of a transformer before failure occurs.

It takes an average of approximately 7 hours to restore power for Class 1 failures, which means all customers supplied from that station would experience an interruption until power is restored by repairing or replacing the failed equipment, or installing an MUS. In severe cases, these outages can last up to 21 hours depending on the distance from the nearest available MUS to the station, and the availability and condition of the MUS structures at the station. When an MUS is not available, these outages could last days. Class 2 failures force the de-energization of a transformer but allow for the transfer of customers to an alternative supply, primarily leveraging an MUS, to avoid customer outages. The exact timing of Class 1 and Class 2 failures cannot be predicted, however,

condition data can identify transformers with elevated risk of failure that need to be proactively addressed.

Hydro One expects that if poor condition transformers are not proactively addressed, Class 1 and Class 2 failure rates would increase. Figure 5 shows the number of Class 1 and Class 2 failures experienced from 2016 to 2025.

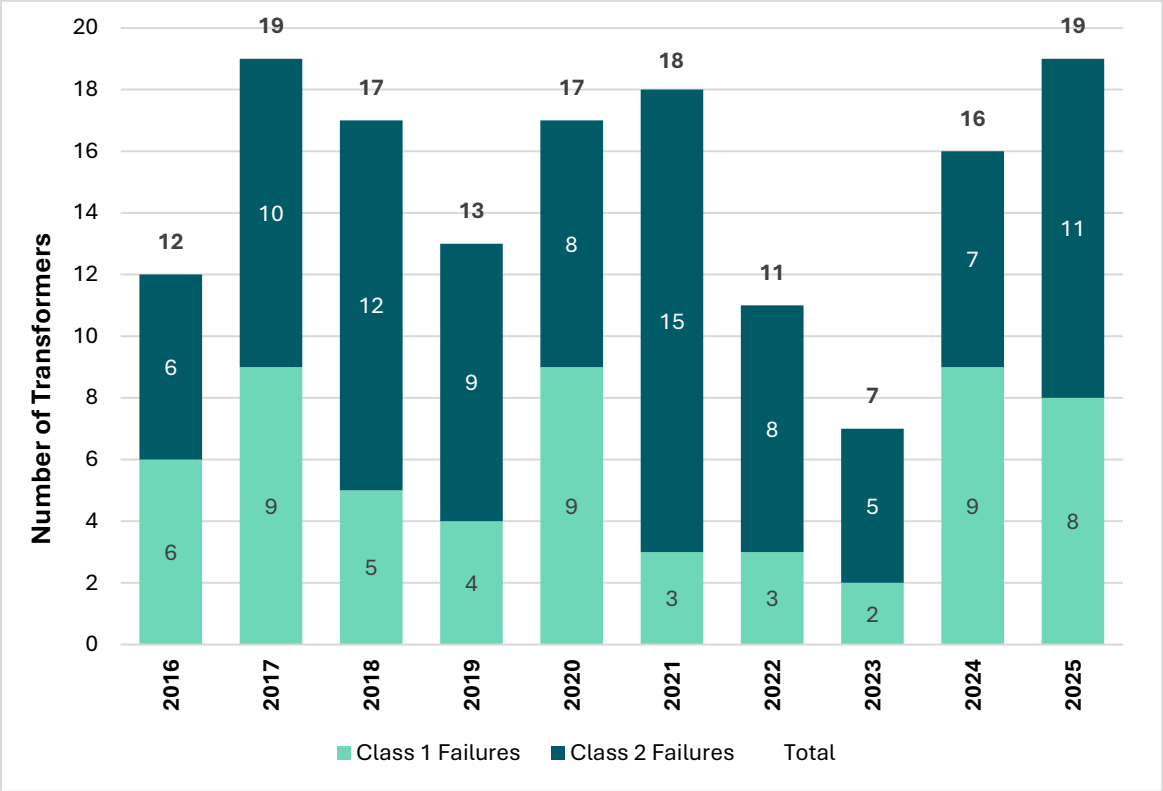


Figure 5: Class 1 and Class 2 Transformer Failures in Hydro One (2016-2025)

Within Hydro One, Class 1 and Class 2 transformer failures averaged approximately 15 units per year between 2016 and 2025. In Peterborough RZ since acquisition, one Class 2 transformer failure occurred in 2022, and one Class 1 transformer failure occurred in 2023. In Orillia RZ, no transformer failures occurred since acquisition in 2021.

Increased Class 1 and Class 2 failures can occupy the available MUS fleet, potentially resulting in significantly longer outages for customers if station transformers fail and MUS are not available. In addition to responding to failures, MUS are also deployed to facilitate

maintenance activities and to support planned capital projects, including station renewal. Since MUS units support both unplanned and planned outages, their availability is a critical consideration in responding to outages and transformer lifecycle management.

Following a transformer failure, an MUS may be required for up to 12 months while the transformer is replaced on an unplanned basis. In comparison, planned capital projects typically require an MUS for up to five months, while maintenance activities require MUS for approximately three weeks. As a result, a single unplanned deployment can displace multiple planned projects or maintenance activities. This can create a compounding reliability risk. When planned renewal or maintenance work is deferred due to MUS unavailability, poor-condition transformers remain in service longer, increasing the likelihood of failures.

Expanding the MUS fleet alone is not a sustainable solution, as it does not address the underlying deterioration of the transformer population and would not mitigate the outages from occurring.

Poor Condition Transformer – Maintenance vs Replacement

As outlined in DSP Section 3.2, subsection 3.2.2.1 Transformer Lifecycle Strategy, poor condition transformers are considered for corrective maintenance or replacement on a case-by-case basis. This decision is driven by factors such as overall transformer condition, age, and magnitude of corrective work. Corrective maintenance may be economically justified where it is expected to provide a sufficient extension in the transformer's life.

Younger transformers in poor condition are typically candidates for corrective maintenance. Performing corrective repairs on younger transformers normally allows them to reach their 50-year Expected Service Life (ESL). Transformers approaching or beyond their 50-year ESL in poor condition are typically candidates for replacement due to the limited life extension that is expected from corrective maintenance.

Candidate transformer replacement needs are reviewed alongside other investment needs to identify overlaps and coordinate proposed solutions. System upgrades driven by

load growth, as detailed in DSP Section 3.11 D-SS-01, address distribution station transformer capacity constraints and can also resolve asset condition needs. Where a planned load growth investment is required before the condition-driven replacement need and its recommended solution fully addresses the transformer condition, the investment proceeds under D-SS-01 and no separate distribution station renewal investment is included in this ISD. Conversely, where the condition-driven transformer replacement need arises before the planned load growth investment, the replacement proceeds under this ISD while considering future load growth requirements. Where appropriate, the replacement transformer is sized to meet future load growth needs, thereby avoiding the need for a subsequent transformer replacement when the load growth materializes.

Based on the above considerations, 86 of the poor condition transformers have been identified as replacement candidates as part of Distribution Station Renewal investment. The Distribution Station Renewal program will address 80, 0 and 6 poor condition transformers in Hydro One Networks, Orillia RZ and Peterborough RZ, respectively.

Guidehouse and First Quartile Benchmarking Report

Guidehouse and First Quartile completed a benchmarking study of Hydro One's Distribution Station Renewal program against participating comparator utilities (DSP Section 3.3 Attachment 2). The study found that Hydro One's approach to planned distribution station equipment inspections is generally consistent with peer utility practices. It also identified that Hydro One's distribution transformer fleet is older than those of comparable utilities, with an average age of approximately 43 years versus a peer average of approximately 35 years. In addition, Hydro One's historical (2023-2024) and planned transformer replacement rates (2025-2029) are below the average rate reported by the utilities that provided comparable replacement data.

These findings indicate that transformer replacements have not kept pace with asset aging, increasing the need for renewal investment. As described in section 4.0 below, transformer renewal investments were deferred in 2023-2027. Hydro One plans to continue transformer renewal investments from 2028-2032 to address the poor-condition assets. Over this period, Hydro One plans to replace on average 1.4% of the transformer population on an annual basis to help mitigate risks associated with an aging fleet.

The study also reported that Hydro One's average transformer loading is the highest amongst the average transformer loading reported by the comparison group of utilities that provided loading data (DSP Section 3.3 Attachment 2, p. 5). This result partly reflects the radial configuration of Hydro One's distribution system, the limited opportunities to transfer load between stations serving long feeders and the reliance on MUS. However, sustained higher loading increases thermal stress, accelerates transformer deterioration and reduces remaining service life. Hydro One's average transformer loading increased from approximately 67 percent in 2020 to 75 percent in 2025 in reference to nameplate. This increase in loading is expected to further stress the transformer fleet and contribute to a more rapid deterioration in asset condition over time.

2.0 INVESTMENT DESCRIPTION

The proposed plan within this station renewal program will address 86 poor-condition transformers identified for replacement across 81 distribution stations, averaging approximately 16 distribution stations per year over the five-year planning period, as shown in Appendices A and C.

For each transformer replacement candidate, Hydro One considers the existing station configuration, condition of other station components, and load forecast needs to develop an appropriate solution on a case-by-case basis. The selected solution mitigates the transformer risk while balancing the needs of the system in a cost-efficient manner. This evaluation includes consideration of the following station renewal options:

- **Transformer replacement** involves replacing the existing poor condition transformer with a suitably sized unit while completing only minimal station modifications. Most suitable when all other station equipment are in acceptable condition and does not require replacement.
- **Full or partial station rebuild** requires an entire or partial redesign of the station which consists of replacing the transformer unit with a suitably sized unit and replacing other poor condition station assets. Rebuild may include supporting facilities such as, bus work, additional feeder positions, MUS connection facilities,

telemetry and control infrastructure, and expanding the station footprint to accommodate the new design.

- **Pad-mounted Distribution Station (PDS)** is a smaller station, centered around a smaller transformer with supporting pole-line work. This option is intended to be utilized in areas with limited forecasted load growth.
- **Station decommissioning via load transfers** can be utilized in areas where nearby assets have sufficient available capacity to service customers currently supplied by the station targeted for removal.
- **Station decommissioning via voltage conversion** can be utilized in areas where an adjacent higher voltage system is in close proximity and has adequate capacity to accommodate load from the decommissioned station. This is in contrast to the Voltage Consolidation investments proposed in DSP Section 3.11, D-SR-17, whereby the voltage conversion is proposed to standardized area voltage.
- In some cases, a **hybrid solution** that incorporates elements of options described above may be the preferred option.

When the identified station renewal investment is a 4.16kV transformer in poor condition, it will be replaced with a higher voltage transformer for the purpose of voltage consolidation. The transformer replacement scope is captured under this investment, while the additional work associated with voltage conversion is captured under DSP Section 3.11, D-SR-17.

3.0 OUTCOMES

3.1 OEB RRF OUTCOMES

Table 1 below 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 reliable operation of the distribution system by addressing poor condition station equipment in an integrated and appropriate manner • Increase operational efficiencies by eliminating underutilized assets where practically feasible and unifying operating voltage • Where appropriate, bundle other station components in poor condition as part of renewal work

4.0 EXPENDITURE PLAN

Tables 2, 3, and 4 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecasted net capital expenditures for the 2023-2027 rate period and forecasted net capital expenditure for the 2028-2032 planning period.

The following tables capture Life Cycle Optimization (DSP Section 3.11, D-SR-11) and Station Renewal investments (DSP Section 3.11, D-SR-04) for the 2023-2027 period. For the proposed rate period (2028-2032), both these investments were combined into Distribution Station Renewal Investments (DSP Section 3.11, D-SR-04).

Table 2 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	99.3	31.8	10.4	60.4	114.6	80.1	101.7	367.1
Less Removals	10.0	3.5	0.0	5.2	13.0	7.8	12.1	38.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**89.3**	**28.3**	**10.4**	**55.2**	**101.7**	**72.3**	**89.5**	**329.1**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110. This includes all investments within DSP Section 3.11, D-SR-11 and DSP Section 3.11, D-SR-04 from Proceeding EB 2021-0110.
[3] "Act" refers to Actual (2023-25) and "Fcst" refers to Forecast (2026-27) expenditures. This includes all investments within DSP Section 3.11, D-SR-11 and DSP Section 3.11, D-SR-04 from Proceeding EB 2021-0110.

Table 3 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	0.36	0.00	0.00	0.00	Embedded in Hydro One Networks		
Less Removals		0.06	0.00	0.00	0.00			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.30**	**0.00**	**0.00**	**0.00**			

Table 4 - Peterborough RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	1.18	1.33	1.70	6.75	Embedded in Hydro One Networks		
Less Removals		0.06	0.25	0.00	1.32			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**1.12**	**1.08**	**1.70**	**5.43**			

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be $28.3M. This is $61.0M or 68.3% lower than the Plan of $89.3M. On a volume basis, this includes 8 material investments, relative to 46 planned. The variance reflects lower expenditures and was driven primarily by reprioritization in response to emerging system needs. More specifically, actual expenditures differed from plan due to changes in work volumes and timing. In addition, investment costs evolved over the 2023-2027 rate period due to unexpected cost increases for equipment including power transformers and construction costs as detailed in SPF Section 1.8, subsection 1.8.3 and 1.8.2, respectively. As a result, costs for completed investments were higher than anticipated.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are $329.1M. As outlined in Section 2.0 above, the proposed expenditures comprise of addressing 86 station

transformers through the various renewal options. Replacement cost estimates have considered recent actual and expected project material and labour costs.

A range of factors may influence the final cost of station projects within this investment. These include the number of transformer units required at each station and their associated capacity (MVA), the need for transformer voltage regulating equipment, and the primary and secondary voltage levels of the transformers and related station equipment. Additional cost drivers include the number of feeders emanating from each station, the quantity and type of protective devices required, and the applicable station design standards. Project costs may also be affected by the extent to which existing station structures can be reused or refurbished, the amount of underground infrastructure required including grounding systems, and the potential need for additional land acquisition. External factors such as remediation requirements, supply chain disruptions, and tariffs may also impact the overall project costs.

Hydro One anticipates initiating design work for station renewal activities identified in Appendices A, B and C in 2028, starting with units identified with highest risk of transformer failure and largest customer impact. The projects identified in this investment will progress through estimating, detailed engineering, and construction phases. The expenditure reflects the pacing of investments through the natural sequencing between engineering design and construction activities. In 2029, expenditures increase for both construction activities for the units designed in 2028 and initial design work to begin for subsequent units. The expenditures in the following years will continue with design work that aligns with construction activities for renewal projects until 2032.

The tables in Appendices A, B, and C outline project specifics for each respective rate zone. 23 material investments in the Appendix A have coordinated investments within Voltage Consolidation as detailed in DSP Section 3.11, D-SR-17.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended Alternative 3.

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENTS

To Address Failed Transformers on a Reactive Basis

This alternative relies entirely on replacing distribution station transformers only after failure occurs. Under this approach, no proactive renewal work would be undertaken.

A reactive replacement strategy would significantly increase the risk of customer outages and the demand on Hydro One's MUS fleet. If MUS become unavailable due to increased failures, customers could experience multi-day outages. Moreover, MUS availability for other planned work is inherently reduced. In addition, reactive intervention addresses only the failed transformer and does not provide an opportunity to replace other deteriorated station components as part of a coordinated planned station renewal, resulting in a continued reliability risk.

For these reasons, this alternative is not considered a prudent approach and is not recommended.

ALTERNATIVE 2: PLANNED STATION RENEWAL AT REDUCED PACE

To Address Approximately 60 Transformer Renewal Candidates

This alternative proposes the renewal of approximately 60 transformer renewal candidates with the highest customer impact.

By replacing these transformers, this alternative would reduce the risk of customer outages associated with transformer failures for a portion of the identified renewal candidates. The work will be bundled with the replacement of other deteriorated components where appropriate. However, this alternative will not address all identified renewal candidates. The remaining transformers will continue to operate with an elevated risk of failure and will likely require reactive intervention similar to Alternative 1. As a result, this approach will expose customers to increase risk of outages and increase demand on the MUS fleet.

While this alternative provides a reduction in risk compared to a fully reactive approach, it does not address all the identified renewal. Additionally, Customer Engagement results detailed in SPF Section 1.6 Attachment 1, p.546-548 indicated limited support for this

approach, with 23% of the respondents favoring this level of investment. This alternative is not recommended.

ALTERNATIVE 3: PLANNED STATION RENEWAL AT PROPOSED PACE (RECOMMENDED)

To Address All 86 Transformer Renewal Candidates

This alternative proposes the proactive renewal of all 86 currently identified transformer renewal candidates during the planning period. By addressing all identified renewal candidates, this alternative substantially reduces the risk of customer outages associated with transformer failures. The work will be bundled with the replacement of other deteriorated components where appropriate.

This alternative represents a balanced approach between proactive asset renewal and prudent investment levels. It addresses all the currently identified transformer renewal candidates while reducing reliance on reactive interventions and preserving MUS availability for other planned and unplanned outages. In doing so, it reduces customer exposure to prolonged outages from transformer failures.

Customer Engagement results, detailed in SPF Section 1.6 Attachment 1, p. 546-548, indicated that 49% of respondents supported addressing approximately 90 transformer renewal candidates, aligning closely with the scope of this alternative. Alternative 3 addresses all currently identified transformer renewal candidates, effectively managing asset risk and reducing customer outage exposure. This alternative is recommended.

ALTERNATIVE 4: PLANNED STATION RENEWAL AT ACCELERATED PACE

To Address Approximately 120 Transformer Renewal Candidates

This alternative proposes the renewal of all transformer renewal candidates included in Alternative 3, as well as additional poor condition units that are planned to be managed through corrective maintenance.

Compared with other alternatives, this approach would provide the greatest reduction in overall transformer failure risk and potential customer outage mitigation. The work will be bundled with the replacement of other deteriorated components where appropriate.

However, the incremental benefits achieved beyond Alternative 3 are expected to diminish relative to the additional investment level required. Many of the additional transformers included in this alternative are expected to be adequately managed through corrective maintenance activities. This approach would also place greater demand on available MUS resources to support the increased volume of planned station renewal work.

Customer engagement results, detailed in SPF Section 1.6 Attachment 1, p. 546-548, did not support this accelerated investment pace, with 28% of the respondents favoring this alternative. While this alternative delivers the highest level of risk reduction, the incremental benefits do not justify the additional costs when compared with Alternative 3. This alternative is not recommended.

6.0 EXECUTION RISK AND MITIGATION

Table 5 below identifies the risks that can impact the feasibility of station renewal projects and their associated mitigation strategy.

Table 5 - Risks and Mitigations

Execution Risk	Risk Mitigation
Real estate acquisition challenges for the proposed station site, including land availability, market valuation, and seller expectations.	Managed by clearly defining station requirements early and engaging Real Estate team at the onset to negotiate acquisition timeline and pricing to align with project in-service dates.
Potential environmental remediation requirements at site or impacts related to construction near lands of cultural significance.	Early involvement with the Environmental Services team during the initial design phase will identify environmental constraints and sensitive cultural lands of significance.
Unexpected cost escalations, including broader industry-wide cost pressures, as detailed in SPF Section 1.8	Cost risks are mitigated through multiple controls: • Supply Chain collaboration with vendors to establish bulk and long-term pricing contracts for competitive and predictable costs • Project Development to consistently work with internal and external stakeholders to bundle similar design and construction projects to capture economies of scale
Limited availability of MUS for planned station renewal due to increased transformer failures or competing deployment of MUS for other initiatives, such as Load Growth investments (DSP Section 3.11, D-SS-01), and Distribution Sustainment OM&A (Exhibit E-03-02 Subsection 2.1.2)	Timely release of projects to execution phase enables Hydro One to properly plan and schedule MUS and related resources to reduce risk of delays and cascading impacts to future planned projects
Supply Chain disruptions and extended lead time for critical components, such as, but not limited to, power transformers and electronic equipment, which may jeopardize the project in-service date if materials are delayed.	Frequent communication between Supply Chain and vendors on material lead times, combined with ability to pre-order known long lead materials will improve the likelihood that critical components are available when required.

1 **APPENDIX A - DESCRIPTION OF HYDRO ONE INVESTMENTS**

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
Alexandria Kenyon West DS*	SR-04.1	Replace existing 3 x 2.00MVA 44.00-4.16kV transformers with 5.00MVA unit	0.0	0.5	7.1	0.0	0.0
Anderdon DS	SR-04.2	Replace existing 2.00MVA 27.60-8.32kV transformer with 5.00MVA unit	0.0	0.5	3.3	0.0	0.0
Arnprior Madawaska DS*	SR-04.3	Replace existing 2.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.0	0.5	3.3	0.0	0.0
Bancroft DS #2	SR-04.4	Replace existing 6.00MVA 12.47-12.47kV transformer and associated transformer with 10.00MVA unit	0.0	0.5	3.4	0.0	0.0
Bayridge DS	SR-04.5	Replace existing 5.00MVA 44.00-8.32kV transformer with 10.00MVA unit	0.0	0.0	0.6	3.4	0.0
Beechwood DS	SR-04.6	Replace existing 5.00MVA 44.00-8.32kV transformer with 10.00MVA unit	0.0	0.0	0.0	0.6	3.5
Belmont DS	SR-04.7	Refurbish existing 3 x 3.60MVA 27.60-8.32kV transformers with 5.00MVA unit	0.6	1.6	4.7	0.0	0.0
Berwick DS	SR-04.8	Replace existing 3.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.6	3.5
Blyth DS	SR-04.9	Replace existing 3.00MVA 27.60-8.32kV transformer with 7.50MVA unit	0.0	0.0	0.0	0.6	3.5
BrockVille Centennial DS	SR-04.10	Replace existing 10.00MVA 44.00-	0.0	0.0	0.6	3.4	0.0

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
		8.32kV transformer with 10.00MVA unit					
BrockVille Park DS T1*	SR-04.11	Replace existing T1 2.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
BrockVille Park DS T2*	SR-04.12	Replace existing T2 3.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6
Brookside DS	SR-04.13	Convert existing 5.00MVA 44.00-8.32kV station to PDS with 3 x 3.00MVA units	0.0	0.0	0.0	0.9	3.2
Burford DS	SR-04.14	Replace existing 3 x 3.60MVA 27.6-8.32kV transformers with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6
Calstock DS	SR-04.15	Replace existing 7.50MVA 115.00-25.00kV transformer with 7.50MVA unit	0.0	0.5	4.4	0.0	0.0
Campbellford King DS*	SR-04.16	Replace existing 3.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6
Chatham Harwich DS	SR-04.17	Replace existing 3 x 3.60MVA 27.60-8.32kV transformers with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
Chesterville Brannen DS*	SR-04.18	Replace existing 2.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
Colborne DS #2	SR-04.19	Replace existing 3 x 3.00MVA 44.00-8.32kV transformers with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
Collins Bay DS	SR-04.20	Replace existing 3.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
Crampton DS	SR-04.21	Replace existing 5.00MVA 27.60-8.32kV transformer with 7.50MVA unit	0.0	0.0	0.0	0.6	3.6
Dack DS	SR-04.22	Refurbish existing 3.00MVA 12.47-12.47kV transformer and associated transformers with 5.00MVA unit	0.0	0.5	1.7	4.7	0.0
Decewsville RS	SR-04.23	Refurbish existing 15.00MVA 27.60-27.60kV transformer with 15.00MVA unit	0.0	0.5	1.7	4.7	0.0
Deseronto DS*	SR-04.24	Replace existing 3.00MVA 44.00 - 4.16kV transformer with 5.00MVA unit	1.8	5.0	0.0	0.0	0.0
Devlin DS	SR-04.25	Refurbish existing 3 x 2.00MVA 44.00 - 12.47kV transformers with 5.00MVA unit	0.0	0.5	1.7	4.7	0.0
Duff DS	SR-04.26	Convert existing 5.00MVA 27.60-8.32kV station to PDS with 4 x 2.50MVA units	0.0	0.0	0.0	0.5	2.8
Dundas Sydenham DS	SR-04.27	Replace existing 3.00MVA 27.60-8.32kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6
Elk Lake DS*	SR-04.28	Convert existing 3 x 0.67MVA 44.00-4.16kV transformer and 1.50MVA 4.16-4.16kV transformer to PDS with 2 x 3.00MVA units	3.2	2.5	0.0	0.0	0.0
Elliot Lake DS	SR-04.29	Replace existing 6.70MVA 44.00-12.47kV transformer with 7.50MVA unit	0.0	0.5	3.4	0.0	0.0

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
Elliot Lake Mississauga DS	SR-04.30	Replace existing 6.70MVA 44.00-12.47kV transformer with 7.50MVA unit	0.0	0.5	3.4	0.0	0.0
Elmvale DS	SR-04.31	Replace existing 3.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.6	3.4	0.0	0.0	0.0
Emo DS T1	SR-04.32	Replace existing 3 x 2.67MVA 44-12.47kV transformers with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
Emo DS R1	SR-04.33	Replace existing 2.67MVA 12.47-12.47kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.1	0.9
Exeter DS #2	SR-04.34	Replace existing 2.00MVA 27.60-8.32kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6
Forest Jefferson DS*	SR-04.35	Convert existing 3.60MVA 27.60-4.16kV station to PDS with 2 x 2.50MVA units	0.0	0.0	0.0	0.2	1.4
Forest McNab DS*	SR-04.36	Convert existing 5.60MVA 27.60-4.16kV station to PDS with 2 x 2.50MVA units	0.0	0.3	1.4	0.0	0.0
Glancaster RS	SR-04.37	Replace existing 25.00MVA 27.60-27.60kV transformer with 25.00MVA unit	0.5	1.5	0.0	0.0	0.0
Guelph DS	SR-04.38	Replace existing 5.00MVA 44.00-8.32kV transformer with 7.50MVA unit	0.0	0.5	3.4	0.0	0.0
Guthrie DS	SR-04.39	Replace existing 3 x 3.00MVA 44.00-8.32kV transformers with 5.00MVA unit	0.5	3.5	0.0	0.0	0.0

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
Horsey Bay DS	SR-04.40	Replace existing 5.00MVA 44.00-8.32kV transformer with 7.50MVA unit	0.0	0.0	0.6	3.4	0.0
Huron Park DS	SR-04.41	Replace existing 3.00MVA 27.60-8.32kV transformer with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
Mair Mills DS	SR-04.42	Replace existing 5.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6
Manitouwadge DS #1	SR-04.43	Decommission existing 6.00MVA 12.47-12.47kV transformer and associated transformers and offload to adjacent feeders	0.0	0.3	1.1	0.0	0.0
Matheson DS	SR-04.44	Refurbish existing 3 x 3.60MVA 27.60-12.47kV transformers with 5.00MVA unit	0.0	0.0	0.6	1.7	4.9
Maxville Prince DS*	SR-04.45	Convert existing 2.00MVA 44.00-4.16kV station to PDS with 2 x 3.00MVA units	0.0	0.0	0.0	0.6	2.0
Millington DS	SR-04.46	Refurbish existing 5.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.0	0.5	1.7	4.8	0.0
Moonstone DS	SR-04.47	Replace existing 5.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.5	3.5	0.0	0.0	0.0
Muskoka Falls DS	SR-04.48	Replace existing 6.00MVA 44.00-12.47kV transformer with 7.50MVA unit	0.0	0.0	0.6	3.5	0.0
North Augusta DS #2	SR-04.49	Replace existing 7.50MVA 44.00-	0.0	0.0	0.6	3.5	0.0

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
		8.32kV transformer with 7.50MVA unit					
Oil Springs DS	SR-04.50	Replace existing 3 x 0.90MVA 27.60-8.32kV transformers with 5.00MVA unit	0.5	3.5	0.0	0.0	0.0
Owen Sound 12 St E DS T1*	SR-04.51	Replace existing T1 5.00MVA 44.00-4.16kV transformer with 7.50MVA unit	0.0	0.0	0.0	0.6	3.6
Owen Sound 12 St E DS T2*	SR-04.52	Replace existing T2 5.00MVA 44.00-4.16kV transformer with 7.50MVA unit	0.0	0.0	0.6	3.5	0.0
Owen Sound DS #2	SR-04.53	Convert existing 3 x 2.00MVA 44.00-8.32kV station to PDS with 2 x 3.00MVA units	0.5	2.0	0.0	0.0	0.0
Pelee Island GS	SR-04.54	Replace both fuel tanks with like-for-like equivalents	0.0	3.5	0.0	0.0	0.0
Peterborough Erskine DS*	SR-04.55	Convert existing 2 x 3.00MVA 44.00-4.16kV station to PDS with 2 x 3.00MVA units	0.0	0.0	0.0	0.6	2.0
Port Elgin DS	SR-04.56	Refurbish existing 3.00MVA 44.00-8.32kV transformer with 7.50MVA unit	0.0	0.0	0.6	1.7	4.9
Port Dover St. Andrews DS	SR-04.57	Replace existing 5.00MVA 27.60-8.32kV transformer with 7.50MVA unit	0.0	0.0	0.6	3.5	0.0
Reid Corners DS	SR-04.58	Replace existing 3.00MVA 44.00-8.32kV transformer with 7.50MVA unit	0.0	0.5	3.4	0.0	0.0
Rugby DS	SR-04.59	Replace existing 3.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
Sebright DS	SR-04.60	Replace existing 3.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6
Shelburne Andrew DS*	SR-04.61	Convert existing 5.00MVA 44.00-4.16kV station to PDS with 2 x 3.00MVA units	0.0	0.0	0.6	2.0	0.0
Shelburne DS*	SR-04.62	Replace existing 3.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.5	3.5	0.0	0.0	0.0
Simcoe Ireland DS	SR-04.63	Replace existing 5.00MVA 27.60-8.32kV transformer with 7.50MVA unit	0.0	0.0	0.0	0.6	3.6
Sleeman DS	SR-04.64	Refurbish existing 3 x 3.00MVA 44.00-12.47kV transformers with 5.00MVA unit	0.0	0.0	0.6	1.7	4.9
Smiths Falls James DS*	SR-04.65	Replace existing 5.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
Snow Road DS	SR-04.66	Replace existing 3.00MVA 44.00-12.47kV transformer with 5.00MVA unit	0.5	3.4	0.0	0.0	0.0
Straffordville DS	SR-04.67	Replace existing 5.00MVA 27.60-8.32kV transformer with 7.50MVA unit	0.0	0.5	3.4	0.0	0.0
Sturgeon Falls DS	SR-04.68	Replace existing 6.00MVA 44.00-12.47kV transformer with 10.00MVA unit	0.0	0.0	0.6	3.5	0.0
Sundridge DS	SR-04.69	Replace existing 3.00MVA 44.00-12.47kV transformer with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
Thorold Allanport DS*	SR-04.70	Convert existing 5.40MVA 27.60-	0.0	0.0	0.0	0.2	1.4

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
		4.16kV station to PDS with 2 x 2.50MVA units					
Thorold Front DS*	SR-04.71	Convert existing 5.40MVA 13.8-4.16kV station to PDS with 2 x 2.50MVA units	0.0	0.0	0.0	0.2	1.4
Thorold Ormond DS*	SR-04.72	Convert existing 5.00MVA 13.8-4.16kV station to PDS with 2 x 2.50MVA units	0.0	0.0	0.0	0.2	1.4
Thorold Turner DS	SR-04.73	Convert existing 3 x 3.60MVA 27.60-8.32kV station to PDS with 2 x 2.50MVA units	0.2	1.3	0.0	0.0	0.0
Trenton Dixon DS*	SR-04.74	Convert existing 5.00MVA 44.00-4.16kV station to PDS with 2 x 3.00MVA units	0.0	0.0	0.6	2.0	0.0
Trenton McAuley DS*	SR-04.75	Replace existing 3.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.0	0.5	3.4	0.0	0.0
Vandeleur DS	SR-04.76	Replace existing 3.00MVA 44.00-8.32kV transformer with 5.00MVA unit	0.5	3.4	0.0	0.0	0.0
Virginiatown DS*	SR-04.77	Replace existing 3 x 2.00MVA 44.00-4.16kV transformers with 5.00MVA unit	0.0	0.0	0.0	0.6	3.6
Washago DS	SR-04.78	Replace existing 5.00MVA 44.00-8.32kV transformer with 7.50MVA unit	0.0	0.5	3.4	0.0	0.0
White River DS	SR-04.79	Replace existing 7.50MVA 115.00-25.00kV transformer with 7.50MVA unit	0.0	0.0	0.0	0.6	4.6

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
Woodland Beach DS	SR-04.80	Replace existing 5.00MVA 44.00-8.32kV transformer with 10.00MVA unit	0.0	0.0	0.6	3.5	0.0
Young JCT RS	SR-04.81	Replace existing 15.00MVA 27.60-27.60kV transformer with 15.00MVA unit	0.0	0.5	3.4	0.0	0.0
Total			**10.4**	**55.2**	**101.7**	**72.3**	**89.5**

**Transformers identified under DSP Section 3.11, D-SR-17 as voltage consolidation candidates*

APPENDIX B - DESCRIPTION OF ORILLIA INVESTMENTS

There are no planned Orillia investments in the 2028-2032 rate period.

APPENDIX C - DESCRIPTION OF PETERBOROUGH INVESTMENTS

			Net Capital Investment ($M)				
Project Name	**Project ID**	**Project Description**	**2028**	**2029**	**2030**	**2031**	**2032**
Peterborough Aylmer DS	SR-04.82	Convert existing T1, T2, T3 each 3.00MVA 44.00-4.16kV station to PDS with 4 x 3.00MVA units	0.00	0.68	2.44		
Peterborough Simcoe DS	SR-04.83	Convert existing 2 x 3.00MVA 44.00-4.16kV station to PDS with 2 x 3.00MVA unit	0.75	0.00	0.00		
Peterborough Wallis DS	SR-04.84	Refurbish existing 5.00MVA 44.00-4.16kV transformer with 5.00MVA unit	0.33	1.02	2.99		
Total			**1.08**	**1.70**	**5.43**		

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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

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	188.8	192.6	196.4	200.8	204.8	983.4
Orillia RZ	0.17	0.17	0.17	Embedded in Hydro One Networks		
Peterborough RZ	0.32	0.33	0.34			

Summary:

This investment supports Hydro One's response to unplanned events including asset failure, storm damage, third-party damage, service interruptions, and immediate safety hazards. The work is non-discretionary and is required to support timely restoration, maintain public safety and support the reliable operation of the distribution system.

1.0 INVESTMENT NEED

This is a demand-driven program that provides 24-hour, seven-day-a-week response and restoration activities required following unplanned interruptions or other system deficiencies. The program supports activities required to restore service, address failed or damaged assets, mitigate immediate safety hazards, and complete permanent restoration where temporary repairs are initially required to restore service safely. It also supports Hydro One's compliance with sections 4.5, Unplanned outages and Emergency Conditions, and 7.9, Emergency Response, of the Distribution System Code (DSC).

Trouble Call and Storm Damage Response work is required when Hydro One must respond to an unplanned or immediate system need, such as:

- Equipment damage or asset failure during severe weather;
- Equipment damage due to foreign interference events causing replacement of assets (i.e.: motor vehicle accidents, dig-ins);
- Damaged or failed assets identified through patrols and inspections or customer reports that present an immediate safety hazard; and
- Permanent restoration required after temporary repairs.

As discussed in DSP Section 3.1, Hydro One's distribution system has a unique physical and operating context. Hydro One serves 1.5 million customers across a service territory that covers 75% of Ontario's geographic area. The service area is 99.9% rural. The distribution system consists of approximately 126,000 circuit-km of lines, of which approximately 91% are overhead, supported by 1.6 million Hydro One owned poles. Hydro One's distribution facilities extend across southern, central, eastern, and northern Ontario, including dense urban communities, rural road allowances, off-road locations, forested and agricultural areas, islands, and remote locations.

This system context materially affects the need for this program. Hydro One's predominantly overhead system extends across a large and geographically dispersed service territory and is exposed to various severe weather conditions, including high winds, blizzards, ice storms, and lightning. These events can result in widespread damage or cascading failures, including pole failures, downed conductors, damaged transformers,

failed protective equipment, and access constraints. Restoration can require long-distance travel, difficult road and off-road access, specialized vehicles and equipment, material staging, contractor support, and coordination of crews and mutual assistance across multiple operating areas.

To illustrate, Figure 1 below provides various photos of severe weather damage to distribution line assets. More specifically, 1D and 1E illustrate when storm conditions cause pole failures that trigger cascading outages, resulting in the failure of a larger number of distribution assets.

A.



B.



C.



D.



E.



Figure 1: Examples of Storm Damage

Recent experience demonstrates an increase in both the frequency and severity of storms. As shown in Table 1, Hydro One has experienced multiple severe weather events in recent years, including wind storms, the May 2022 derecho, the December 2022 winter storm, the April 2023 freezing rain event, and the March 2025 ice storm. These events resulted in significant customer interruptions, customer-hours of interruption, restoration activity, and capital costs.

The May 2022 derecho and the March 2025 ice storm were particularly severe, together resulting in approximately 73 million customer-hours of interruption and net expenditures of approximately $306M. The March 2025 ice storm alone resulted in approximately 1.22 million customer interruptions, produced approximately 49 million customer-hours of interruption, and resulted in 32.7 hours of SAIDI.

Table 1 - Comparison of Recent Historical Major Events[1]

Date	Nov 2020	Dec 2021	May 2022	Dec 2022	April 2023	March 2025
Type of Event	**Wind Storm**	**Wind Storm**	**Derecho**	**Winter Storm**	**Freezing Rain**	**Ice Storm**
Customer Interruptions (in 1000s)	572	761	890	525	359	1,220
Customer Hours of Interruption (in 1000s)	7,043	8,908	24,141	5,701	5,966	49,008
SAIFI	0.4	0.5	0.6	0.4	0.2	0.8
SAIDI	5.0	6.2	17.0	3.8	4.1	32.7
Net Costs ($M)[2]	$24.4	$25.6	$109.3	$45.5	$29.9	$196.2

[1] Table as per the EB-2025-0030 – Hydro One Networks Inc. – Application for 2026 Distribution Revenue Requirement.
[2] Net costs are inclusive of all distribution rate zones.

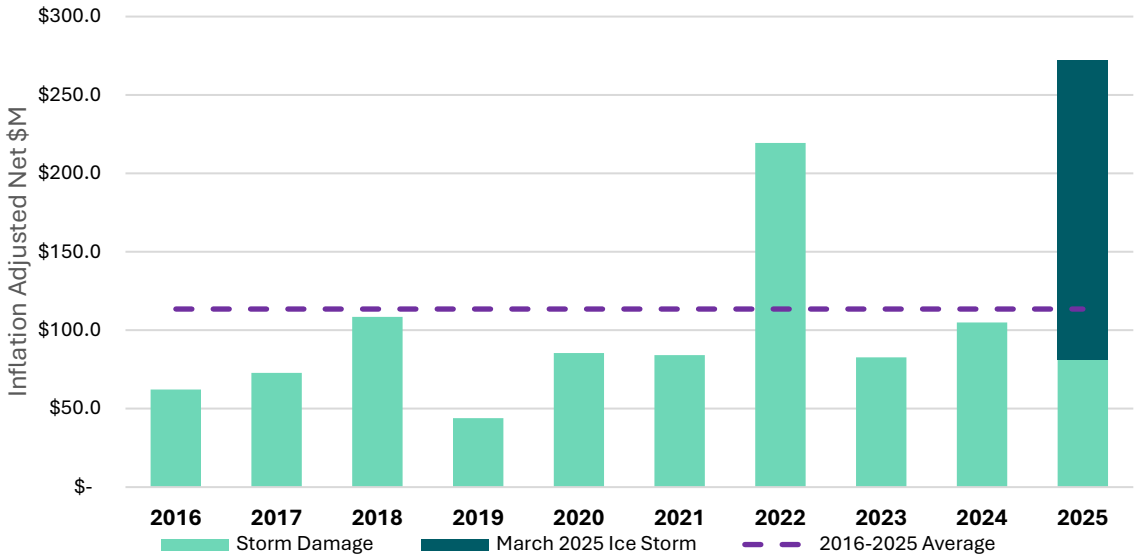


Figure 2: Hydro One Storm 2016-2025 Net Expenditures (adjusted to inflation)

As shown in Figure 3 below, Hydro One Distribution has experienced a sustained increase in the number of Force Majeure (FM) and storm days. Recently, the recent five-year average (2020-2024) has been 51.6 days, which is greater than the 10-year average (2015-2024) of 48.4 days. In 2025, there were 62 FM and storm days, which represents an increase of 28% over the 10-year average.

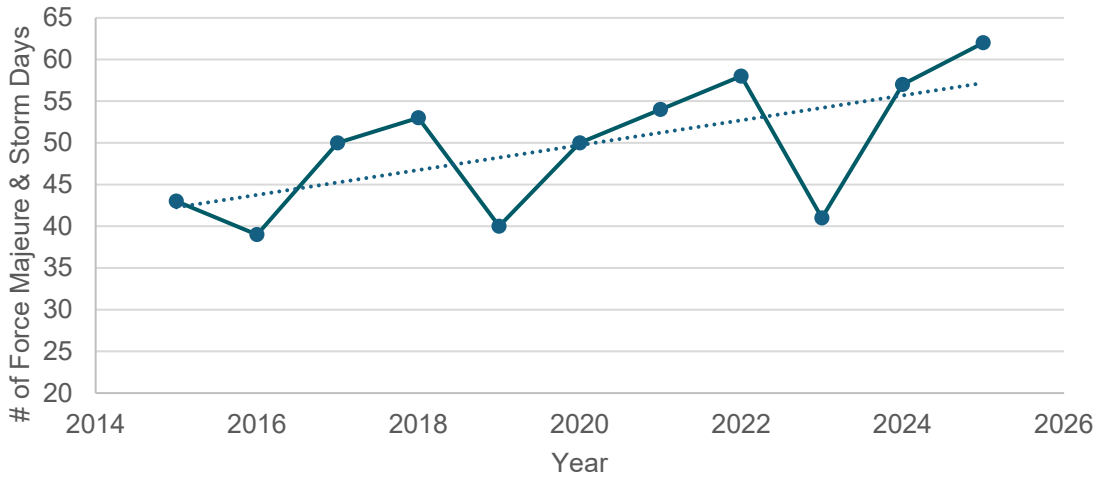


Figure 3: 2015-2025 Count of FM and Storm Days

Hydro One's evidence supports the continued need for a base level of capital funding for trouble call and storm damage response. Although the exact timing, location, and severity of future events cannot be predicted, Hydro One's own recent experience demonstrates that wind, derecho, winter storm, freezing rain, and ice storm events are recurring drivers of material restoration work on the distribution system.

Hydro One's 2026 Vulnerability Assessment and System Hardening (VASH) analysis, filed as part of DSP Section 3.3, subsection 3.3.2.5, provides Hydro One-specific forward-looking evidence on climate change. As per Figure 4 below, the VASH analysis shows increasing vulnerability for subtransmission and distribution feeders particularly in Hydro One's North and East regions. In the near-North, the increase is driven primarily by projected increases in ice accretion severity from freezing rain events and the interaction of that hazard with vegetation around overhead assets. In the East region, feeders show high relative climate vulnerability due to projected increased exposure to both severe wind and ice accretion conditions, combined with vegetation exposure around overhead infrastructure. In the Central region, the more vulnerable feeders are generally clustered along the north-eastern shores of Lake Ontario, where projected exposure to both ice accretion caused by freezing rain and high wind speeds contributes to higher relative vulnerability. The South region is comparatively less vulnerable than other regions in the VASH results.

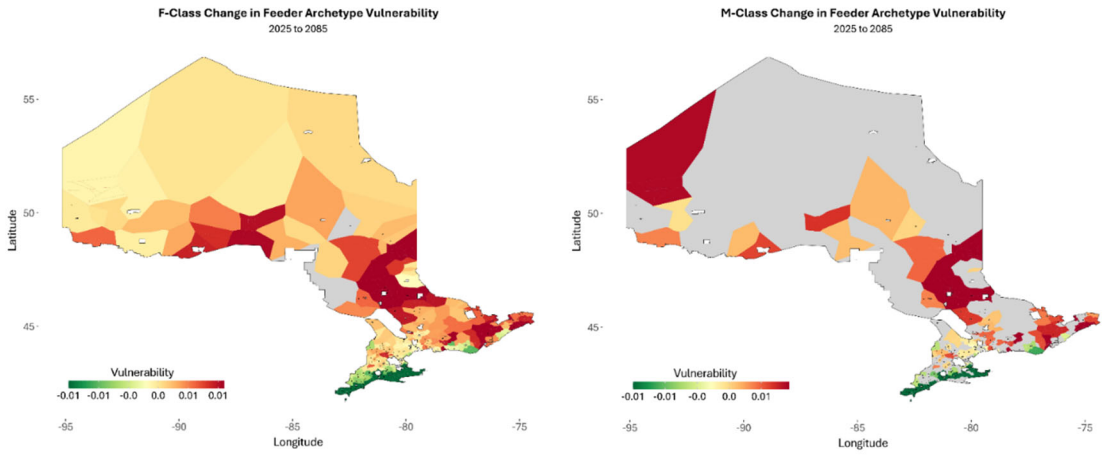


Figure 4: Change in vulnerability of subtransmission (M-class) and distribution (F-class) feeder groups from 2025 to 2085.

Overall, the VASH analysis supports the conclusion that Hydro One's storm and trouble response requirements will remain material over the 2028-2032 period. The analysis provides forward-looking evidence that the climate hazards affecting Hydro One's overhead distribution system will continue and increase in relative vulnerability. This supports the continued need for base funding for storm and trouble response.

2.0 INVESTMENT DESCRIPTION

This 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. The 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 for failed assets or those that pose an immediate safety hazard.
- Emergency submarine and underground cable replacements for failed assets or hazardous conditions where a significant section of the neutral cross section is missing or broken.
- Storm damage response to resolve service interruptions caused by adverse weather conditions. This sub-program covers all capital costs for the replacement

of failed assets (e.g., poles, conductors, transformers, reclosers, regulators and switches) and the execution of storm response as detailed in DSP Section 3.10, Subsection 3.10.2.

- 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 restoration and recovery. Key work activities most commonly include pole replacement from motor vehicle accidents and conductor replacement from dig-ins or accidental contact.

Figure 5 illustrates the actual expenditures from 2023-2025 and the forecast program expenditures over the 2026 to 2032 period. The program expenditures vary from year to year due to the unpredictable nature of emergency work, particularly storm restoration activities. The most significant increases occurred in 2025 due to the March ice storm. Despite the variability, the overall expenditure trend reflects increasing restoration demands.

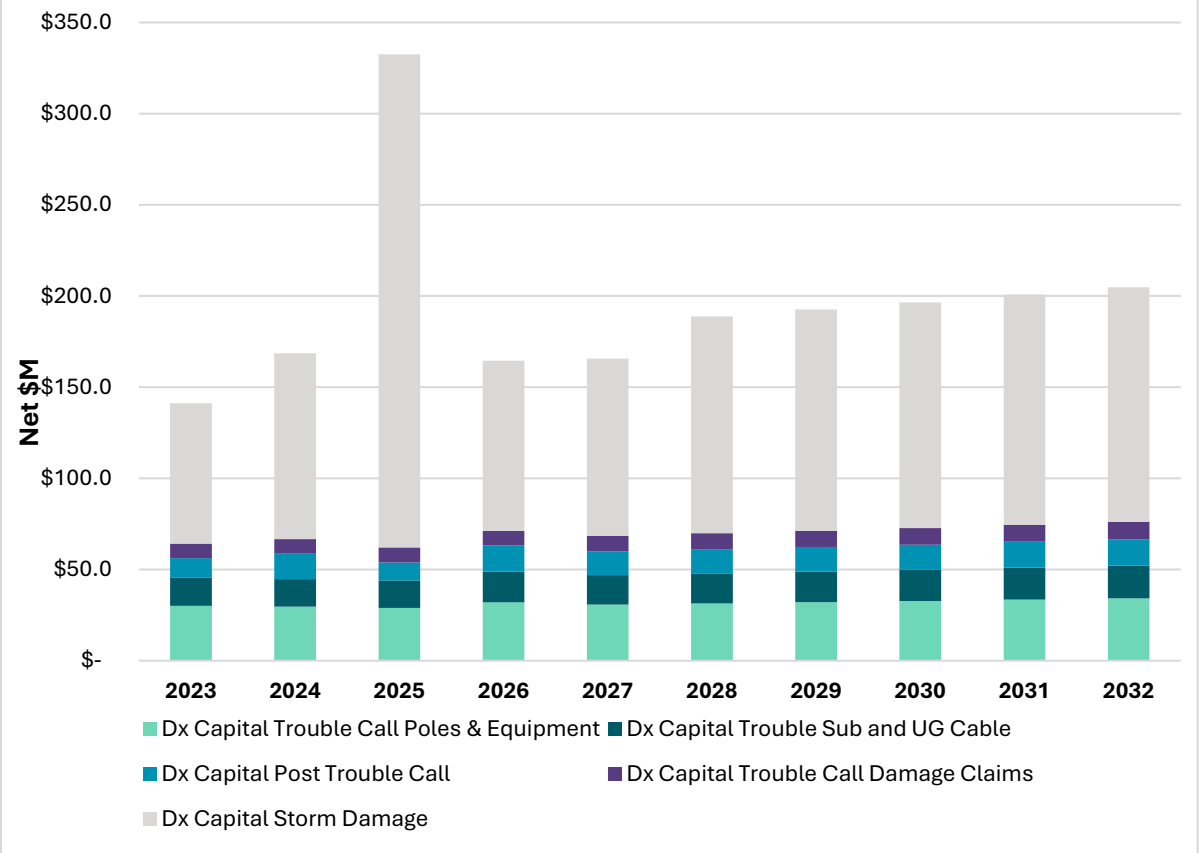


Figure 5: Trouble Call and Storm Response Expenditures (2023-2032)

3.0 OUTCOMES

The Trouble Call and Storm Damage Response program is necessary to:

- Ensure Hydro One Distribution's ability to respond to trouble calls and service interruptions.
- Mitigate reliability and safety risks during and after emergency events.
- Comply with regulatory requirements with respect to timely incident response and restoration of supply.

3.1 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	• 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

4.0 EXPENDITURE PLAN

Tables 3, 4, and 5 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 rate period.

Table 3 - Hydro One - Investment Expenditures[3]

($M)	Plan[4] 23-27	Act/Fcst[5] 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	655.4	1,155.4	226.0	230.5	235.1	240.5	245.3	1,177.3
Less Removals	74.8	131.4	25.7	26.2	26.7	27.4	27.9	133.9
Less Capital Contributions	0.0	51.6	11.5	11.7	12.0	12.3	12.5	60.0
Net Capital Expenditures	**580.6**	**972.3**	**188.8**	**192.6**	**196.4**	**200.8**	**204.8**	**983.4**

Table 4 - Orillia - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	-	2.97	0.24	0.25	0.25	Embedded in Hydro One Networks		
Less Removals		0.41	0.04	0.04	0.04			
Less Capital Contributions		0.09	0.04	0.04	0.04			
Net Capital Expenditures		**2.47**	**0.17**	**0.17**	**0.17**			

[3] Figures presented in the tables may not sum to the totals shown due to rounding
[4] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[5] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Table 5 - Peterborough - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	-	9.64	0.45	0.46	0.47	Embedded in Hydro One Networks		
Less Removals		1.33	0.07	0.07	0.07			
Less Capital Contributions		0.45	0.06	0.06	0.06			
Net Capital Expenditures		**7.87**	**0.32**	**0.33**	**0.34**			

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.

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditure for this investment to be $391.7M higher than planned. This is primarily driven by a higher volume of storm damage response, trouble sub cable and underground replacements, and damage claims. Storm damage increased from $290.9M to $641.1M, a $350.2M increase, primarily due to the March 2025 ice storm which generated approximately $196.2M in expenditures, making it the most costly and disruptive weather event Hydro One has experienced in recent history. The event resulted in approximately 1.22 million customer interruptions and over 600,000 impacted customers, far exceeding previous major storms. The costs were primarily driven by the scale of the infrastructure damage, extensive emergency restoration efforts, significant replacement of damaged assets, high labour hours and contractor utilization, and the time required to complete restoration activities. The volume of trouble sub-cable and underground replacements is due to the increased volume of emergent cables and demand-driven third-party requests.

In addition to increased volume, expenditures are impacted by significant market-wide cost escalation affecting materials required to deliver this work. Since 2020, Distribution transformer prices (for units less than 2.5 MVA) have increased by 40% on average, conductor, cables and wires increased by 65% on average, and distribution poles

increased by 45% on average, as presented in SPF Section 1.8, Table 1. These materials are key inputs to Trouble Call and Storm Damage Response activities and have contributed to the increase in the cost of delivering work.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, the forecast expenditures are planned to be $983.4M, which is generally consistent with the 2023-2027 actual and forecast expenditure level, as seen in Table 6. The forecast expenditures for this program are projected at the program level to reflect the different demand characteristics of storm and non-storm work. The resulting forecast reflects both recent demand trends and the continued need to maintain emergency response capability across Hydro One's service territory.

Table 6 - Hydro One – Expenditure Continuity Over Rate Periods[6]

($M)	Plan 23-27	Forecast 23-27	Total 28-32
Trouble Call Poles & Equipment	134.1	150.8	163.8
Storm Damage	290.9	641.1	618.9
Trouble Sub and UG Cable	44.7	78.2	85.8
Post Trouble Call	94.7	61.7	69.4
Trouble Call Damage Claims	16.2	40.6	45.5
Total	**580.6**	**972.3**	**983.4**

Storm damage expenditures are forecast using a ten-year inflation-adjusted historical average as shown in Figure 2, including the March 2025 ice storm. This forecasting period is used because of the unpredictable nature of storms such as severity, frequency, geographic extent and resulting degree of damage. The longer planning horizon averages the variability while remaining responsive to more recent operating experience. The inclusion of high impact severe weather events is consistent with the Z-Factor decision in (EB-2025-0030). As a result, Hydro One has established an appropriate level of funding to manage storm restoration requirements during the rate period.

[6] Figures presented in the tables may not sum to the totals shown due to rounding.

Expenditures for remaining activities are guided by an inflation adjusted two-year historical average. The shorter planning period reflects the more recent level of activity experienced within these programs.

While increasing investment in planned pole replacement, underground cable renewal, vegetation management and other resilience initiatives, these programs are not expected to eliminate the need for emergency restoration work. A significant portion of Trouble Call and Storm Damage Response expenditures are driven by external events such as severe weather, motor vehicle accidents, and other third-party damage that occur independently of asset condition. In addition, emergency work may involve assets that are outside of Hydro One's near-term replacement plans. Accordingly, the forecast is based on historical demand and recent storm experiences.

5.0 ALTERNATIVES

No alternative funding levels were considered for non-storm programs, as timely response to service interruptions, failed assets, and safety hazards is required to meet Hydro One's service obligations under the Distribution System Code and would result in unacceptable reliability and safety risks.

Alternative funding scenarios were considered only for storm restoration during the business planning process.

ALTERNATIVE 1: TEN-YEAR FORECAST EXCLUDING MARCH 2025 ICE STORM

Under this alternative, storm restoration expenditures would be forecast using recent storm experience while excluding the March 2025 ice storm. This approach recognizes that recent years have experienced a higher level of storm activity than the long-term historical average and therefore provides a higher funding level than the twenty-year forecast alternative. Excluding the March 2025 ice storm reduces the impact of an unusually severe event that may be considered an outlier. However, given the trend toward more frequent and intense weather-related events, excluding the March 2025 storm may not fully capture the restoration resources required to respond to future severe weather. Consequently, this alternative may underestimate future storm response

requirements and could increase the risk of funding shortfalls during significant storm events.

ALTERNATIVE 2: TEN-YEAR FORECAST INCLUDING HIGH IMPACT STORMS (RECOMMENDED)

Under this alternative, storm restoration expenditures would be forecast using recent storm experience, including the March 2025 ice storm. March 2025 was a particularly severe storm event that resulted in substantial damage to the distribution system and required significant restoration resources to safely restore service to customers. Including this event in the forecast recognizes the potential for major weather-related disruptions and better reflects the operating environment Hydro One is increasingly experiencing. This approach provides the highest degree of preparedness for future storm response activities, reducing the risk of funding deficiencies and supporting timely restoration efforts following major events. While this alternative results in higher forecast expenditures, it is considered prudent approach to forecasting current and emerging storm risk and would best allow planned work programs to not be reduced to fund storm program cost exceedances.

6.0 EXECUTION RISK AND MITIGATION

Hydro One successfully restores power to hundreds of thousands of customers each year and does not anticipate any major risks to this program under normal operating conditions. However, large-scale weather events may result in widespread damage and restoration requirements that exceed available resources. In these circumstances, restoration work is prioritized to maximize customer restoration while maintaining a strong focus on safety and operational efficiency. Restoration activities may also be constrained by crew safety and fatigue considerations, as well as limited availability of mutual assistance resources through Ontario Mutual Assistance Group (OnMAG) and North Atlantic Mutual Assistance Group (NAMAG) when participating utilities are responding to storm impacts within their own service territories. These risks are actively managed through established emergency response protocols, resource planning, and mutual assistance agreements, and are not expected to materially impact Hydro One's ability to restore service following storm events.

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D-SR-07	POLE SUSTAINMENT PROGRAM
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	54.3	169.1	187.0	242.0	266.9	919.3
Orillia RZ	0.02	0.02	0.02	Embedded in Hydro One Networks		
Peterborough RZ	2.42	2.47	2.52			

Summary:

The Pole Sustainment Program reflects Hydro One's lifecycle approach for managing the condition, reliability, and long-term risk of its distribution pole fleet. The program is designed to address both the existing population of poor condition poles and the ongoing deterioration of the broader pole population through a coordinated set of lifecycle interventions. The proposed investment will sustainably manage the risks associated with a growing population of deteriorating poles and increasing exposure to severe weather events that can accelerate deterioration and amplify its consequences. This investment comprises four coordinated activities, Test and Treat, Pole Refurbishment, Individual Pole Replacement, and Clustered Hardening, which proactively identify deteriorated poles, extend pole life where safe and cost-effective to do so, replace dispersed end-of-life poles, and address concentrations of poor condition poles in areas with elevated reliability and resilience risks. Investments in this program are prioritized based on customer impact and risk, supporting a coordinated asset management approach that manages deterioration throughout the pole lifecycle, strengthens system resilience, and maintains the long-term health, reliability, and performance of Hydro One's pole fleet.

1.0 INVESTMENT NEED

Hydro One owns and maintains approximately 1.6 million distribution poles, which support conductors, transformers, switches, protection devices, and other overhead distribution assets. Pole failures can result in public safety concerns, customer interruptions, emergency restoration costs, damage to adjacent equipment, and increased impacts during severe weather events. Effective management of pole condition is therefore critical to maintaining safe and reliable distribution service.

Historically, Hydro One has primarily managed poor condition poles through targeted replacement and refurbishment of individual assets prioritized according to risk and customer consequences. This approach remains appropriate where poor condition poles are geographically dispersed and continues to form a core component of the program.

At the same time, the scale and pattern of pole deterioration are changing as the fleet ages. Inspection results show that the number of poor condition poles identified annually has increased approximately 50%, from 10,000 in 2021 to approximately 15,000 annually based on 2023-2025 inspection results. Pole-caused customer interruptions have increased by approximately 58% between 2020 and 2025, excluding Force Majeure events, with each pole-caused forced outage resulting in an average 9.8-hour interruption. These trends demonstrate a growing condition-related reliability risk that requires a higher level of planned sustainment activity.

Inspection results have also identified localized clusters of deterioration among poles with similar service lives, construction characteristics, and environmental exposure. The emergence of these concentrated poor condition poles reflects the aging profile of the fleet and its increasing vulnerabilities to severe weather. Where poor condition poles are geographically dispersed, individual refurbishment or replacement remains appropriate. Where deterioration is concentrated in clusters, coordinated renewal provides a more effective approach to addressing the broader area-level condition need and reducing repeated planning, mobilization, outage coordination, and construction activity over time.

The need for the Pole Sustainment Program is driven by three primary factors:

- **A large and aging pole population**, with an increasing number of poles reaching or exceeding expected service life;
- **A growing population of poor condition poles**, with additional poles continuing to deteriorate into poor condition each year; and
- I**ncreasing exposure to severe weather events**, which can amplify the reliability, safety and customer impacts associated with deteriorated pole assets.

The proposed program therefore builds on Hydro One's existing asset management approach by combining testing, refurbishment, targeted replacement, and a new clustered approach that replaces geographically concentrated groups of poor condition poles.

The program's objective is to manage the long-term condition and risk of the pole fleet by addressing poor condition poles and the continuing deterioration of the broader fleet. Hydro One will prioritize the highest-risk condition needs and materially limit growth in the poor condition pole population during the planning period. Specifically, Hydro One will proactively identify deterioration, extend pole life where technically feasible and cost-effective, prioritize replacement of poor condition poles with greater customer and reliability consequences, and address concentrations of deteriorated poles where coordinated renewal in clusters provides a more effective intervention.

Accordingly, the Pole Sustainment Program consists of four coordinated investment activities:

- **Test and Treat** – Identifies poles that require replacement or mechanical refurbishment and chemically treats poles at the ground line to manage deterioration and extend service life;
- **Pole Refurbishment** – Restores mechanical strength by adding structural support to poor condition poles that meet the criteria for refurbishment;
- **Pole Replacement** – Replaces individual poles in poor condition that cannot be refurbished and are geographically dispersed;
- **Clustered Hardening** – Replaces concentrations of poor condition poles within common feeder sections. In locations vulnerable to severe weather, stronger poles are installed to improve system resilience.

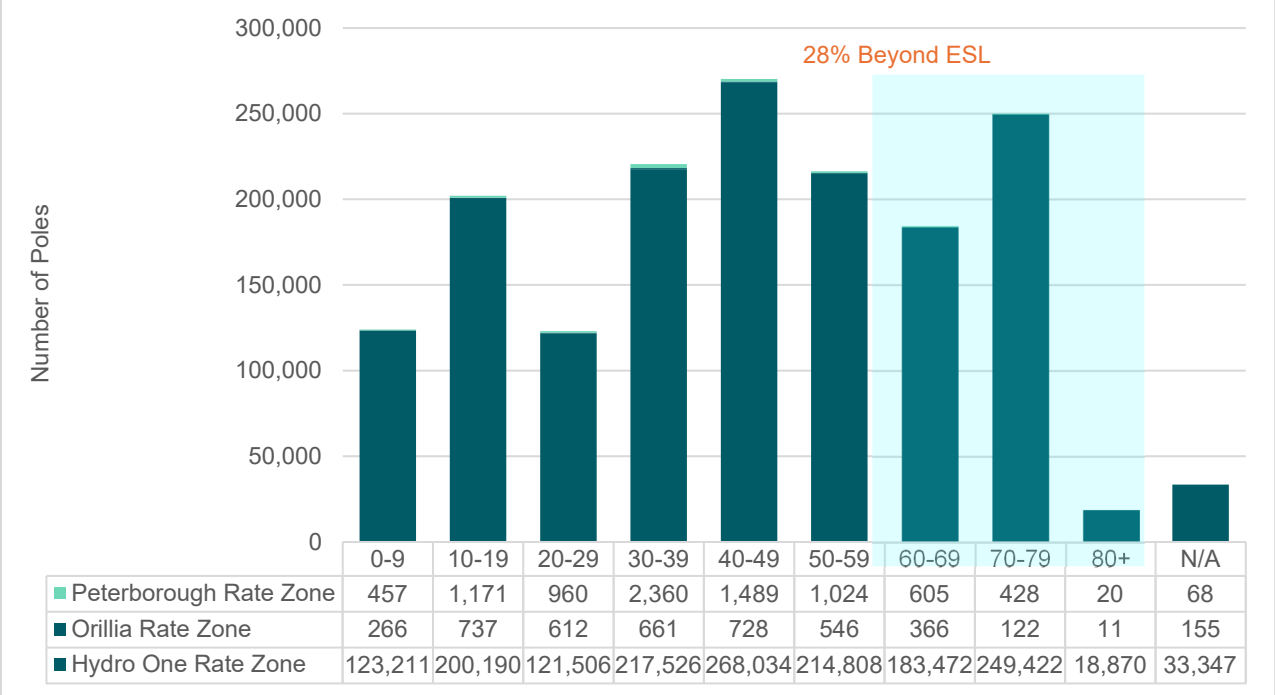
Together, these activities allow Hydro One to apply the appropriate intervention at different stages of the pole lifecycle while directing full replacement toward assets and locations where it is required.

Hydro One coordinates the Pole Sustainment Program with other programs that may also involve pole replacement to ensure investments are planned and executed efficiently and to avoid duplication of work. However, pole replacements completed through Distribution Lines Trouble and Storm Damage Response Program (D-SR-05), Distribution Lines Sustainment Initiatives (D-SR-10), and Selective Undergrounding Program (D-SR-14) are tracked and reported separately and are not included in the volumes or outcomes presented for the Pole Sustainment Program.

1.1 POLE FLEET DEMOGRAPHICS

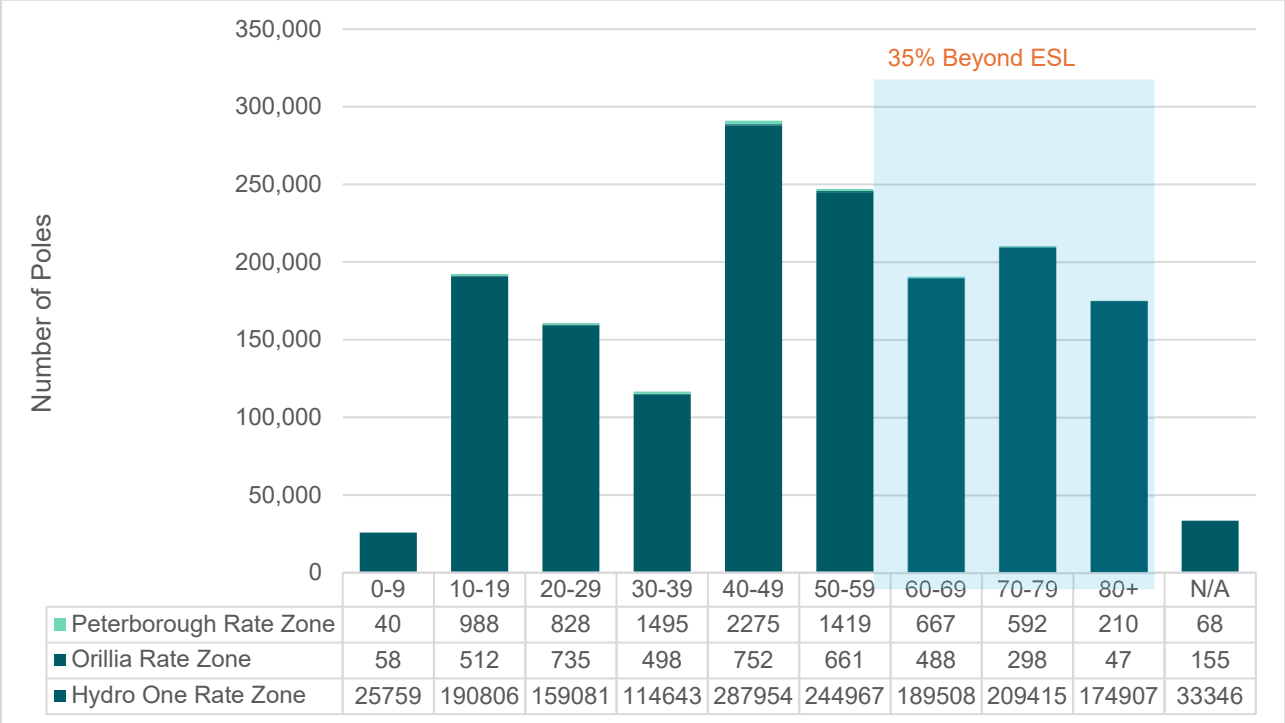
Hydro One owns approximately 1.6 million distribution poles across its service territory, approximately 99% of which are wood poles. The expected service life of a distribution pole on Hydro One’s system is approximately 60 years, and the average pole has been in service for approximately 44 years, as the fleet continues to age.

Figure 1, below, shows that more than 450,000 poles, representing 28% of the fleet, have currently been in service for 60 years or longer. Without investment, this population is forecast to grow to approximately 576,000 poles by 2032, representing 35% of the fleet, as shown in Figure 2. This demographic trend indicates the increasing proportion of the fleet entering service life ranges in which deterioration is more prevalent and provides a key forward-looking indicator of the scale of future sustainment requirements. The aging profile increases Hydro One's long-term exposure to condition-related risks and underscores the need for continued sustainment activities to identify, refurbish, and replace deteriorated poles before failures occur.



	0-9	10-19	20-29	30-39	40-49	50-59	60-69	70-79	80+	N/A
Peterborough Rate Zone	457	1,171	960	2,360	1,489	1,024	605	428	20	68
Orillia Rate Zone	266	737	612	661	728	546	366	122	11	155
Hydro One Rate Zone	123,211	200,190	121,506	217,526	268,034	214,808	183,472	249,422	18,870	33,347

Figure 1: Current Demographics of Hydro One Owned Distribution Poles



	0-9	10-19	20-29	30-39	40-49	50-59	60-69	70-79	80+	N/A
Peterborough Rate Zone	40	988	828	1495	2275	1419	667	592	210	68
Orillia Rate Zone	58	512	735	498	752	661	488	298	47	155
Hydro One Rate Zone	25759	190806	159081	114643	287954	244967	189508	209415	174907	33346

Figure 2: 2032 Forecasted Demographics of Distribution Poles Without Intervention

Witness: Paul Ankrett; Gianni DiFilippo

As shown in Table 1, by 2032 an additional 122,000 poles are forecast to exceed 60 years of service life and approximately 156,000 poles are forecast to exceed 80 years of service. As the pole fleet continues to age, deterioration rates are expected to increase, driving growth in the population of poor condition poles. This growth is increasingly concentrated among the oldest segments of the fleet, where inspection data indicates the highest likelihood of poor condition. Without sustained investment, additions to the poor condition population are expected to accelerate throughout and beyond the 2028-2032 period, posing increasing safety, reliability, and environmental risks. The need for this program thus reflects Hydro One's near- and long-term asset management requirements to mitigate the increasing safety and reliability risks associated with an aging and deteriorating pole fleet.

Table 1 - Comparison of Poles with Operational Life Beyond 60 and 80 Years

	Current, 2025	% of Total Population	By the end of planning period, 2032	% of Total Population	Change, poles
60+	453,316	28%	576,132	**35%**	**+ 122,816**
80+	18,901	1%	175,164	**11%**	**+ 156,263**

1.2 POLE INSPECTIONS

Pole inspections are conducted in accordance with Appendix C of the Distribution System Code, which mandates inspection intervals of six years in rural areas and three years in urban areas. These inspections are carried out as part of the Distribution Lines Patrol program (see Exhibit E-03-02 Subsection 2.2.4) and are primarily intended to identify observable deficiencies on the pole, including woodpecker holes, mechanical surface damage, surface rot, severe leaning, broken poles, or other potential safety issues requiring immediate attention. Identified line defects, including damaged cross arms, insulator defects, and missing guys, are also recorded during these inspections.

As an example, Figure 3 below shows three types of pole-related defects (from left to right): a woodpecker nesting hole, ground-line rot, and pole damage. In all three examples, a significant amount of cross-sectional material has been lost or damaged, creating structural weak points that increase the likelihood of asset failure.



Figure 3: Examples of Poor Condition Poles

In addition to visual inspections, Hydro One collects supplemental condition data through its Test and Treat program, carried out on a 15-year cycle. This program assesses pole condition and chemically treats poles at the ground line to manage deterioration and extend their life. Detailed information collected through this program includes pole dimensions, the extent of any surface damage, and internal condition data obtained through drilling to assess the severity of internal rot. These measurements are used to calculate the remaining strength of the pole, expressed as a percentage of its original design strength. This information, along with visual inspection results, helps identify poles suitable for mechanical refurbishment, enabling Hydro One to select the most prudent intervention to manage condition-related risk and maintain system reliability.

As the pole fleet continues to age and the deterioration process accelerates, inspection results are increasingly identifying localized areas where multiple neighboring poles have deteriorated to poor condition within a similar timeframe. These concentrations can occur where poles share common characteristics within the same feeder sections, such as service life, environmental exposure, and loading profile. Environmental factors, such as soil conditions, moisture exposure, vegetation, and weather patterns, can also contribute to similar deterioration patterns within specific geographic areas. Furthermore, poles within a common feeder section were typically constructed at the same time using similar materials, standards, and installation methods. Together, these common characteristics can result in concentrated areas of deterioration as poles reach similar stages of their lifecycle. For the purpose of this investment, Hydro One refers to these localized concentrations of deteriorated poles as “clusters”.

The emergence of these clusters is relevant to the selection of the appropriate lifecycle intervention. Where poor condition poles remain geographically dispersed, individual refurbishment or replacement continues to be an appropriate and effective approach. Where deterioration is concentrated within a cluster, however, addressing poles individually over time may leave a continuing area-level condition need and require repeated planning, mobilization, outage coordination, and construction activity. Coordinated replacement can address the concentrated condition need more efficiently. Where clusters are located in areas vulnerable to severe weather, coordinated replacement also provides an opportunity to install higher-strength poles and improve the resilience of the renewed feeder section.

Figure 4 illustrates these emerging condition patterns. Poor condition poles continue to occur in individual or dispersed assets, while inspection results also identify that a substantial portion of poor condition poles are located in clusters containing multiple poles, including clusters of ten or more. These results demonstrate that deterioration is increasingly concentrated within localized areas of the system, creating opportunities to address condition needs through coordinated renewal activities rather than repeated individual interventions.

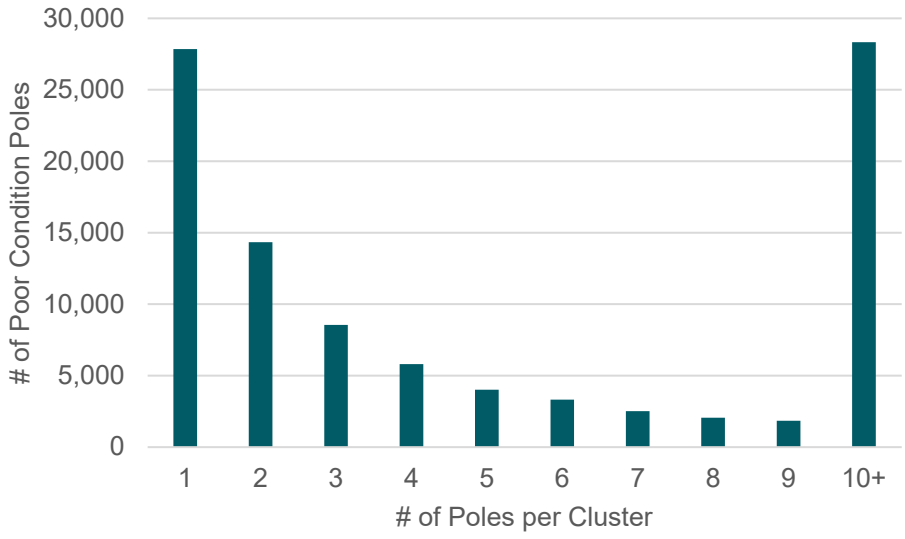


Figure 4: Number of Poor Condition Poles by Size of Cluster

1.3 POLE CONDITION

Pole condition deteriorates over time due to decay, rot, mechanical damage, environmental exposure, insect activity, and other degradation mechanisms. Hydro One monitors this deterioration through visual inspections conducted in accordance with the Distribution System Code and through the dedicated Test and Treat program.

Hydro One currently has approximately 99,000 poles in poor condition (see DSP Section 3.2, Subsection 3.2.3.1). These poles have reached a condition where they require replacement or refurbishment to mitigate risk of failure. As shown in Figure 5, without proactive intervention, the poor condition pole population is forecast to exceed 200,000 during the planning period.

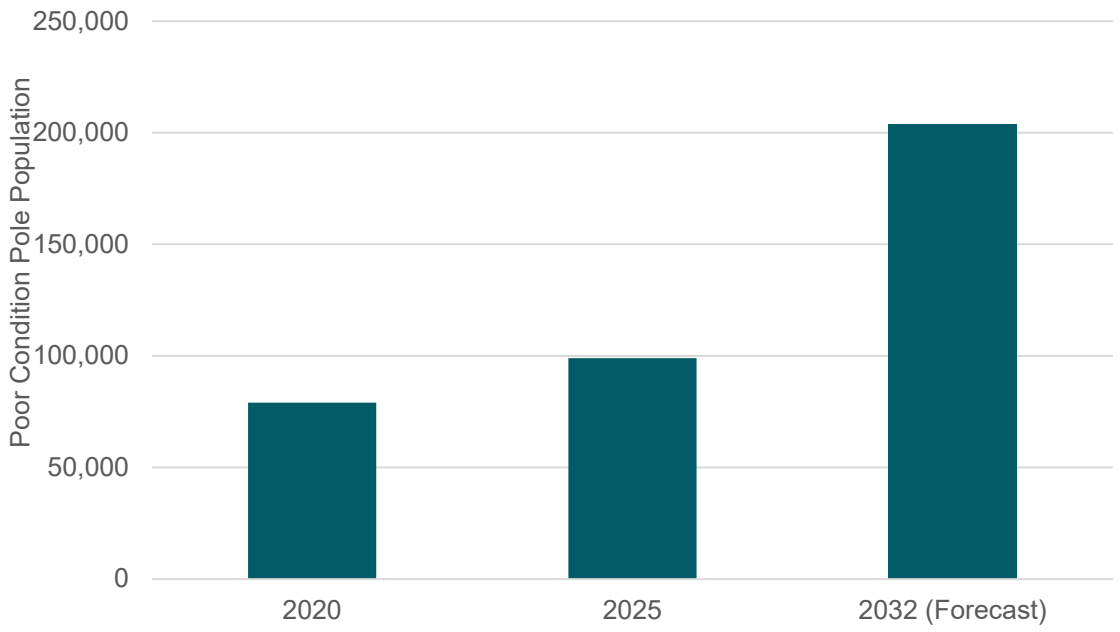


Figure 5: Forecasted Population of Poor Condition Poles to 2032 Without Intervention

The forecast demonstrates the continuing deterioration of the aging fleet. The projected growth in the poor condition pole population indicates that the historical sustainment levels have not kept pace with the continuing rate of deterioration. At current replacement rates,

the population of poor condition poles is expected to continue increasing absent a higher level of sustainment activity.

As the pole population continues to age, an increasing number of assets are expected to enter the oldest age cohorts, placing further pressure on future sustainment requirements. As poles deteriorate, their structural integrity is reduced, increasing their susceptibility to failure under normal operating conditions and during severe weather events. Without sustained renewal investment, continued growth in the poor condition pole population is expected to increase the likelihood of pole failures over time. Pole failures can result in public and worker safety hazards, environmental impacts, customer outages, and damage to connected distribution equipment. They can also lead to more emergency replacements, greater storm restoration requirements, and higher overall lifecycle costs. As a result, continued growth in the poor condition pole population would increase both the likelihood and consequences of asset failure, driving higher levels of system risk over time.

This investment will address existing poor condition poles and the continuing deterioration of the broader fleet to manage near- and long-term safety, reliability, resiliency, and environmental risks associated with pole failures. While the aging profile of the fleet will continue to drive new deterioration over time, Hydro One will, through coordinated inspection, refurbishment, replacement and clustered hardening activities, prioritize the highest-risk condition needs and materially limit growth in the poor condition pole population. These investments will reduce the likelihood and consequences of pole failures, including customer outages, public and worker safety hazards, environmental impacts, emergency replacements and increased storm restoration requirements.

1.4 RELIABILITY PERFORMANCE

Pole-related failures directly contribute to customer interruptions and can result in extended restoration times due to the need to replace failed structures and rebuild associated distribution infrastructure. Unplanned replacements are often prolonged, requiring emergency restoration under challenging operating conditions. When failures occur near the beginning of a feeder, thousands of customers downstream may be impacted.

On average, a pole-caused forced outage results in a 9.8-hour interruption (excluding Force Majeure events). By comparison, most planned pole replacements can be completed without any customer interruption and, where a planned outage is required, the average duration is 2.6 hours. Proactive intervention therefore allows Hydro One to manage deteriorated assets before failure, reducing the likelihood of prolonged customer outages and mitigating the safety, environmental and reliability risks that can arise when deteriorated poles fail unexpectedly.

As observed in Figure 6 below, Hydro One's historical performance data demonstrates an increasing trend in pole-caused interruptions, consistent with the aging demographics and deteriorating condition of the pole fleet.

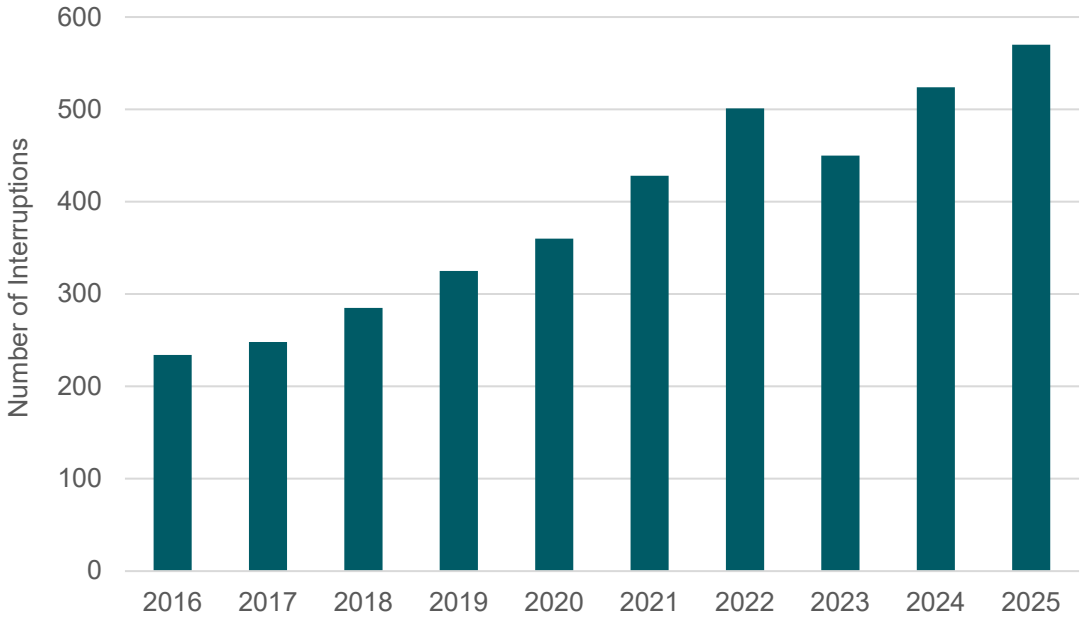


Figure 6: Pole Caused Interruptions Excluding FM

Historically, Hydro One prioritized poor condition poles using customer reliability consequences, identified through Customer Minutes Interrupted (CMI) and Risk Spend Efficiency (RSE) analysis. This risk-based approach directs investment toward assets whose failure would have the greatest impact on customers and system reliability.

CMI takes the total number of customers impacted by an outage and multiplies it by the interruption duration in minutes. For example, if a pole supplying 100 downstream customers fails and the outage lasts 300 minutes, the CMI would be 30,000. Using historical outage statistics, network topology, and downstream customer counts, a similar calculation is completed for each pole requiring replacement or refurbishment to determine the CMI impact if it were to fail. This CMI analysis assesses the reliability consequences of poor condition pole failures and informs prioritization.

Figure 7 shows the potential CMI impact of the current population of poor condition poles requiring replacement or refurbishment. Absent the proposed investment, the number of poor condition poles is expected to continue growing as the fleet ages, resulting in a corresponding increase in outage risk.

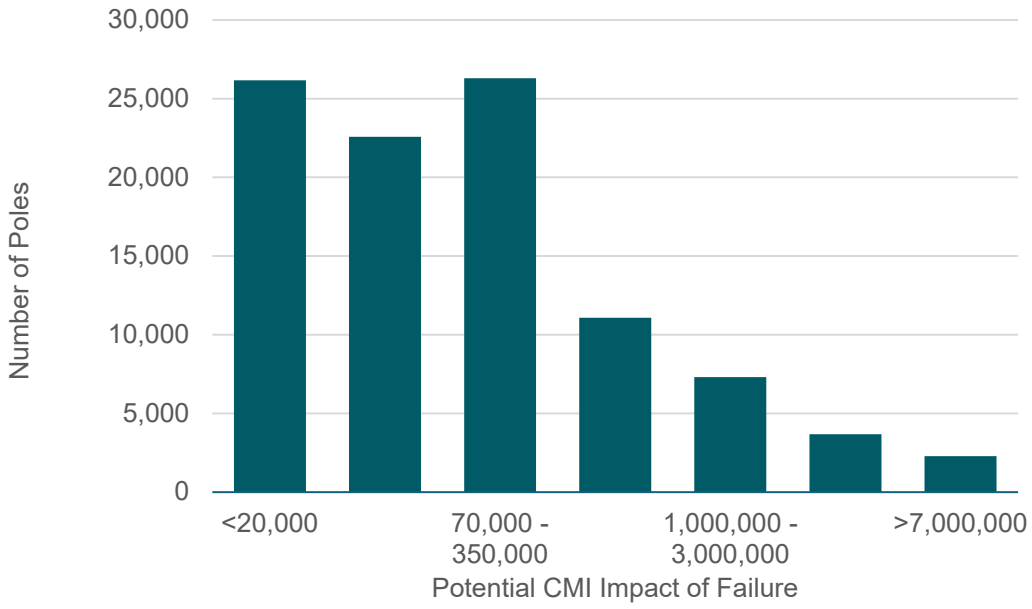


Figure 7: Distribution of Poles in Poor Condition by Potential CMI Impact of Failure

This prioritization has enabled Hydro One to direct limited sustainment investment toward the highest-consequence pole risks. As shown in Figure 8 and Figure 9, while the number of pole-caused interruptions during normal operating conditions has increased, the corresponding customer impact has increased at a slower rate.

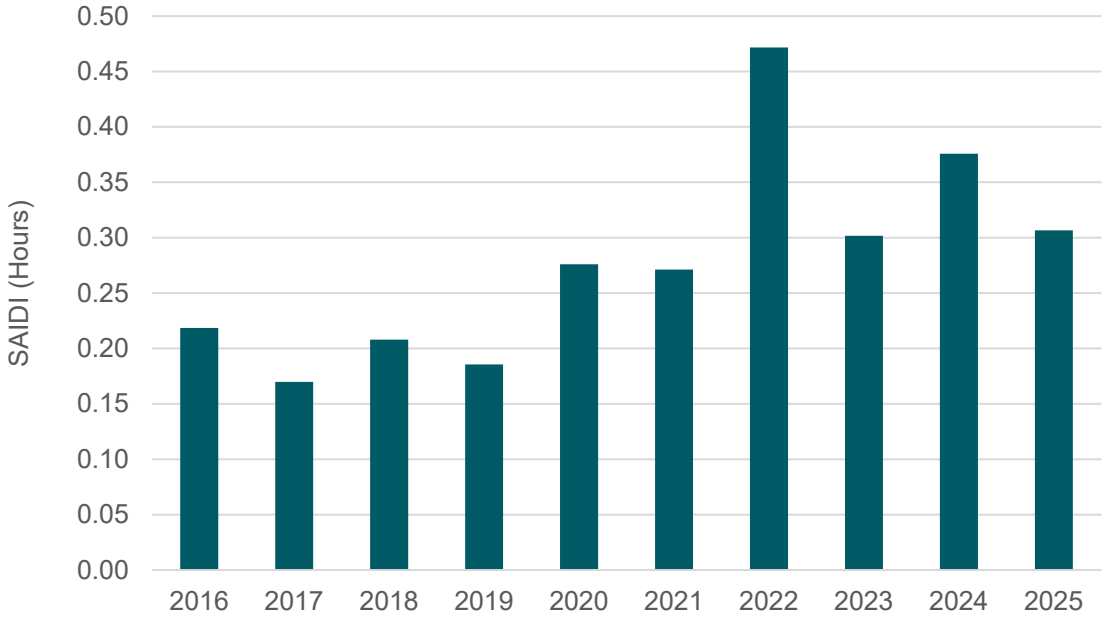


Figure 8: Pole Caused SAIDI (Excluding FM)

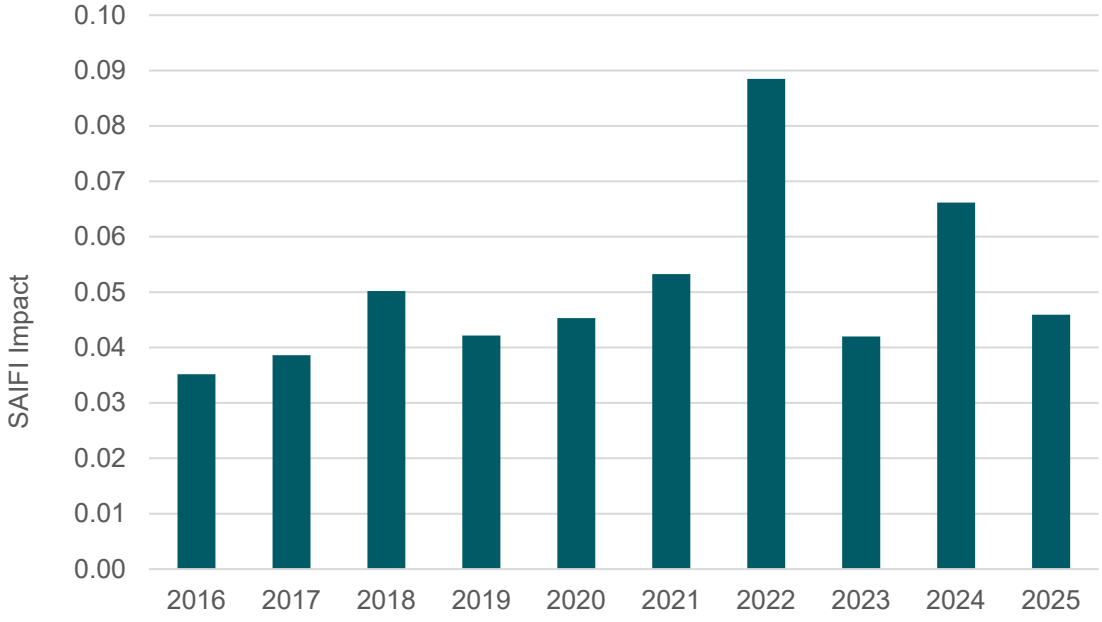


Figure 9: Pole Caused SAIFI (Excluding FM)

This demonstrates the value of Hydro One's existing risk-based prioritization. The historical strategy has focused available sustainment resources on those assets for which failure would have the greatest consequence for customers.

The proposed program continues this approach. However, the growing scale of deterioration means that continued individual prioritization alone is not sufficient to manage the long-term fleet condition trajectory. Hydro One must continue targeting high-consequence individual assets while also addressing the growing volume and geographic concentration of condition needs.

1.5 SEVERE WEATHER AND RESILIENCE

Ontario is facing increasingly frequent and severe weather events, such as ice storms and high wind events. As shown in Figure 10 below, Hydro One Distribution has experienced a sustained increase in the number of Force Majeure (FM) and storm days. In 2025, there were 62 Force Majeure and storm days, representing a 28% increase over the 10-year average from 2015-2024. More broadly, the five-year (2020-2024) average of 51.6 FM and storm days exceeds the 10-year (2015-2024) average of 48.4 days.

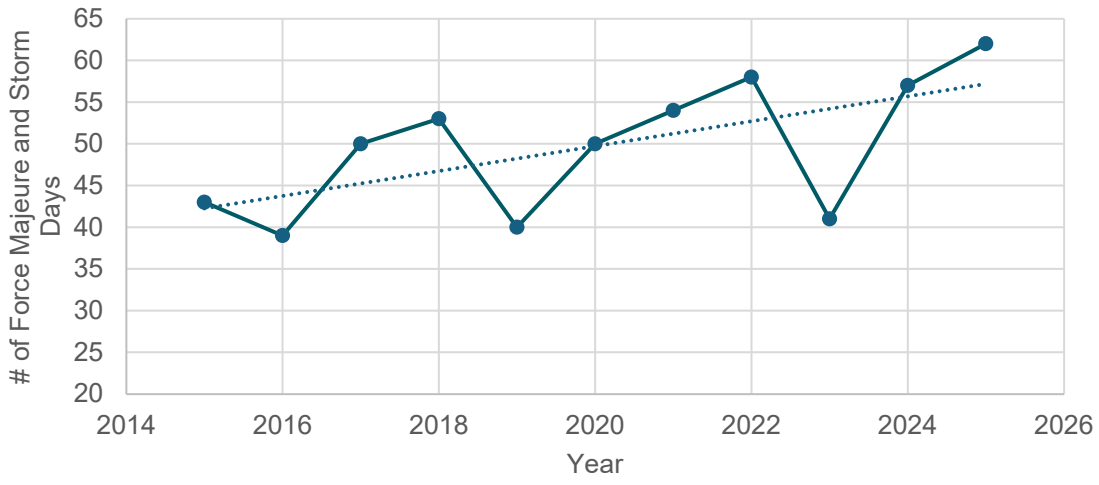


Figure 10: Storm and Force Majeure Days between 2015 and 2025

Severe weather can expose vulnerabilities within the pole fleet, particularly where poor condition poles are concentrated. During severe weather events, deteriorated poles are

subject to higher loading and environmental stress, increasing the likelihood of failure. Severe weather also increases the consequences of those failures because damaged infrastructure, challenging field conditions, and widespread system impacts can significantly extend restoration times. In addition, because severe weather can affect broad geographic areas, a single event can damage multiple poles simultaneously, particularly where neighbouring assets share similar service life, loading characteristics, construction standards, and environmental exposure. This creates the potential for cascading failures across larger sections of the distribution system, resulting in widespread outages and complex restoration efforts.

Hydro One's reportable reliability metrics provide only a partial view of this exposure because FM events are generally excluded from normal reliability reporting. As shown in Figure 11, the average duration of an unplanned pole-caused outage excluding FM events is 9.8 hours, compared to 41.9 hours for FM-related outages requiring pole replacement. This demonstrates that the consequences of pole failures are substantially greater during severe weather events and that the most consequential impacts of pole deterioration may not be fully reflected in historical reliability trends.

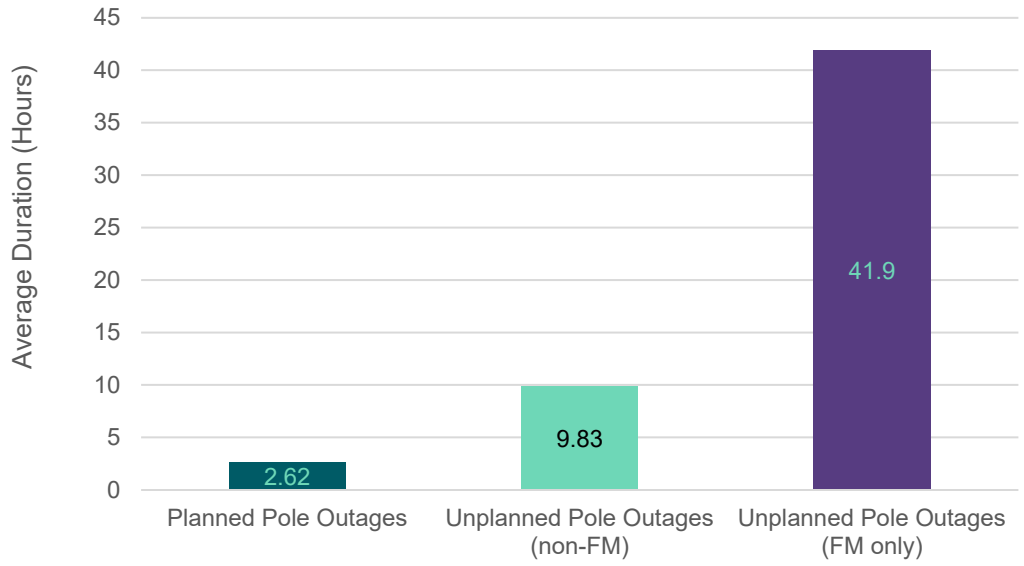


Figure 11: Pole Caused Outage Duration 2020-2024

The historical SAIDI results similarly demonstrate the greater consequences that pole failures can have during FM conditions. As shown in Figure 12, the recent five-year system average SAIDI indicates that pole-caused outages contribute nearly four times more SAIDI during FM events than during non-FM conditions.

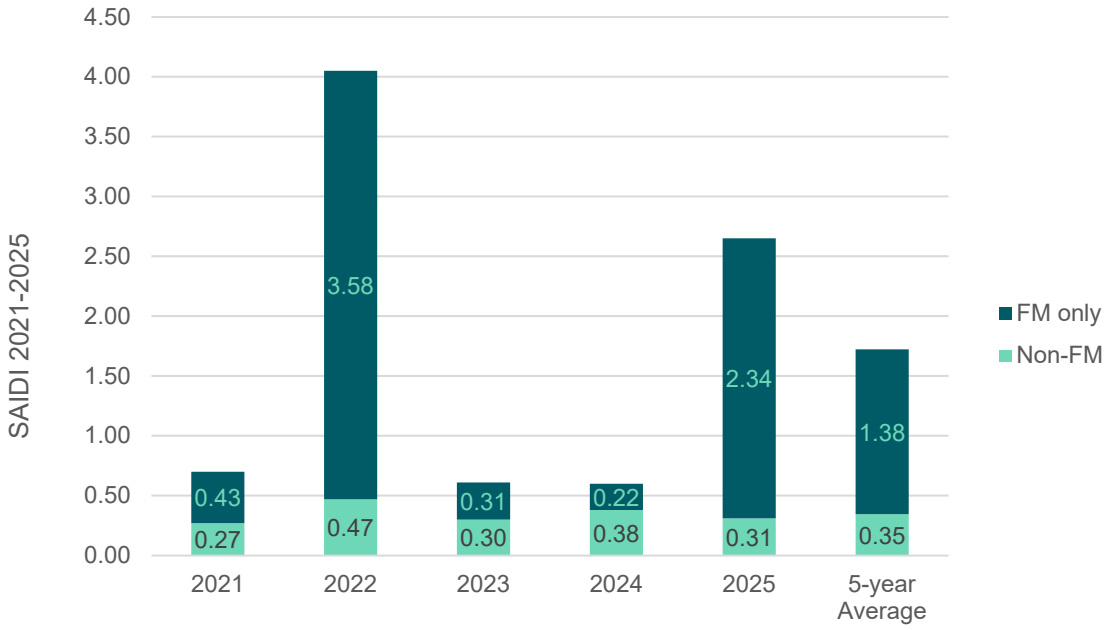


Figure 12: Pole caused SAIDI annually, including FM

Historical storm events further demonstrate the scale of these impacts. The May 2022 derecho and March 2025 ice storm resulted in approximately $306 million in restoration costs and approximately 73 million customer interruption hours across more than 2.1 million customer interruptions. These events also required the unplanned replacement of more than 5,000 poles. Beyond direct restoration costs, storm events strain operations through increased emergency response expenditures, mutual assistance requirements, and the deferral of planned preventative work due to prolonged restoration activities. Figure 13 provides examples of damage incurred during the 2025 ice storm.



Figure 13: Fallen Poles and Damaged Equipment, Orillia March-April 2025

Collectively, the evidence demonstrates that deteriorated poles present heightened risk during severe weather events, when failures are more likely to occur and customer impacts are significantly greater. Accordingly, Hydro One evaluates pole-related risk through both reliability and resilience considerations, incorporating severe-weather vulnerability alongside asset condition, customer impacts, and system risk when identifying and prioritizing investments in areas where deteriorated poles are concentrated.

2.0 INVESTMENT DESCRIPTION

Hydro One's Pole Sustainment program consists of four coordinated investment activities that address pole condition and reflect the nature and geographic concentration of identified condition needs.

- **Test and Treat** – Identifies poles that require replacement or mechanical refurbishment and chemically treats poles at the ground line to manage deterioration and extend service life;
- **Pole Refurbishment** – Restores mechanical strength by adding support to poor condition poles that meet the criteria for refurbishment;
- **Pole Replacement** – Replace individual poles in poor condition that cannot be refurbished and are geographically dispersed;

- **Clustered Hardening** – Replaces concentrations of poor condition poles within feeder sections in areas vulnerable to severe weather and installs stronger poles to improve system resilience.

Together these activities form an integrated asset management strategy for managing the condition and long-term risk of Hydro One's pole fleet.

Visual inspections through Distribution Line Patrols (see E-03-02, Subsection 2.2.4) and the Test and Treat program provide condition information and extend asset life where this can be done safely and economically. These programs collectively provide information regarding age, observed defects, structural deterioration, loading characteristics, and remaining strength.

Where poor condition is identified, Hydro One evaluates the appropriate intervention using established asset management criteria. Where deterioration is limited and structural integrity can be restored economically, the asset is mechanically refurbished through Pole Refurbishment activity. Where refurbishment is not technically feasible or no longer cost-effective, the pole is scheduled for replacement. Where replacement needs are geographically dispersed, poles are replaced individually (Pole Replacement). Where condition needs are concentrated within the same section of line, Hydro One addresses those needs through a clustered replacement approach that provides an opportunity to install higher-strength poles and improve the resilience of the renewed feeder section (Clustered Hardening).

As discussed in DSP Section 3.7, pole sustainment investments are selected using Hydro One's risk assessment approach. Investment decisions are informed by inputs such as condition information, reliability-risk analysis, customer impact, execution considerations, and coordination with other sustainment and resilience programs. This approach allows Hydro One to balance competing objectives while maintaining progress toward a sustainable long-term condition profile for the pole fleet.

The proposed investment combines continued assessment and treatment of the broader pole fleet with targeted intervention on identified poor condition poles. Tables 2, 3, and 4

summarize the planned volume of poles in the proposed investment throughout the five-year period for Hydro One, Orillia and Peterborough rate zones.

Table 2 - Test and Treat, Pole Refurbishment, Pole Replacement and Clustered Hardening Volumes - Hydro One

Description	Plan[1] 23-27	Act/Fcst[2] 23-27	2028	2029	2030	2031	2032	Total 28-32
Test and Treat	504,811	234,448	91,587	91,587	91,587	92,284	92,284	459,329
Pole Refurbishment	13,918	8,692	6,269	6,269	6,269	6,287	6,287	31,381
Pole Replacement	29,753	8,505	623	2,280	3,037	3,255	3,146	12,341
Clustered Hardening	-	-	1,571	8,083	8,089	11,226	12,387	41,356

Table 3 - Test and Treat, Pole Refurbishment, Pole Replacement and Clustered Hardening Volumes - Orillia RZ

Description	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Test and Treat	-	0	230	230	230	Embedded in Hydro One Networks		
Pole Refurbishment		0	2	2	2			
Pole Replacement		47	0	0	0			
Clustered Hardening		-	0	0	0			

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[2] "Act" refers to Actual (2023-25) and "Fcst" refers to Forecast (2026-27) expenditures.

Table 4 - Test and Treat, Pole Refurbishment, Pole Replacement and Clustered Hardening Volumes - Peterborough RZ

Description	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Test and Treat	-	0	467	467	467	Embedded in Hydro One Networks		
Pole Refurbishment		0	16	16	16			
Pole Replacement		85	264	259	254			
Clustered Hardening		-	0	0	0			

The proposed plan will test and treat approximately 461,420 poles and replace or refurbish 85,909 poles during the 2028-2032 period. The refurbishment and replacement volume comprises 31,435 pole refurbishments, 13,118 individual pole replacements, and 41,356 replacements through Clustered Hardening. This refurbishment and replacement plan is in line with the pacing preferred by Hydro One's customers for relocating or refurbishing 6% of all power lines (see SPF Section 1.6, Attachment 1, p. 550 - 552).

The proposed accomplishment level reflects both the existing population of approximately 99,000 poor condition poles and the continuing deterioration of the broader fleet as the assets continue to age during the rate period. Despite this ongoing deterioration, the proposed Pole Sustainment Program is expected to limit the poor condition pole population to approximately 135,000 poles by 2032, compared to more than 200,000 poles forecasted in poor condition without intervention. The program therefore avoids more than 65,000 additional poles deteriorating into poor condition and materially mitigates the growth in condition-related fleet risk, while prioritizing interventions based on reliability risk and customer consequences.

Figure 14 compares the current age profile with the forecast age profile in 2032 under the without-intervention and proposed investment scenarios. The proposed investment reduces the proportion of poles beyond expected service life relative to the without-intervention forecast, although continued sustainment investment will be required beyond 2032 as the fleet continues to age.

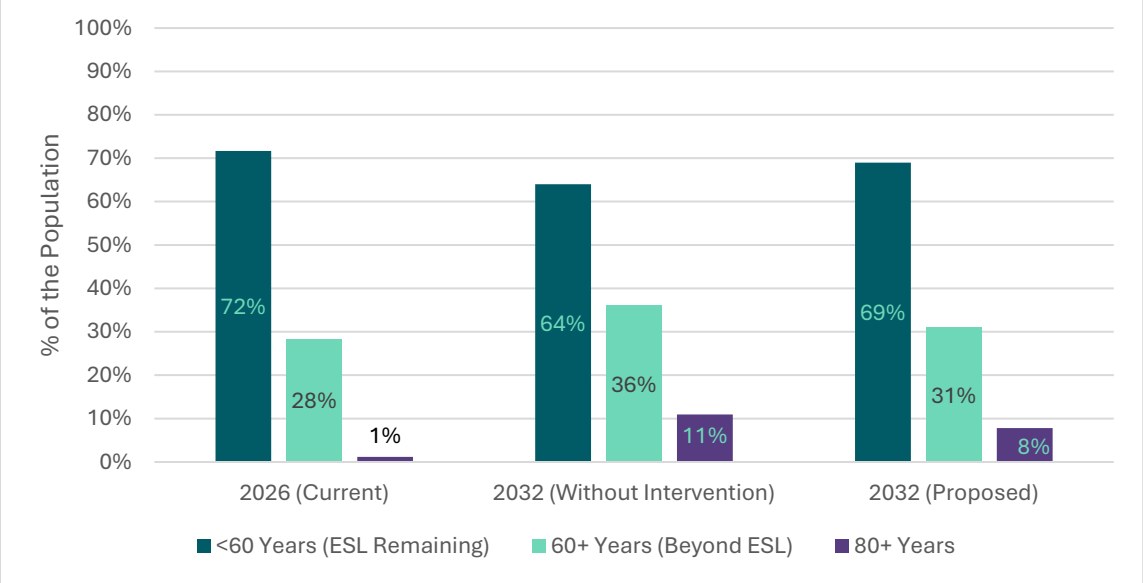


Figure 14: Forecasted Population beyond ESL

Hydro One prioritizes interventions based on risk and customer consequences. As shown in Figure 15, Hydro One's risk-based prioritization approach addresses poor condition poles with the highest potential CMI consequences first. As these higher-risk poles are addressed, the residual poor condition population is expected to become increasingly weighted toward poles with lower potential customer consequences.

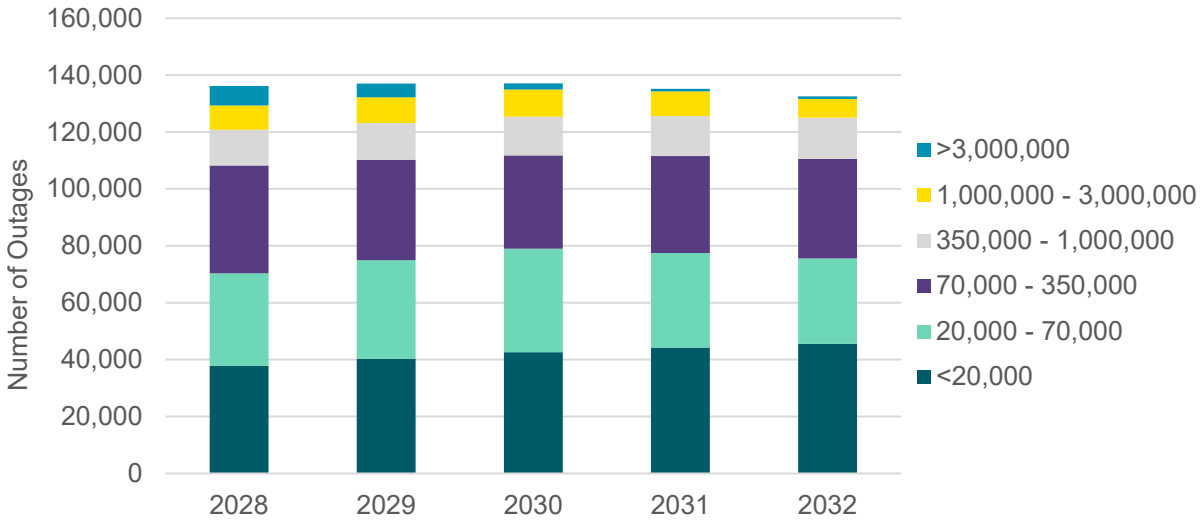


Figure 15: Number of Poor Condition Poles Over the Planning Period by CMI Impact

The proposed pace of investment is therefore expected to:

- Continue identifying deteriorated poles before failure occurs through condition-based inspection and testing;
- Extend asset life at the lowest practical cost through targeted refurbishment activities;
- Reduce customer reliability risk by prioritizing the replacement of poor condition poles with the greatest consequence of failure;
- Improve resilience by replacing concentrated groups of deteriorated poles and hardening in vulnerable areas; and
- Mitigate the long-term condition-related fleet risks by offsetting the increasing rate of deterioration associated with an aging asset base.

2.1 TEST AND TREAT

The Test and Treat program proactively assesses pole condition and chemically refurbishes poles through ground line treatment. The testing process involves visually assessing the exterior condition of the pole, drilling into the pole to measure remaining strength, and inserting a copper borate retreatment product to extend pole life. The data collected supplements pole condition data acquired through visual inspections and helps identify additional poles requiring replacement or mechanical refurbishment.

The proposed Test and Treat investment proactively tests and chemically refurbishes approximately 92,000 poles per year, reflecting an approximate 15-year cycle for eligible poles consistent with past practice. Newer poles, non-wood poles, and poles set in pavement or concrete are excluded from the Test and Treat program.

This activity reduces the need for premature replacement by preserving poles that remain suitable for continued service and provides the condition information required to direct more costly interventions toward assets for which those interventions are necessary.

2.2 POLE REFURBISHMENT

The Pole Refurbishment investment involves the installation of structural supports on poor condition poles as a cost-effective alternative to replacement. Refurbishment is an integral

component of managing the population of poor condition poles while minimizing costs to customers and allowing higher-risk poles to be prioritized for replacement.

Poles that qualify for refurbishment include those where damage is isolated to the ground line, poles that are on road, and poles in suitable soil conditions. Pole refurbishment is the preferred treatment option where technically feasible, as it can restore structural integrity at a lower cost than full replacement. A refurbished pole is expected to have an additional 20 years of service life and candidates are prioritized based on their reliability risk. This approach allows Hydro One to cost-effectively manage asset risk and extend pole life, reserving full replacement for assets that cannot be safely or effectively refurbished.

The proposed Pole Refurbishment investment structurally supports approximately 6,300 poles per year, or 31,500 poles during the 2028-2032 period.

Based on the current condition information, 44,500 poor condition poles are geographically dispersed and will be considered for refurbishment. Not all of these poles will meet the technical criteria for refurbishment. Poor condition poles that cannot be refurbished will be considered for individual replacement. This population will continue to evolve as additional poles deteriorate into poor condition during the planning period. Hydro One will continue to identify and prioritize these condition needs through its ongoing investment planning process.

2.3 POLE REPLACEMENT

The Pole Replacement investment addresses the replacement of poor condition poles that cannot be refurbished and are geographically dispersed. These poles are prioritized according to reliability risk and customer consequences.

The proposed Pole Replacement investment replaces approximately 2,600 poles per year or 13,000 over the 2028-2032 period. Together, Pole Refurbishment and Pole Replacement provide the two interventions required to address the 44,500 geographically dispersed poor condition poles. Hydro One will continue to identify and prioritize these needs as the condition of the fleet evolves during the planning period.

Hydro One refurbishes assets where service life can be safely and economically extended and uses individual replacement where refurbishment is not available. This enables Hydro One to manage dispersed condition requirements using the lowest-cost appropriate intervention while continuing to prioritize those assets presenting the greatest reliability consequence.

2.4 CLUSTERED HARDENING

Clustered hardening is a coordinated approach to address the large volume of poor condition poles that are concentrated within the same feeder section and share common exposure to age-related deterioration, environmental conditions, and loading characteristics. Hydro One defines a pole cluster as a group of three or more poor condition poles located in close proximity allowing for execution efficiencies. As shown in Figure 4, a substantial portion of poor condition poles are found in clusters containing 10 or more poles, reflecting the broader concentrations of condition needs identified across the system.

Replacing poles in clusters improves execution efficiency by reducing mobilization, planning, outage coordination, and construction costs relative to addressing the same assets individually over time. In locations vulnerable to severe weather, clustered replacements also provide an opportunity to improve system resilience through the installation of higher-strength poles designed to withstand greater mechanical loading that is associated with severe weather events. Resilience can be improved through several methods including increasing the class (strength) of the new poles being installed, optimizing span lengths, and installing stronger conductor and hardware.

Hydro One incorporated the results of Vulnerability Assessment and System Hardening (VASH) analysis into the assessment and prioritization of clustered hardening. As described in DSP section 3.6.6, Hydro One retained Guidehouse to assess the relative vulnerability of its overhead distribution system to high winds and ice accretion and to evaluate the potential customer value of system-hardening measures. The analysis considered projected climate conditions together with asset characteristics affecting vulnerability and subsequently incorporated historical Force Majeure performance and

customer consequence to identify feeders where resiliency measures could provide greater customer value.

Guidehouse's BCA for clustered pole hardening showed that the Benefit Cost Ratios (BCRs) increased as clustered hardening was targeted to progressively more vulnerable feeders, reaching 0.94 for the most-targeted sub-transmission and distribution Average Program Feeder group.[3] The results demonstrate measurable customer value by targeting higher-strength replacement poles to locations where poor condition assets and climate vulnerability coincide.

These results likely understate the value provided by the clustered hardening resilience measure because the analysis quantified Force Majeure resilience benefits only and did not quantify reliability benefits outside of Force Majeure events. The analysis also used a unit value of lost load derived from the ICE calculator[4], which may understate the value of lost load in FM events. Accordingly, Hydro One uses the VASH results as an additional resilience consideration within the broader risk-based assessment used to prioritize clustered hardening, and does not use the results as a stand-alone investment test. Further information on the VASH methodology and results is provided in DSP Section 3.6 Subsection 3.6.6 and DSP Section 3.3.

Candidate clusters are first identified where poor condition and deteriorated poles are concentrated within a common feeder section. Hydro One identified existing poor condition pole clusters via a system-wide GIS analysis. Based on the current condition information, approximately 54,500 poor condition poles are in clusters. This population will continue to evolve as additional poles deteriorate into poor condition, and inspection results will identify changes in the geographic concentration of condition needs during the planning period.

Candidate clusters are identified through a risk-based assessment process beginning with the identification of poor condition poles requiring replacement. Figures 16 and 17 below

[3] See DSP Section 3.3, Attachment 5 – Subsection 5.2.1
[4] Interruption Cost Estimate Calculator by Lawrence Berkeley National Laboratory.

illustrate how poor condition poles can form geographic clusters within a feeder section, allowing Hydro One to evaluate whether coordinated cluster replacement is the appropriate approach.



Figure 16: Poor condition Poles Located in Orleans, Ontario



Figure 17: Candidate Cluster of Poor Condition Poles

Hydro One then evaluates geographic concentrations of deteriorated poles within shared feeder sections and considers broader asset condition, customer impact, reliability performance, resilience benefits, and severe weather exposure. As part of this assessment, Hydro One considers whether these locations are subject to elevated severe-weather risk and whether the planned renewal provides an opportunity to install higher-strength poles capable of withstanding greater mechanical loading. This allows a single intervention to address both the underlying condition need and improve the resilience of the renewed feeder section to severe-weather events. Through this integrated approach, Hydro One can more efficiently address concentrated areas of pole deterioration, reduce long-term condition-related fleet risk, and direct hardening investments to locations where they are expected to provide the greatest resilience value for customers.

Clusters are risk-scored and prioritized to direct investment in areas providing the greatest overall value. Hydro One will continue to identify and prioritize clusters throughout the planning period to direct the investment toward higher-priority needs as the condition of the fleet evolves.

The proposed Clustered Hardening investment replaces 41,500 poles over the 2028-2032 period, or an average of approximately 8,300 poles annually. Hydro One will continue to identify and prioritize locations according to condition and risk and undertake the highest-priority work within the proposed expenditure envelope.

3.0 OUTCOMES

The objective of the pole sustainment program is to maintain the long-term health of the pole fleet by proactively identifying deterioration, extending asset life where it is technically feasible and cost-effective to do so, prioritizing replacement of the highest risk poles that have reached the end of their useful life, and addressing localized concentrations of deteriorated poles to manage system risk and mitigate the consequences of severe weather events.

The proposed program expands Hydro One's asset management approach beyond individual asset interventions and establishes a coordinated approach that combines

testing, refurbishment, targeted replacement, and clustered renewal to manage both short-term reliability risk and long-term fleet risk.

This investment delivers the following outcomes:

- Test and treat approximately 461,000 poles to manage ground line rot and proactively identify replacement and refurbishment needs. Proactive chemical retreatment of poles is expected to extend pole life by preventing further deterioration at the ground line. The test data collected from this activity also provides additional condition data to help identify poles at risk of failure.
- Refurbish, where possible, approximately 31,500 of the highest risk poles as a lower cost alternative to pole replacement. Individually replace approximately 13,000 of the highest risk poles, prioritized based on estimated CMI impact. Failure of these poles would have a significant reliability impact on customers. Replace approximately 41,500 deteriorated and poor condition poles within the same sections through clustered hardening. Where these clusters are in vulnerable locations, higher-class poles will be installed to harden that section to increase resilience to severe weather. Without refurbishment or replacement, these poles would remain at elevated risk of failure and associated customer impacts.
- Manage the long-term fleet risk profile by containing the growth in the poor condition pole population in 2032 to approximately 135,000. Absent intervention, this population is forecast to be greater than 200,000 by 2032.

The aging profile of the pole fleet presents a long-term risk as increasing deterioration rates continue to add poles to the poor condition population. This investment supports a risk level that can be efficiently sustained through planned renewal activities. The combined result is a more sustainable lifecycle position for the pole fleet.

3.1 OEB RRF OUTCOMES

Table 5 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	• Reduces the likelihood of customer interruptions by proactively renewing deteriorated wood poles before failure. • Manages impacts of severe weather by renewing vulnerable sections of feeder with higher-class poles.
Operational Effectiveness	• Contains growth in the number of poor condition poles to manage system risk at a sustainable level. • Maintains reliable operation of the distribution system by proactively targeting and addressing poor condition poles that pose the highest reliability risk. • Extends pole life through chemically retreating poles to mitigate ground line rot and prevent further deterioration at the ground line.
Public Policy Responsiveness	• Addresses localized asset condition risks and improves system resilience to severe weather aligned with the expectations of the VASH Report
Financial Performance	• Improves cost-effectiveness of asset renewal by coordinating renewal activities to reduce mobilization, planning, outage coordination, and construction costs. • Reduces lifecycle costs by chemically retreating suitable poles to extend their life. • Mitigates the impact of storm, long-term maintenance, and outage costs through proactive asset renewal and hardening.

4.0 EXPENDITURE PLAN

Tables 6, 7, and 8 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 rate period. Tables 9, 10, and 11 provide a breakdown of net capital expenditures by pole sustainment program for Hydro One, Orillia RZ, and Peterborough RZ.

Table 6 - Hydro One - Investment Expenditures[5]

($M)	Plan[6] 23-27	Act/Fcst[7] 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	443.4	198.2	61.4	191.8	212.1	274.9	303.2	1,043.5
Less Removals	52.6	20.6	7.1	22.7	25.2	32.9	36.3	124.2
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**390.8**	**177.7**	**54.3**	**169.1**	**187.0**	**242.0**	**266.9**	**919.3**

[5] Figures presented in the tables may not sum to the totals shown due to rounding.
[6] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[7] "Act" refers to Actual (2023-25) and "Fcst" refers to Forecast (2026-27) expenditures.

Table 7 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	N/A	0.58	0.02	0.02	0.02	Embedded in Hydro One Networks		
Less Removals		0.09	0.00	0.00	0.00			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.48**	**0.02**	**0.02**	**0.02**			

Table 8 - Peterborough RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	N/A	0.92	2.95	3.01	3.07	Embedded in Hydro One Networks		
Less Removals		0.12	0.52	0.53	0.55			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.80**	**2.42**	**2.47**	**2.52**			

Table 9 - Program Level Breakdown of Pole Sustainment Expenditures - Hydro One

($M) Net Capital Expenditures	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Pole Test and Treat	54.1	28.6	10.6	10.9	11.1	11.4	11.6	55.6
Pole Refurbishment	33.4	13.3	12.7	13.0	13.2	13.6	13.8	66.3
Pole Replacement	303.3	135.7	8.9	33.8	46.8	52.1	52.3	193.8
Clustered Hardening	-	-	22.0	111.5	115.9	165.0	189.2	603.6
Total	**390.8**	**177.7**	**54.3**	**169.1**	**187.0**	**242.0**	**266.9**	**919.3**

Table 10 - Program Level Breakdown of Pole Sustainment Expenditures - Orillia RZ

($M) Net Capital Expenditures	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Pole Test and Treat	N/A	0.02	0.02	0.02	0.02	Embedded in Hydro One Networks		
Pole Refurbishment		0.00	0.00	0.00	0.00			
Pole Replacement		0.47	0.00	0.00	0.00			
Clustered Hardening		N/A	0.00	0.00	0.00			
Total		**0.48**	**0.02**	**0.02**	**0.02**			

Table 11 - Program Level Breakdown of Pole Sustainment Expenditures - Peterborough RZ

($M) Net Capital Expenditures	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Pole Test and Treat	N/A	0.14	0.03	0.03	0.04	Embedded in Hydro One Networks		
Pole Refurbishment		0.00	0.02	0.02	0.02			
Pole Replacement		0.65	2.37	2.41	2.46			
Clustered Hardening		NA	0.00	0.00	0.00			
Total		**0.80**	**2.42**	**2.47**	**2.52**			

The factors influencing pole sustainment costs include:

- The types of poles requiring replacement (i.e., pole height, pole class, number of circuits, etc.);
- The location and 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.

2023-2027 EXPENDITURES

Hydro One forecasts net capital expenditures of $177.7M over the 2023-2027 rate period, approximately $213.1M lower than planned. The variance is attributable to lower work volumes across the program, resulting from the re-prioritization of capital and delivery resources during the current rate period and broader market-based cost pressures (see SPF Section 1.8, Subsection 1.8.3) affecting the delivery of the work.

As outlined in Table 2, Hydro One forecasts 17,197 pole replacements and refurbishments, compared with approximately 43,671 planned, and approximately 234,448 Test and Treat activities, compared with approximately 504,811 planned. The lower-than-planned work volumes resulted in part from the reprioritization of capital and delivery resources toward mandatory and higher-priority requirements that emerged during the rate period, including customer- and demand-driven investments, storm restoration activities, and compliance-related obligations. These factors are discussed in greater detail in DSP Section 3.9.

Work volumes were also affected by broader market cost pressures experienced during the period (discussed in SPF Section 1.8, Subsection 1.8.3), including increases in material and contractor costs, which increased the cost of delivering pole sustainment work within the available program resources. Costs were also affected by the in-year reprioritization of work volumes to lower levels and the resulting adjustments to planned delivery activities. Collectively, these factors contributed to lower accomplishment levels than planned over the 2023-2027 period.

As a result, the pole fleet continued to deteriorate over the current rate period. The poor condition pole population increased from approximately 79,000 in 2020 to approximately 99,000 currently, while recent inspection results continue to identify approximately 15,000 additional poor condition poles annually. The growth in the poor condition pole population reflects both the lower-than-planned level of sustainment activity and the ongoing aging of the fleet. Addressing this accumulated condition risk is a key driver of the increased pole replacement, refurbishment, and Test and Treat activity proposed for the 2028-2032 planning period.

2028-2032 EXPENDITURES

Hydro One forecasts net capital expenditures of $919.3 million over the 2028-2032 planning period, significantly higher than in the 2023-2027 period. The increase reflects a higher level of sustainment activity required to address the current and forecasted condition of the pole fleet. Specifically, the proposed investment responds to the growing population of poor condition poles that require remediation or replacement to mitigate increasingly significant safety, reliability, and operational risks. The forecast also reflects the need to enhance system resilience in the face of more frequent and severe weather

events, which increase both the likelihood and consequences of pole failures. In addition to these increased investment requirements, forecast expenditures are further influenced by higher unit costs associated with delivering sustainment work. Together, these factors contribute to the increase in forecast expenditures for the program.

Pole Test and Treat activity is expected to increase from 234,448 poles during 2023-2027 to 461,420 poles during 2028-2032, restoring the activity to the 15-year cycle. Pole replacement and mechanical refurbishment activity is expected to increase from 17,197 poles during 2023-2027 to 44,553 poles during 2028-2032. The Clustered Hardening program – a new investment activity in Pole Sustainment program – is expected to replace 41,356 poles during the 2028-2032 rate period. In total, 85,909 poles will be replaced and/or strengthened, or refurbished during the 2028-2032 rate period. These increased work volumes reflect the forward-looking condition-based investment requirements of the pole fleet.

The increase in capital expenditures also reflects broader execution cost pressures incorporated into the forecast cost of delivering the work. Forecast expenditures are based on unit-price estimates informed by Hydro One's historical costs. As a result, in addition to the increase in condition-based investment needs, higher unit costs are a significant contributor to the forecast expenditure increase for this program.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: REACTIVE REPLACEMENTS

Under this alternative, Hydro One would rely principally on a reactive replacement approach, whereby failed poles would be addressed solely through the Trouble Call and Storm Damage Response Program (DSP Section 3.11, D-SR-05). Under this alternative, Hydro One would not test and treat poles, structurally refurbish poles, or proactively replace poles. Instead, pole condition would be monitored primarily through patrols performed as part of lines maintenance programs, and poles that have failed or present an immediate public safety issue will be replaced on a reactive basis.

This alternative was rejected because reactive replacement is a more costly approach to managing long-term pole fleet condition. Without proactive inspection, refurbishment, and replacement activities, the population of poor condition poles would continue to grow, resulting in a greater number of failures requiring unplanned and emergency replacement. These replacements are generally less efficient and more costly than planned refurbishment or replacement programs and would increase storm restoration costs and other unplanned expenditures. Over time, the growing population of poor condition poles would also contribute to degraded reliability and increased public safety risk.

ALTERNATIVE 2: ACCELERATED REPLACEMENT

This alternative would align with the accelerated pacing proposed to Hydro One's customers for relocating or refurbishing 9% of all power lines (see SPF Section 1.6, Attachment 1, p. 550 - 552). This alternative would test and treat poles on a 15-year cycle, structurally refurbish 7,000 poles per year, and replace 21,000 poles per year. Relative to the proposed plan, it would accelerate remediation of poor condition poles and reduce the poor condition pole population to approximately 80,000 by 2032, broadly returning the fleet to the level observed when Hydro One filed its application for 2023-2027 rates in 2021.

Hydro One rejected this alternative because the additional reduction in fleet risk would require a materially higher level of expenditure than the proposed plan. This higher-cost approach was not supported by customer engagement results, which identified affordability as a key priority (SPF Section 1.6, Attachment 1, pp. 587, 648, 700, and 786), while fewer than 30% of customers supported this accelerated pacing in the Phase 2 Customer Engagement Survey (SPF Section 1.6, Attachment 1, p. 551).

ALTERNATIVE 3: ADDRESS HIGHEST-RISK POLES (RECOMMENDED)

Under this preferred alternative, Hydro One Distribution will control growth in system risk at an investment level that is lower than the accelerated pace described in Alternative 2. This will be achieved by restoring the Test and Treat program to its historical cycle, maintaining replacement volumes at a level that targets the highest-risk assets, and increasing the use of cost-effective refurbishments. Under this alternative, Hydro One will test and treat poles on a 15-year cycle, structurally refurbish approximately 6,300 poles per year, and replace approximately 11,000 poles per year.

Witness: Paul Ankrett; Gianni DiFilippo

In total, this alternative will address approximately 86,000 poor condition and deteriorated poles by targeting individual poles and geographic clusters of poles that pose the highest risk to customer reliability and system resilience. The proposed pace of investment is expected to limit the poor condition pole population to approximately 135,000 poles by 2032, compared to more than 200,000 poles without intervention. While this represents an increase from the current population of approximately 99,000 poor condition poles, it materially mitigates the growth in condition-related fleet risk associated with an aging asset base.

Hydro One expects to see combined benefits from continued reduction in high-consequence individual poles as well as increased execution efficiency through coordinated cluster replacements.

While customers generally supported distribution investment to improve day-to-day reliability and resilience to severe weather, Hydro One reduced the proposed investment portfolio in response to affordability considerations and broader customer feedback, as described in DSP Section 3.7. This alternative is recommended because it balances long-term risk reduction, customer reliability and resilience benefits, and affordability, while maintaining a reasonable level of investment to manage long-term pole fleet risk.

6.0 EXECUTION RISK AND MITIGATION

The Pole Sustainment Program reflects Hydro One's assessment of the execution risks and delivery requirements associated with increased sustainment work volumes. In developing the program, Hydro One considered factors such as material availability, outage coordination, fleet and equipment requirements, and site-specific construction conditions. These considerations informed the proposed scope and pacing of the investment and support Hydro One's readiness to safely and efficiently execute the program throughout the rate period.

Material Availability

The Pole Sustainment Program is dependent on the availability of poles, hardware, and other associated distribution equipment. Delays in material availability or extended manufacturing lead times could impact construction schedules and program execution.

Hydro One mitigates these risks through established supply chain management practices, including advance procurement planning, strategic inventory management, supplier performance monitoring, and ongoing assessment of material availability.

Outage Coordination

Hydro One manages outage-related risks through established outage planning and system coordination processes. Planned outages are coordinated across the organization to balance customer impacts, system reliability requirements, and competing work priorities. Where practical, multiple work activities are bundled into a single outage to maximize productivity and minimize customer impacts. The Clustered Hardening Program further supports efficient outage utilization by enabling multiple pole replacements within the same section to be completed during a coordinated outage window, improving productivity, and reducing customer disruption.

Fleet and Equipment Availability

Delivery of the Pole Sustainment Program requires access to specialized construction equipment and fleet resources. Hydro One works closely with Lines of Businesses to forecast equipment requirements and align fleet availability with planned work volumes. Equipment utilization and fleet requirements are continuously monitored to support efficient deployment of fleet resources. Where required, external rental options are available to supplement fleet capacity and support program execution.

Site Conditions, Access, and Permitting

Pole sustainment work is performed across Hydro One's service territory, which includes urban, rural, remote, off-road, and environmentally sensitive locations. Construction activities may be influenced by site-specific conditions such as rock excavation requirements, seasonal access restrictions, and challenging terrain. Hydro One incorporates these considerations into project planning and scheduling activities to support efficient execution. Construction activities are sequenced, where practical, to take advantage of favorable seasonal conditions and improve access to challenging locations. Further discussion of these delivery factors is provided in DSP Section 3.10.

D-SR-08	DISTRIBUTION LINES MINOR COMPONENT REPLACEMENT
Primary Trigger:	Obsolescence/Compliance
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	27.8	25.1	25.6	26.4	26.9	131.7
Orillia RZ	0.07	0.07	0.08	Embedded in Hydro One Networks		
Peterborough RZ	0.07	0.07	0.07			

Summary:

This investment involves the replacement of minor distribution line components not addressed under other lines-related distribution capital investments, including poor condition cross arms, substandard and obsolete transformers, substandard and obsolete communicating fault circuit indicators (CFCIs), 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 CFCIs), and compliance (in the case of nest platforms and sentinel lights). This investment is expected to improve reliability, reduce outage risk, maintain operational effectiveness, and fulfill Hydro One's customer service and regulatory obligations with respect to these assets.

1.0 INVESTMENT NEED

Hydro One's distribution system includes approximately 126,000 circuit kilometers of primary lines that deliver electricity to customers across the province. Through routine inspections, line patrols, remote monitoring, and engineering assessments, Hydro One identifies components that have deteriorated due to age and condition, become obsolete because of technological change, or require intervention to address safety and compliance obligations.

Planned replacement of major distribution line assets is primarily undertaken through dedicated capital investments, including pole sustainment (DSP Section, D-SR-07), submarine cable replacement (DSP Section D-SR-09), underground cable replacement (D-SR-15), and Distribution Lines Sustainment Initiatives (DSP Section D-SR-10). In addition, localized defects that can be addressed through maintenance activities are managed through OM&A programs.

Despite these programs, several critical asset populations remain that are not effectively addressed through either major capital investments or maintenance activities. Failure to address these components would increase customer outage risk, extend restoration times, reduce operational effectiveness, create safety concerns, and impair Hydro One's ability to satisfy regulatory and customer obligations. This investment addresses those residual risks through targeted replacement and refurbishment activities focused on:

- Cross arms;
- Substandard transformers;
- Communicating fault circuit indicators (CFCIs);
- Nest platforms; and
- Sentinel lights.

The following describes these distribution lines 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 14,000 cross arms, representing roughly 3% of Hydro One’s 500,000 cross arms, have been identified as being in poor condition. In addition, Hydro One expects further cross arms currently assessed as fair condition to deteriorate into poor condition during the 2028-2032 period. Accordingly, the planned replacement volumes reflect both the existing poor condition population and forecast deterioration over the planning period.

Cross arm failures can have significant customer reliability consequences because a single failure can interrupt multiple conductors and affect a large number of downstream customers. While a typical cross arm failure results in approximately 100,000 customer minutes interrupted ("CMI"), severe events can exceed 1,000,000 CMI.

For example, in 2024 a cross arm failure in the Nipissing area resulted in a seven-hour outage affecting approximately 2,200 customers, equivalent to approximately 920,000 CMI.

The risk associated with cross arm failure has increased in recent years. As shown in Figure 1, outages attributable to cross arm failures have more than doubled over the last decade. This trend reflects both the aging asset population and the deferral of some planned replacement work in favour of higher-priority system investments. The proposed investment targets those cross arms with the highest potential customer impact should failure occur.

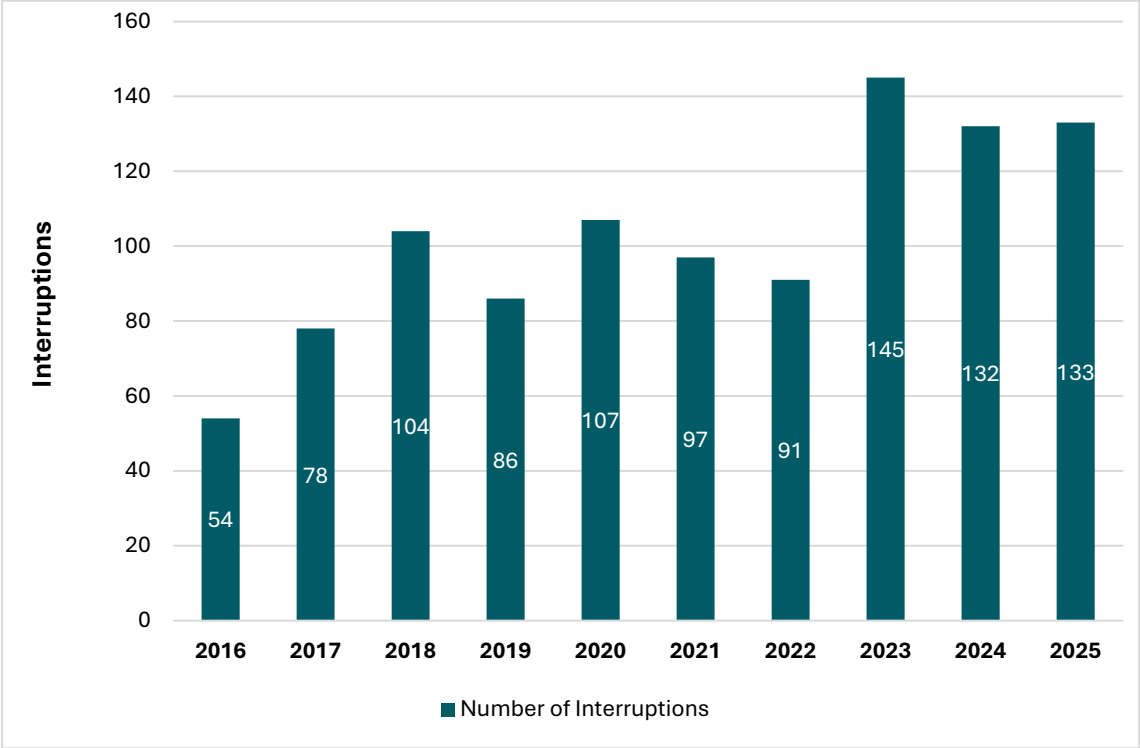


Figure 1: Number of Interruptions Attributed to Cross arm Failures (Excluding Force Majeure Events)

SUBSTANDARD TRANSFORMERS

Overhead transformers installed in underground-type enclosures and transformers installed within steel poles have been identified as obsolete or substandard. Approximately 800 transformers fall within these categories. These installations pose operational and safety risks.

These installations also present elevated customer reliability risks. Many units cannot be replaced on a like-for-like basis following failure and are located in difficult-to-access areas that require extensive planning, engineering, and customer coordination. As a result, an unplanned transformer failure may lead to significantly longer outage durations than would otherwise be experienced for a standard transformer failure.

Overhead transformers installed in underground-type enclosures present two distinct concerns. First, installations located inside buildings are difficult to access for maintenance and repair. Second, installations in uninsulated metal boxes on the ground pose a potential public safety risk. In the event of failure, some of these transformers may be impossible to replace on a like-for-like basis and may require an extended outage and significant emergency work to relocate.

Transformers installed within steel poles (see Figure 2 below) have a compact design that results in insufficient operating clearances. These transformers are no longer available as a standard like-for-like replacement unit, and their replacement requires outages to install padmount transformers.

Completing this work under a planned investment reduces outage time and customer impact compared to completing it on a demand basis in response to an unplanned failure. To address these risks, Hydro One replaces these transformers with standard transformers, reconfiguring as needed.



Figure 2: Pole Transformer

COMMUNICATING FAULT CIRCUIT INDICATORS

CFCIs remotely communicate fault magnitudes and locations on distribution lines to Hydro One. Knowing the approximate location of a fault eliminates the need to send staff to patrol the entire circuit and can reduce restoration times by several hours. Without functioning CFCIs, crews may need to inspect lengthy sections of distribution line to locate faults, increasing outage duration and extending service interruptions for customers. There are approximately 9,000 CFCIs installed on Hydro One's distribution network.

In addition, Hydro One's Advanced Distribution Management System (ADMS) leverages CFCI telemetry data by analyzing it in real time to assess load transfer scenarios. This helps mitigate the overloading of a feeder, especially during seasonal peaks. CFCI devices also provide more accurate year-round data and replace reliance on labour-intensive electronic recording ammeters installed for a short period at critical locations, such as feeder heads, to provide seasonal power consumption data.

Certain installed CFCIs are nearing end of life, are defective, or will become obsolete due to technological change. CFCIs have a useful life of approximately ten years, with battery capability most often being the limiting factor. Defective units are no longer able to communicate effectively with the ADMS due to software or hardware failure. Technological change also drives obsolescence. CFCI devices require a cellular connection to communicate remotely with ADMS. Older devices rely on 3G networks, which telecommunications providers, such as Bell, have publicly announced will be decommissioned nationally starting March 1, 2027. Devices dependent on 3G connectivity will become obsolete upon decommissioning.



Figure 3: CFCI Installation on a Feeder

NEST PLATFORMS

Bird nests on distribution poles can 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 contact distribution lines, causing outages to downstream customers and potentially resulting in the injury or death of the bird.

Bird nests are identified through regular inspection of distribution lines. When nests are identified, they must be relocated to safeguard the integrity of the distribution system and comply with all applicable regulations, including the *Migratory Birds Convention Act, 1994*. Figure 4 below shows a bird nest required to be addressed through such work.



Figure 4: 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 obligated to maintain existing installations. Sentinel light failures are generally identified by Hydro One customers directly and are reactively addressed as they occur.

2.0 INVESTMENT DESCRIPTION

This investment addresses the replacement or refurbishment of minor distribution line components and includes the following types of work.

CROSS ARMS

Cross arms identified as being in poor condition, and those expected to deteriorate into poor condition by 2032, are candidates for inclusion in the cross arm replacement investment. Currently, approximately 14,000 cross arms have been assessed to be in poor condition. Based on recent inspection results, Hydro One has identified approximately 1,650 additional cross arms entering poor condition annually. Accordingly, the planned replacement volume reflects both the existing poor condition inventory and forecast deterioration that is expected to occur over the next seven years (2026-2032 period).

Hydro One's proposed replacement volumes are expected to stabilize and modestly improve overall cross arm condition by addressing the highest-risk portions of the population. While deterioration will continue across some portions of the asset base, the replacement program operates in conjunction with cross arm replacements completed through the pole replacement and trouble programs. Taken together, these activities are expected to reduce customer outage risk and improve the overall condition of the cross arm population over the 2028-2032 period.

Cross arms are selected for replacement based on the projected impact of failure, measured by 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 planned for replacement under this investment.

Table 1 - Number of Cross Arms to be Replaced in the Plan Period

Zone	Plan 23-27	Forecast 23-27	Total 28-32
Hydro One	8,417	6,055	15,010
Orillia RZ	-	6	40
Peterborough RZ	-	15	20

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 considered for replacement as part of the pole sustainment program (DSP Section 3.11, D-SR-07). Cross arms that do not undergo planned replacement and fail during the planning period are replaced as part of the trouble program. Based on the proposed replacement rate, Hydro One forecasts stabilization and modest improvement in overall cross arm condition over the planning period. By prioritizing assets with the greatest potential customer impact in the event of failure, the program is also expected to reduce interruptions attributable to cross arm failures.

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 forecast to be replaced as part of this investment. The majority of the planned replacement volume reflects the remaining population of identified substandard transformers, including units that were deferred during the 2023-2027 period as Hydro One prioritized other investments with more immediate reliability, operational, or compliance requirements.

These transformers present operational and safety risks due to their space-constrained and obsolete designs. Replacing these substandard transformers proactively under a planned program is more efficient and cost-effective than replacing them on demand in response to failure. A significant number of the units are in difficult-to-access locations, such as underground enclosures in condominium buildings, which requires a higher degree of planning and coordination to execute the work.

Table 2 - Number of Transformers to be Replaced in the Plan Period

Zone	Plan 23-27	Forecast 23-27	Total 28-32
Hydro One	722	94	785
Orillia RZ		0	5
Peterborough RZ		1	5

COMMUNICATING FAULT CIRCUIT INDICATORS

CFCI devices provide critical fault-location data that supports the reliable operation of Hydro One's distribution network. By eliminating the need to patrol lengthy sections of line to identify faults, these devices can reduce restoration times by several hours and help minimize outage duration for customers.

In addition to their reliability benefits, CFCIs are relatively low-cost devices that reduce labour costs associated with outage response by facilitating efficient dispatch of field staff to a specific geographic area rather than requiring a full line patrol. Replacing end-of-life, defective, and obsolete CFCI devices improves Hydro One's ability to respond to outages in a timely and cost-effective manner and provides the benefits of remote grid visibility. Table 3 provides the number of CFCI devices to be replaced under this investment.

Table 3 - Number of CFCI Devices to be Replaced in the Plan Period

Zone	Plan 23-27	Forecast 23-27	Total 28-32
Hydro One	-	-	4,350
Orillia RZ	-	-	0
Peterborough RZ	-	-	0

Of the CFCI units planned to be replaced during the 2028-2032 planning period, approximately 3,350 are driven by defective status or end of life and 1,000 are driven by obsolescence. The replacement of CFCIs is generally more economical than repair, considering that labour costs must be incurred under both scenarios, and given the benefit of manufacturer warranty and support on new units (CFCI unit costs are relatively minor).

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 4 shows the forecasted number of nests that will be addressed during the planning period based on historical volumes of nest hazards. The actual volume of nest hazards discovered by Hydro One over the 2023-2026 period exceeded plan.

Table 4 - Number of Nests to be Addressed in the Plan Period

Zone	Plan 23-27	Forecast 23-27	Total 28-32
Hydro One	65	68	85
Orillia RZ	0	2	5
Peterborough RZ	0	2	5

SENTINEL LIGHTS

This investment replaces failed sentinel lights and removes sentinel lights and poles at the termination of rental contracts. This is a demand investment 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 currently under contract;
- Removal and disposal of sentinel lights at the termination of current contracts; and
- Removal of sentinel light rental poles at the termination of current contracts.

Table 5 shows the forecast number of sentinel lights that will be replaced or removed during the planning period, based on historic accomplishment levels. Since no new sentinel light agreements are being made and customers can terminate their rental agreements at any time, the number of active sentinel light installations is expected to decrease over time. The higher forecast accomplishment compared to plan for the 2023-2027 period is mainly attributable to a one-time initiative to remove sentinel lights of a vintage with the highest PCB risk. This PCB-related initiative is planned to be completed in 2026, and volumes will return to historic levels.

Table 5 - Number of Sentinel Lights to be Replaced or Removed in the Plan Period

Zone	Plan 23-27	Forecast 23-27	Total 28-32
Hydro One	7,004	13,964	8,725
Orillia RZ	0	1	0
Peterborough RZ	0	21	25

3.0 OUTCOMES

Hydro One aims to achieve the following outcomes as a result of this investment:

- Improved reliability through targeted replacement of poor condition cross arms, prioritized based on customer impact;
- Reduced outage duration through replacement of substandard transformers and improved service restoration capability through replacement of obsolete or end-of-life CFCI devices;
- Reduced reliability risks due to bird nests while complying with applicable environmental legislation; and
- Replacement and removal of sentinel lights in accordance with existing rental agreements.

Together, these investments address asset populations that would otherwise fall outside Hydro One's major sustainment programs while addressing reliability, operational, safety, and compliance risks. The program represents a cost-effective means of reducing outage risk and maintaining customer service levels across Hydro One's distribution network.

3.1 OEB RRF OUTCOMES

The following table presents anticipated benefits of this investment in accordance with the Ontario Energy Board’s Renewed Regulatory Framework:

Table 6 - Outcome Summary

Customer Focus	• Improve reliability for customers by reducing the number of interruptions due to cross arm equipment failures. • Meet customer service obligations by replacing or removing sentinel lights.
Operational Effectiveness	• Maintain the safe, reliable, and efficient operation of the distribution system through proactive replacement of deteriorated, obsolete, and substandard equipment, including devices that support outage response and system visibility
Public Policy Responsiveness	• Relocate bird nests on distribution poles in accordance with applicable regulatory obligations, including under the *Migratory Birds Convention Act, 1994*.

4.0 EXPENDITURE PLAN

Expenditures for this program have been forecast for the planning period based on historical costs and either the planned units of work (in the case of cross arms, substandard transformers and CFCIs) or projected volume based on trends over time (in the case of bird nests and sentinel lights).

Tables 7, 9, and 10 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 planning period and forecast net capital expenditures for the 2028-2032 planning period, with a breakdown by activity included in Table 8.

Table 7 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	66.0	43.6	31.5	28.5	29.1	29.9	30.5	149.6
Less Removals	6.9	5.2	3.8	3.4	3.5	3.6	3.6	17.8
Less Capital Contributions	0.0	0.0	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0
Net Capital Expenditures	**59.1**	**38.4**	**27.8**	**25.1**	**25.6**	**26.4**	**26.9**	**131.7**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Table 8 - Hydro One - Investment Expenditures by Activity

Activity	2028-2032 Net Expenditures ($M)
Cross Arms	49.2
Nest Platforms	2.2
Transformers	54.7
Sentinel Lights	8.8
CFCI Replacement	16.8
Net Capital Expenditures	**131.7**

Table 9 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	0.02	0.09	0.09	0.09	Embedded in Hydro One Networks		
Less Removals		0.00	0.02	0.02	0.02			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.01**	**0.07**	**0.07**	**0.08**			

Table 10 - Peterborough RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	0.06	0.08	0.08	0.09	Embedded in Hydro One Networks		
Less Removals		0.01	0.01	0.02	0.02			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.05**	**0.07**	**0.07**	**0.07**			

2023-2027 EXPENDITURES

Over the 2023-2027 planning period, Hydro One forecasts expenditure for this investment to be $38.4M. The forecast 2023-2027 expenditure of $38.4M results in an underspend of approximately $20.7M. Table 11 shows the 2023-2027 planned versus forecast spend for each activity under the investment.

Table 11 - 2023-2027 Plan Versus Forecast Expenditure by Activity[4]

($M)	2023-2027 Plan	2023-2027 Forecast
Cross Arms	22.8	18.1
Nest Platforms	1.1	0.8
Sentinel Lights	11.2	14.0
Transformers	24.1	5.5
Total	**59.1**	**38.4**

The majority of the $20.7M variance relates to lower-than-planned volumes for cross arm and substandard transformer replacements. During the 2023-2027 period, Hydro One prioritized other non-discretionary investments presenting a higher immediate compliance, reliability or operational need. As a result, a portion of the planned work was deferred into the 2028-2032 period rather than completed. The underlying condition, reliability, and operational risks associated with these assets remain and are reflected in the proposed replacement volumes for the 2028-2032 planning period.

The variance was partially offset by higher-than-planned expenditures for sentinel lights resulting from a targeted initiative to proactively replace units with elevated PCB-related risk.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are $131.7M. The factors influencing the cost of the investments include:

- Cross Arms: Expenditures increase primarily due to higher planned replacement volumes required to address an existing inventory of poor condition cross arms, forecast future deterioration, and work deferred from the 2023-2027 period. The investment prioritizes higher-consequence locations where failure would impact larger numbers of customers, resulting in higher average replacement costs than historical levels.
- Substandard Transformers: Expenditures increase due to a combination of reprioritized work from the 2023-2027 period and a higher planned replacement volume. Costs remain highly variable because many installations are located in

[4] Figures presented in the tables may not sum to the totals shown due to rounding.

constrained environments, require customized engineering solutions, or cannot be replaced on a like-for-like basis.

- CFCIs: The 2028-2032 period includes Hydro One's first large-scale replacement cycle for this asset class. Approximately 3,350 devices are being replaced due to age or defective condition, while approximately 1,000 devices require replacement because the communication technology will become obsolete following the retirement of 3G cellular networks. Expenditures are primarily volume-driven and reflect the expected lifecycle replacement requirements of the installed population.
- Nest Platforms: Expenditures are driven by both the number of nest hazards identified through inspections and the site-specific remediation required. Forecast volumes have increased relative to prior planning assumptions based on recent experience, which showed a higher number of nest hazards requiring intervention than originally anticipated.
- Sentinel Lights: Expenditures are based on historical replacement and removal volumes associated with Hydro One's ongoing contractual obligations to existing sentinel light customers and are generally consistent with historical program requirements.

5.0 ALTERNATIVES

Hydro One considered the following 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, substandard transformers, and CFCI devices.

ALTERNATIVE 1: REACTIVE REPLACEMENT

This alternative was considered and rejected for cross arms, substandard transformers, and CFCI devices 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. In the case of CFCI devices, replacing devices only at the time of failure

would increase labour costs associated with line patrol, as lines staff would need to patrol longer sections of feeder, increasing the outage duration for distribution customers. This approach would also result in increases to SAIDI, a key metric for distribution system reliability.

ALTERNATIVE 2: ACCELERATED PLANNED COMPONENT REPLACEMENT

This alternative was considered and rejected for cross arms, as the benefit of the additional investment would be low relative to the cost and the number of customers impacted. The investment already includes the entire population of substandard transformers due to their reliability and safety risk and the higher efficiency of replacement under a planned program compared to reactive work. An accelerated plan for CFCIs would entail replacing units before their end of life, which would result in underutilization of the assets.

ALTERNATIVE 3: PLANNED COMPONENT REPLACEMENT (RECOMMENDED)

This alternative is recommended as it addresses high-priority operational risks related to cross arms, substandard transformers, and CFCI devices. 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 mitigates operational and safety risks while being more efficient and cost-effective than reactive replacement. In the case of CFCI devices, proper management of a replacement program provides a more cost-effective solution, as multiple units within close geographic proximity can be targeted together to achieve better efficiency. Units are prioritized based on their condition, age, system impact, and geographic location.

This alternative balances reliability improvement, safety and compliance requirements, and affordability by targeting only those assets that present the highest operational and customer service risks while maximizing the useful life of remaining assets.

6.0 EXECUTION RISK AND MITIGATION

The primary execution risk relates to substandard transformer replacements, which often involve the replacement of transformers in higher-density areas and may lead to design complexities. This risk is mitigated by identifying particularly complex units as part of the

detailed design process and planning accordingly, taking into account site-specific challenges and the associated impact on scheduling.

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D-SR-09	**SUBMARINE CABLE REPLACEMENT PROGRAM**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	23.6	24.4	27.8	25.0	25.5	126.3
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

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 caused by defective submarine cable.

There are no planned or forecast capital expenditures for Orillia Rate Zone (RZ) or Peterborough RZ.

1.0 INVESTMENT NEED

Hydro One's distribution system contains approximately 14,000 submarine cable installations, covering approximately 4,100 circuit km. Submarine cables are necessary to supply island dwellings and to substitute for overhead water crossings that are not technically or economically feasible. Submarine cables are especially prone to damage and corrosion where they are required to enter water at the shoreline. 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 of year-end 2025, approximately 1,350 (10% of total population) cables have been identified in poor condition through ongoing, cyclical submarine cable patrols as seen in Figure 1 below.

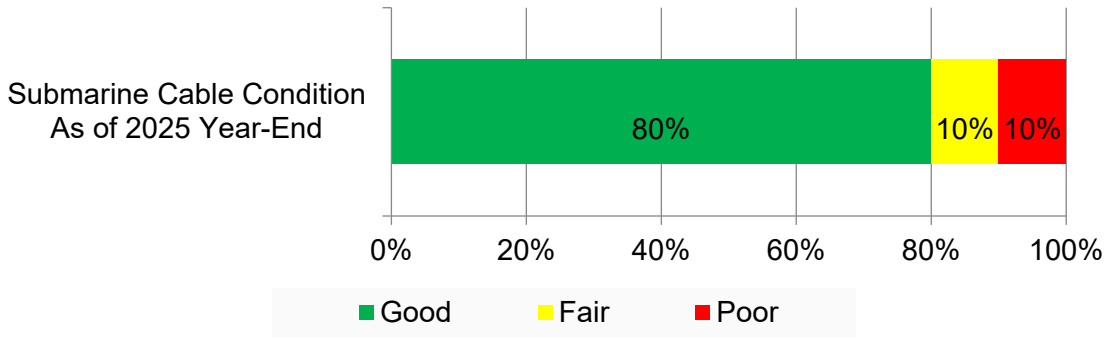


Figure 1: Submarine Cable Condition as of 2025 Year-End

Of these poor condition cables, approximately 750 cables are damaged and 600 cables are exposed at the shoreline. As observed in Figure 2, damaged cables usually exhibit abrasion or corrosion of the protective cable armour which can lead to neutral failure or water ingress. Damaged cables can pose public safety hazards and increase reliability risks. Exposed cables are not necessarily damaged but are subject to increased environmental risks and are more likely to become damaged over time.

While both damaged and exposed cables require intervention, damaged cables represent the highest risk category, as armour degradation can result in neutral failure, water ingress, and elevated public safety concerns. However, exposed cables are vulnerable to

accelerated environmental degradation, increasing the likelihood of future safety and reliability issues.

Generally, under this investment, damaged cables are replaced and exposed cables are refurbished via mechanical shoreline protection. Cables that present an immediate safety risk (i.e. more than 75% of the neutral cross section is missing or broken or an approved temporary repair is older than the allowed duration) are addressed through the Distribution Lines Trouble Call and Storm Damage Response Program investment (the "Trouble Program" – see DSP Section 3.11, D-SR-05). Submarine cables meeting these criteria are considered emergent candidates because the public safety and reliability risks require immediate corrective action and cannot be deferred to a planned replacement or refurbishment cycle.



Figure 2: Example of (left) an Exposed Cable Showing Initial Signs of Corrosion, and (Right) a Corroded Cable with Significant Damage

Hydro One proposes to increase submarine cable investment during the 2028-2032 rate period to address damaged and exposed cables on a planned cycle. This increased investment is necessary because much of the submarine cable work planned for the 2023-2027 rate period was reprioritized, resulting in reduced spending and accomplishments compared to plan. The company made this decision as part of its reprioritization effort to accommodate higher than forecasted non-discretionary demand and unplanned scope across the distribution investment portfolio, as further discussed in *Section 4 – Expenditure Plan*. This deferral has led to continued cable deterioration and worsening

cable condition. To keep pace with the deferred units from 2023-2027, additional units have been added from 2028-2032.

The population of submarine cables within the Hydro One distribution system continues to deteriorate. For example, of the submarine cables inspected in 2018 and again in 2024, 32% of them deteriorated further in terms of corrosion and 'percent armour missing' values. Approximately 15% of the submarine cables went from "good" (0% armour missing) condition to "fair" (1% to 24% armour missing) or "poor" (25% or more armour missing) condition. In terms of corrosion, of the submarine cables that showed no signs of corrosion in 2018, approximately 25% of them began showing signs of light corrosion in 2024.

The scale of this inventory of poor-condition submarine cables, coupled with incremental deterioration, underpins the urgency of the proposed investment. As of year-end 2025, approximately 1,350 cables were identified in poor condition, representing 10% of the total population. Without planned investment, these assets are expected to continue to deteriorate, increasing the number of cables requiring emergency intervention and elevating both public safety and reliability risks. The proposed investment therefore addresses both the existing inventory of poor-condition submarine cables and the new defects expected to emerge over the planning period.

In addition, as seen in Figure 3 below, emergent submarine cable replacements and temporary repairs completed through the Trouble Program (SR-05) increased by 157% relative to the 2018-2020 period. This increase is attributable to the reprioritization of planned work and resulting in the deterioration of damaged and exposed cables to the point where emergency intervention was required.

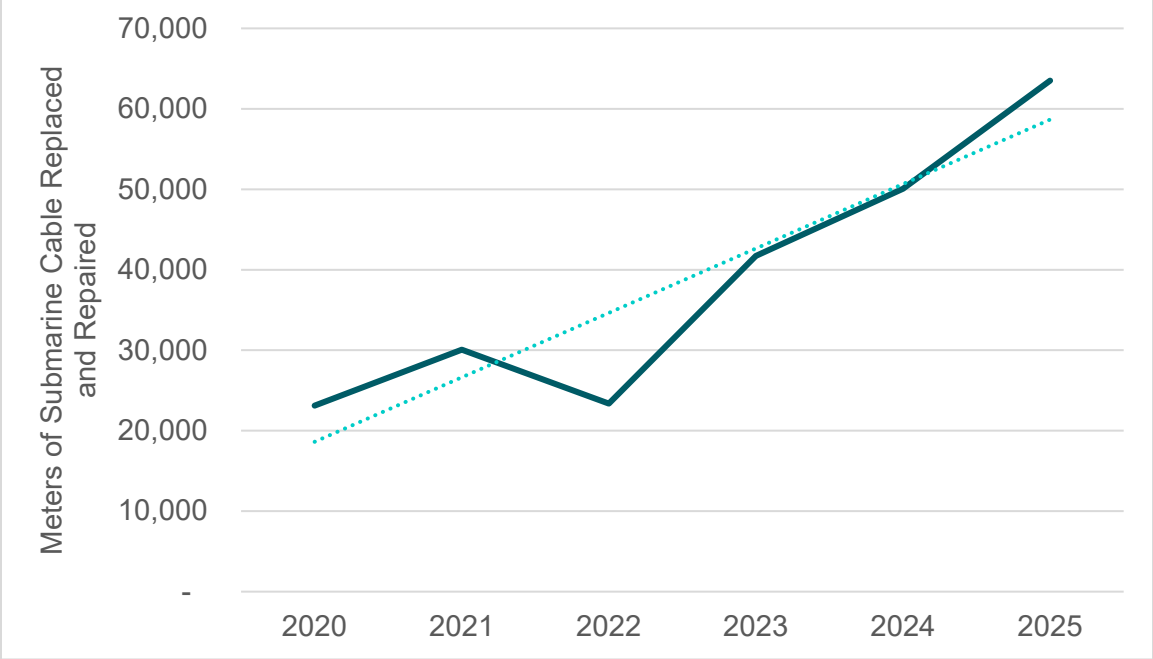


Figure 3: Meters of Submarine Cable Replaced under Trouble Program (SR-05)

The increase in emergent work demonstrates the consequences of deferring planned interventions. As submarine cables continue to deteriorate, reliance on reactive work grows, increasing operational complexity, extending customer outage durations, and representing a less efficient approach to managing safety and reliability risks. Planned replacement and refurbishment are therefore required to restore a planned cycle and reduce reliance on emergent corrective work. To this end, addressing defects before failure materially reduces customer impacts. Planned outages associated with submarine cable replacement and refurbishment average approximately 2.7 hours in duration, compared to 20.4 hours for unplanned outages resulting from cable failure. As a result, addressing defects before failure improves service reliability and mitigates operational risks.

2.0 INVESTMENT DESCRIPTION

Damaged and exposed cables are identified during regular inspections which occur on a six-year (rural) or three-year (urban) frequency. If an inspection identifies a submarine cable that poses an immediate safety hazard or as an emergent replacement or repair, it is addressed by the Trouble Program (see DSP Section 3.11, 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.

Damaged cables must be replaced (and cannot be refurbished) because refurbishment activities are insufficient to mitigate the operational and safety risks such cables present. 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. Submarine cables that no longer meet current distribution standards or have failed electrically due to insulation breakdown are always replaced.

An exposed cable that is not damaged can be addressed through refurbishment by installing mechanical protection. Depending on the nature of shoreline where the cable enters the water, several options are available to mechanically protect the cable, including installation of a duct or covering the cable with concrete. Cables are typically subject to the highest environmental degradation at the shoreline where they are accessible to the public. Therefore, cables are only mechanically protected where they are on land and where they enter the water at the shoreline.

This investment is expected to replace or refurbish all submarine cables with currently known ‘damaged or exposed’ defects and additional submarine cables that become damaged or exposed over the planning period. Replacing all damaged submarine cables and refurbishing exposed cables in this period in a planned manner best addresses public safety risk from damaged cables, as well as reduces customer interruption time during defect mitigation.

The proposed program aligns with Hydro One's condition-based asset management approach by targeting replacements and refurbishments where inspections identify damaged or exposed assets. This allows Hydro One to focus expenditures on assets presenting the greatest safety and reliability risks, while avoiding premature replacement of submarine cables that remain in acceptable condition.

3.0 OUTCOMES

The Submarine Cable Replacement program reduces public safety risk, prevents further asset deterioration, and reduces the likelihood of cable failures by addressing damaged cables on a planned basis. By correcting defects before failure occurs, the program helps maintain a planned replacement cycle and reduces reliance on emergency repairs. This investment is expected to keep pace with the renewal requirements of the cable population over time and minimize this risk.

The Submarine Cable Refurbishment program addresses exposed cables before significant deterioration occurs, extending asset life, reducing future replacement requirements, and mitigating the risk that exposed cables deteriorate into higher-risk damaged assets. This investment is expected to keep pace with the number of exposed cables being discovered on an ongoing basis.

3.1 OEB RRF OUTCOMES

The following table presents anticipated benefits of the investment in accordance with the 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. • Reduce customer outage duration by addressing defects through planned, proactive work rather than reactive repairs.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively replacing deteriorated equipment. • Reduce reliance on emergency corrective work.

4.0 EXPENDITURE PLAN

Table 2 below summarizes Hydro One's aggregate planned and forecast net capital expenditures for the 2023-2027 rate period and the forecast net capital expenditures for the 2028-2032 planning period. There are no planned, annual or forecasted net capital expenditures for Orillia RZ or Peterborough RZ.

Table 2 - Hydro One – Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	66.9	11.7	26.8	27.7	31.7	28.4	29.0	143.6
Less Removals	0.0	1.4	3.2	3.3	3.9	3.4	3.5	17.2
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**66.9**	**10.4**	**23.6**	**24.4**	**27.8**	**25.0**	**25.5**	**126.3**

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures to be $10.4M, which is below approved amounts primarily due to the reprioritization of planned funding from this program to address high-priority, non-discretionary work. On a volume basis, the program replaced 105 cables and refurbished 432 submarine cables over the 2023-2027 period, compared to a plan of 2,375 submarine cables. To continue mitigating the safety risk associated with defective submarine cables, Hydro One prioritized the replacement of severely degraded cables and increased corrective work on emergent candidates under the Trouble Program. In addition, supply chain constraints reduced program spending in the earlier years of the program, as cable manufacturers were unable to meet the forecasted demand, resulting in delayed material deliveries and limiting the amount of work that could be completed.

2028-2032 EXPENDITURES

Hydro One proposes $126.3M in submarine cable expenditures over 2028-2032, an increase from the current rate period driven by three factors: (i) the need to address the existing inventory of poor-condition cables, including those deferred from the 2023-2027 period; (ii) additional defects expected to be identified through ongoing patrol activities; and (iii) market-driven increases in materials and equipment costs, as noted in SPF Section 1.8, Managing Market Cost Pressures.

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

While 2,375 submarine cable replacements and refurbishments were planned during the 2023-2027 period, Hydro One forecasts completing only 537 interventions. As a result, approximately 1,800 planned replacements and refurbishments were deferred, contributing to the current inventory of poor-condition cables requiring corrective action.

Submarine cable replacements and refurbishments account for $103.1M and $23.2M, respectively, over the 2028-2032 planning period. From a unit perspective, Hydro One plans to replace approximately 1,720 submarine cables and refurbish approximately 1,530 submarine cables between 2028 and 2032. These volumes are based on both currently identified defects and forecasted future defects derived from historical inspection results.

Of this total, approximately 40% (1,350 cables) relates to defects already known as of 2025 year–end, and approximately 60% (1,900 cables) relates to future defects expected to be identified through ongoing patrol activities. Hydro One derived the forecast of future defects from historical inspection data. Between 2019 and 2025, cyclical patrols identified, on average, approximately 140 submarine cables annually requiring replacement and 134 requiring refurbishment. As the asset population ages and environmental degradation progresses, these cyclical patrols continue to identify additional damaged and exposed cables each year.

Accordingly, the proposed volume addresses not only currently known defects but also maintains pace with the rate at which additional damaged and exposed cables are expected to be identified through ongoing inspections.

Given the operational and safety risks associated with damaged and exposed submarine cables, the proposed plan is intended to address both the existing inventory of known defects and newly emerging defects before they require emergency intervention. This approach mitigates public safety risk, reduces customer impacts associated with unplanned outages, and helps avoid a continued shift from planned to reactive work.

Without the proposed investment increase, Hydro One would be unable to address the existing inventory of poor-condition cables while keeping pace with newly identified

defects, resulting in a continued increase in emergency work and associated customer impacts.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: REACTIVE SUBMARINE CABLE REPLACEMENT

Under this alternative submarine cables would be allowed to deteriorate to the point of becoming emergent candidates posing an immediate safety risk and corrected under the Trouble Program. This alternative was rejected because it would increase public safety exposure, increase the likelihood of unplanned customer interruptions, and allow additional asset deterioration before corrective action is taken. As demonstrated by the increase in emergent submarine cable repairs under the Trouble Program, reliance on reactive intervention is a less efficient and less effective method of managing submarine cable risk.

ALTERNATIVE 2: 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.

ALTERNATIVE 3: PLANNED REPLACEMENT OR REFURBISHMENT OF KNOWN DAMAGED OR EXPOSED SUBMARINE CABLES (RECOMMENDED)

The recommended alternative represents a targeted, condition-based asset management approach that prioritizes intervention on assets presenting the greatest safety and reliability risks while avoiding premature replacement of submarine cables that remain in acceptable condition. The proposed volumes are sufficient to address both the current inventory of poor-condition cables and the defects expected to emerge through ongoing inspection activities over the planning period.

This approach mitigates the safety risks associated with these cables while maintaining a relatively stable investment level. Any emergency repairs will continue to be managed under the Trouble Program.

6.0 EXECUTION RISK AND MITIGATION

Submarine cable replacement requires specialized equipment and unimpeded cable access. Cables cannot typically be replaced during the winter season. To mitigate this risk, the investment is scheduled from early spring to late fall to avoid frozen conditions.

Supply chain constraints or disruptions, including capacity constraints, production issues, and delays in material deliveries, may affect the ability to execute the program. To mitigate this risk, Hydro One will provide suppliers with multi-year demand forecasts, actively monitor supplier performance, and work closely with suppliers to ensure adequate inventory levels and address shortages proactively.

In addition, skilled resources and specialized equipment are required to complete the work. Considering the planned additional units for the 2028 to 2032 period, Hydro One will mitigate resource constraints by hiring qualified vendors on an as needed basis to execute work in addition to internal staff and procure additional equipment to keep pace with planned work, as necessary.

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D-SR-10	DISTRIBUTION LINES SUSTAINMENT INITIATIVES
Primary Trigger:	Asset Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	9.3	28.1	105.5	48.8	17.2	209.0
Orillia RZ	0.06	0.07	0.07	Embedded in Hydro One Networks		
Peterborough RZ	0.03	0.03	0.03			

Summary:

Distribution Line Sustainment Initiatives primarily address overhead feeder sections that are located off-road and contain a large proportion of end of life assets based on their condition. The primary investment trigger is asset condition. These investments rebuild deteriorated off-road feeder sections along roadside, reducing future restoration times and improving access for inspection, maintenance and outage response.

1.0 INVESTMENT NEED

Hydro One's distribution system consists of approximately 126,000 circuit km 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 equipment, such as overhead transformers, switches, reclosers, voltage regulators, and capacitor banks.

Distribution Lines Sustainment Initiatives address overhead feeder sections, focusing on off-road sections that require rebuilding because they contain a large proportion of end of life assets based on their condition. These rebuilds usually involve relocating the entire feeder section, including poles, conductor, and hardware, from off-road locations to roadside, with accompanying reliability and operational benefits.

As outlined in DSP Section 3.2, subsection 3.2.1.1, Hydro One assesses the condition of its distribution assets, including the components that comprise its distribution feeders through a combination of visual inspection and quantitative testing. 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 increased risk of failure.

The investments in this Investment Summary Document (ISD) primarily address feeder sections requiring an integrated rebuild of poles, conductor, hardware and any equipment on the associated pole. Distribution Lines Sustainment Initiatives also includes locations where pole replacement cannot be completed without replacing conductor, or where non-standard pole framing or other line-specific requirements require unique engineering and construction techniques. This scope is distinct from Pole Sustainment Program (DSP Section 3.11, D-SR-07), which focuses on proactively replacing individual or clusters of poles and associated hardware in place, while retaining the existing conductors and equipment.

Replacing poor condition poles reduces reliability risk and mitigates customer outages associated with pole failures. As discussed in DSP Section 3.2, subsection 3.2.1.3, Pole

Asset Performance, pole-related reliability performance worsened as the pole population has aged and the number of poor condition poles has increased. Comparing the 2021-2025 period with 2016-2020, average annual pole-related interruptions increased from 290 to 495, or approximately 70%, while average annual pole-related SAIDI increased from 0.21 to 0.35 hours. Figure 1 below illustrates the historical pole-related contributions to SAIDI.

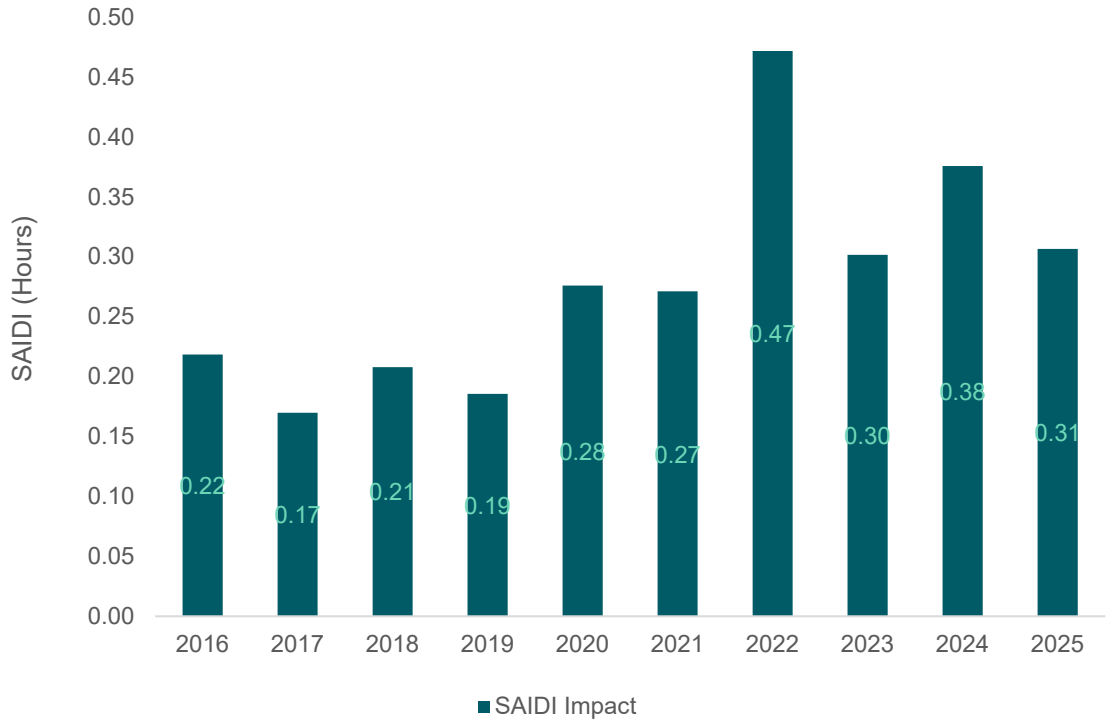


Figure 1: Pole Caused SAIDI (excluding FM)

For poor condition assets located off-road, the reliability consequences of a failure are compounded by the additional time and effort required to access the line to restore service. In general, when off-road distribution lines fail, replacing the affected equipment takes substantially longer than replacing a similar asset located roadside. 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 increases the time and effort required to restore affected customers.

Across Hydro One's distribution system, and as shown in Figures 2 and 3, feeder performance varies significantly between feeders with a significant proportion of off-road sections and those that are substantially on-road. Specifically, as illustrated in Figure 2, feeders with more off-road poles typically experience longer outage duration than on-road feeders. Furthermore, as illustrated by the FAIFI performance presented in in Figure 3, the number of outages on feeders with significant off-road sections is also higher than on-road feeders. Together, these results demonstrate that customers supplied from feeders with significant off-road sections experience worse reliability than customers supplied from primarily on-road feeders. Hydro One has more than 400 feeders with a significant proportion of off-road sections.

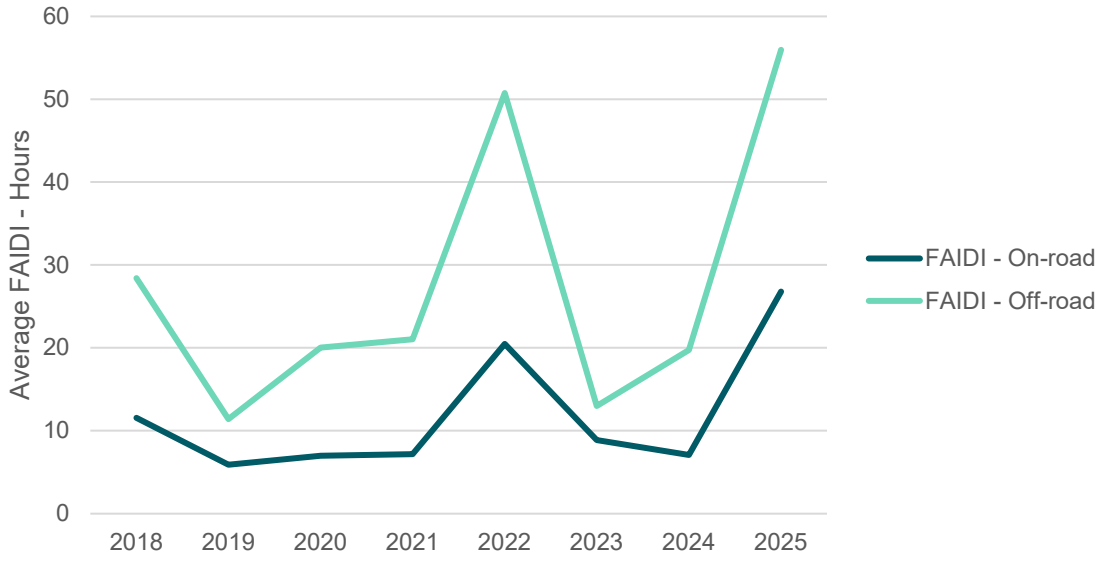


Figure 2: On-Road vs. Off-Road FAIDI

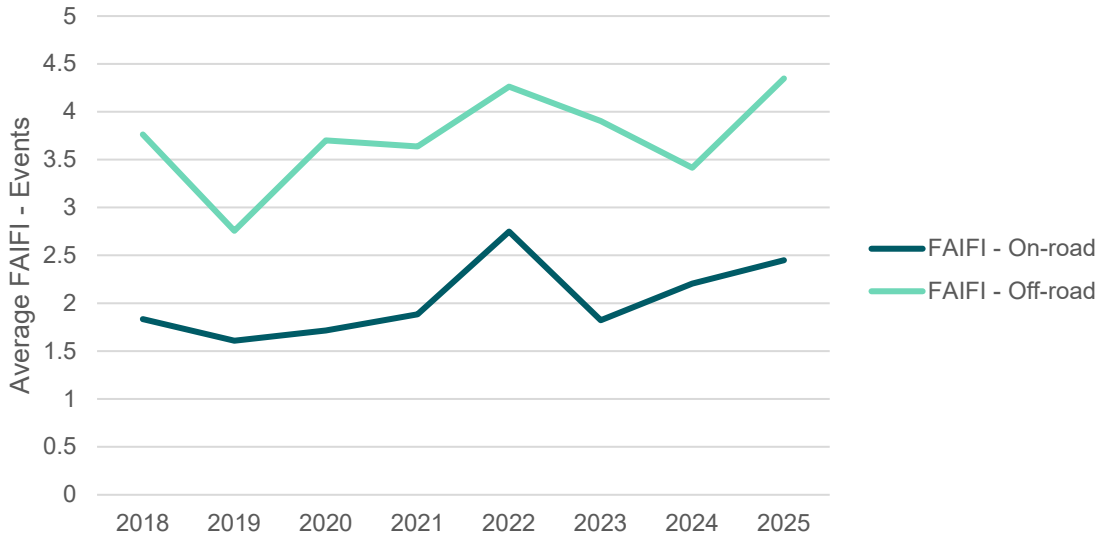


Figure 3: On-Road vs. Off-Road FAIFI

Figure 4 below illustrates an example of some of the challenges with off-road distribution lines. The picture shows the Ingersoll TS M44 and M46 feeders as they cross a customer's quarry off-road. The distribution lines on wooden poles run adjacent to the large transmission structures and are outlined in black rectangles. Since these poles are at the top of an approximately 300-foot cliff, replacement would require restringing conductor between the poles by helicopter and other special tools that Hydro One distribution lines staff do not typically utilize, significantly increasing the complexity and expected duration of restoration work.

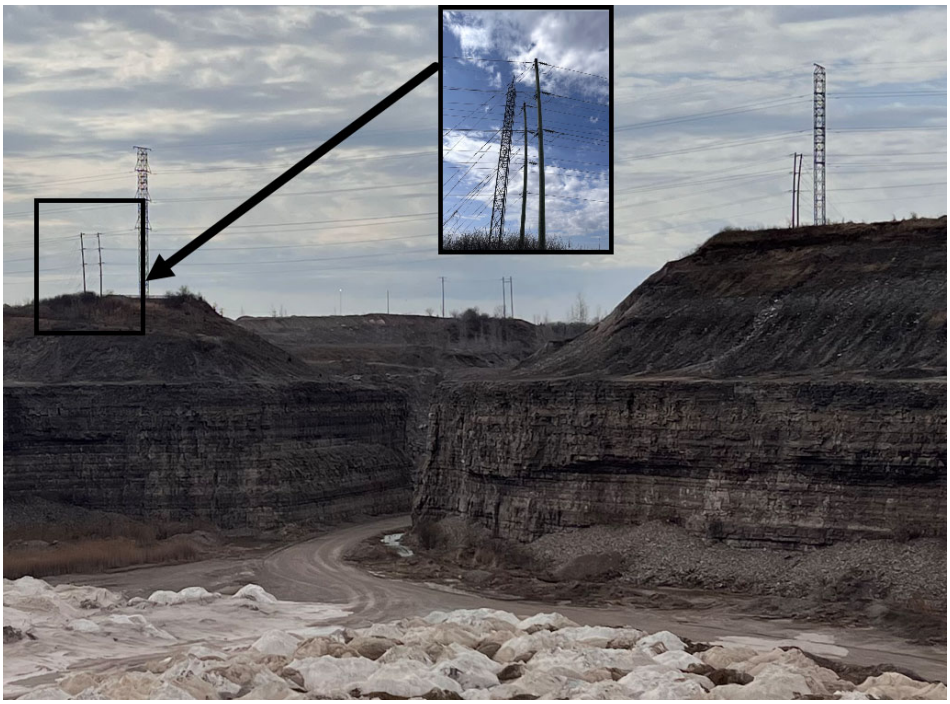


Figure 4: Off-Road Distribution Line Crossing a Customer's Quarry

When end of life poles located off-road fail, outages can take significantly longer to restore. Off-road feeder sections can experience 2.3 times the average outage length compared to feeder sections that are roadside. Relocating off-road end of life poles and equipment to a suitable road allowance reduces the accessibility constraint and is expected to shorten the restoration activities for future outages on these sections.

2.0 INVESTMENT DESCRIPTION

Distribution Line Sustainment Initiatives address overhead feeder sections in an integrated manner by addressing line equipment that is in poor condition and where failure would adversely impact customer reliability. Feeder sections are identified and prioritized for inclusion in this investment over the plan period based on associated consequences in the event of failure, off-road pole concentration, pole condition, and operational feedback.

Rebuilding a feeder section is preferred when the end of life feeder sections are located off-road, creating logistical and operational barriers to timely restoration following an outage. Rebuild investments are also necessary where the conductor supported by a poor

condition pole is itself deteriorated and cannot be safely or reliably reused. Removing and reinstalling deteriorated conductor during individual pole replacements can result in conductor failure due to reduced shear strength. Such a failure can increase the scope of the work, extend the planned outage, and require additional pole replacements to support the new conductor installed in accordance with Ontario Regulation 22/04 requirements and current standards. An integrated rebuild avoids these risks and is expected to reduce outage impact to customers affected by failure of off-road poles.

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. Specifically, design, engineering, and procurement activities involve:

- Determining preliminary pole locations, and pole sizes
- Determining appropriate conductor size and equipment requirements
- Negotiating and obtaining property access with the relevant landowner, which for roadside construction is typically a road authority
- Finalizing design based on negotiated pole locations and executed property access agreements
- Ordering materials, specifically, poles, conductor, hardware and equipment

Once design, engineering and procurement activities are complete, construction begins which involves:

- Installing new poles with appropriate conductor support hardware installed
- Stringing new conductor
- Installing any required equipment on the newly set poles
- Energizing the new lines and equipment by connecting the newly installed conductors to the existing lines

The Distribution Lines Sustainment Initiatives address feeder sections that have a large number of poor condition primarily off-road assets in close proximity. This eliminates the need to mobilize crews multiple times to address different feeder components on the same feeder 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.

Based on the inspection and testing of overhead feeders, in particular the wood pole support structure, Hydro One has identified more than 250 km of distribution line sections that have a high concentration of off-road poor condition wood poles. In order to relocate these lines to the road allowance, a further 150 km of distribution line will be rebuilt to support the relocated distribution line sections. These relocation and rebuilding activities will result in the replacement of more than 1,500 poor condition poles. By replacing the poor condition assets and relocating the distribution lines sections to road allowance, Hydro One expects to reduce the risk of failure on these feeders and reduce outage restoration times in the event of an outage in the future.

Recent reliability trends have been notably poor for customers supplied from the feeders identified under this investment. Specifically, these customers have seen worse reliability than customers supplied from other feeders. As a result of the proposed Distribution Line Sustainment Investments, the affected feeders, some of which serve up to 10,000 customers, are expected to experience improved reliability through the replacement of deteriorated assets and improved restoration access.

This ISD includes 31 material projects (net capital investment exceeding $1M), as detailed individually in Appendix A. In addition, this ISD includes immaterial investments, which are discussed in aggregate for each of the Hydro One, Orillia and Peterborough rate zones (RZ). These immaterial projects are Distribution Line Sustainment Initiatives with net capital expenditures less than $400k, and are typically engineered and constructed in a single year.

Example Investment: Norfolk Feeder Relocation

Planned Distribution Lines Sustainment work on the Norfolk Transformer Station (TS) M3 feeder illustrates the need, nature, and expected customer outcome of the work carried out under this ISD.

The Norfolk Transformer Station (TS) M3 feeder is a 27.6kV distribution line serving more than 4,000 customers in Norfolk County. Communities served by this feeder include Simcoe, Vittoria, and St. Williams. This feeder has an off-road section which is 14 km long, running between Vittoria and St. Williams, with a high concentration of end of life wooden poles. As the condition of the assets has deteriorated, customers served by the feeder have experienced average annual Customer Minutes of Interruption of 5.5 million and have seen a 152% degradation in performance in their annual feeder reliability since 2018. Figure 5 below shows the annual CMI experienced by customers supplied from this feeder since 2018.

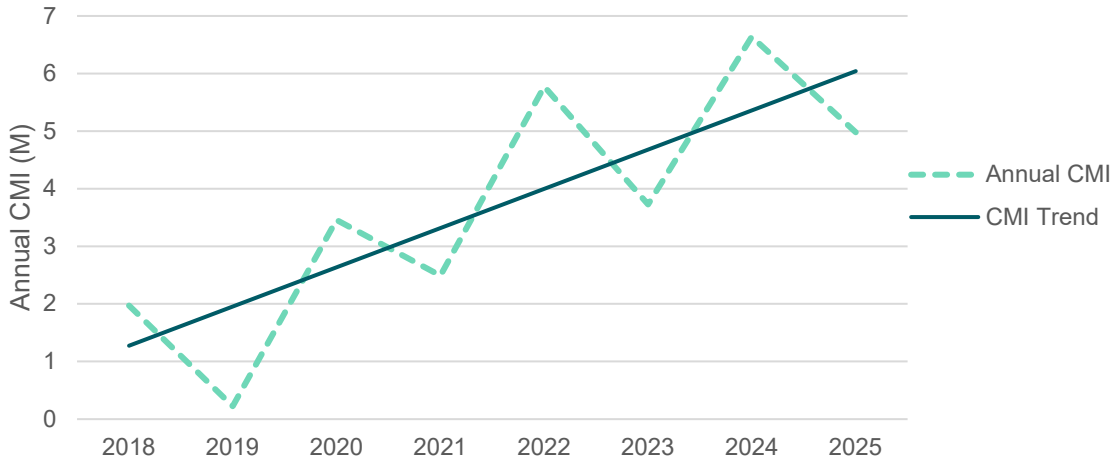


Figure 5: Annual Customer Minutes of Interruption experienced by Customers on the Norfolk TS M3 feeder

Furthermore, through Hydro One's inspection and testing programs, Hydro One has identified 96 poor condition poles on the off-road section of the Norfolk TS M3, and 47 poor condition poles along road allowance, which need to be replaced before they fail and reduce feeder reliability further. Figure 6 shows the Norfolk TS M3 feeder (left) heading off-road towards the tree line, and the road-side feeder (right) is where the Norfolk TS M3 feeder is planned to be relocated under this investment.



Figure 6: Imagery of the off-Road Norfolk TS M3 Feeder Crossing CharlotteVille Rd 1 in Norfolk County

The off-road configuration of the 14 km Norfolk TS M3 feeder section makes restoration slow and complex. Historically, it has taken Hydro One more than 12 hours on average to make repairs in the off-road section, primarily because of the time required for line patrols to identify the defect and the complexity of bringing in equipment and materials necessary to make repairs. With the exception of a small number of poles which can be inspected/repaired near road crossings, both line patrols and repair activities require specialized vehicles. This complicates and delays restoration activities.

By rebuilding the off-road Norfolk TS M3 feeder section along the roadway, Hydro One expects that average outage times would be brought below four hours, as standard on-road vehicles and equipment can be used both for patrol and repair. In addition, the frequency of outages would be reduced through the replacement of deteriorated equipment with assets that meet current standards.

The Norfolk TS M3 relocation work will be completed in three stages beginning with design work in 2029, with the on-road relocation and off-road removal work being completed for

all stages by 2032. Figure 7 illustrates the location of the existing Norfolk TS M3 feeder, as well as the revised routing for the new proposed relocated feeder.

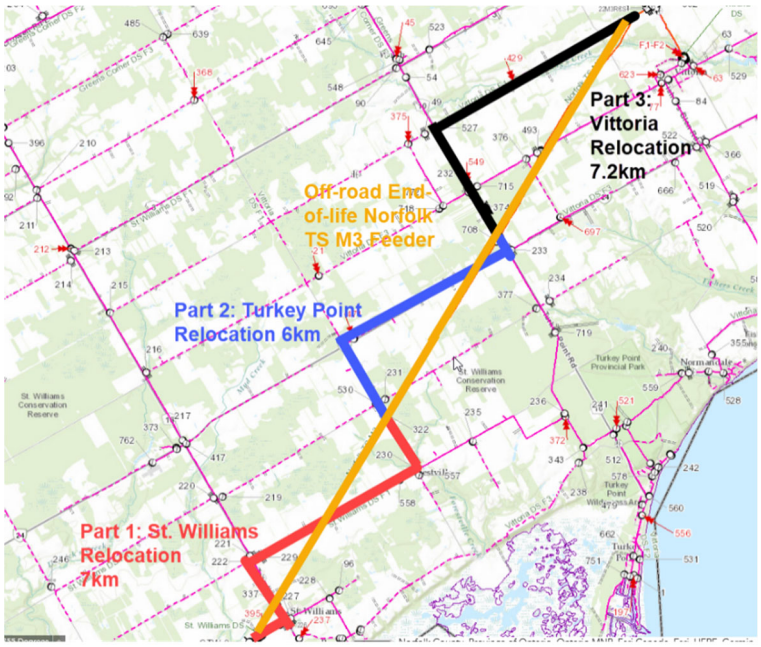


Figure 7: Existing Off-road and Planned On-road Routing of the Norfolk TS M3 feeder

Hydro One estimates the annual average outage savings as a result of this investment to exceed 4 million CMI, or a greater than 70% reduction in the Feeder Average Interruption Duration Index (FAIDI).

3.0 OUTCOMES

Distribution Line Sustainment Initiatives will:

- Rebuild distribution line sections with end of life poles and, for identified off-road projects, relocate the affected sections to roadside;
- Improve reliability on the affected off-road feeder sections, and maintain reliability on on-road feeder sections

3.1 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 accessibility and reliability by reducing the outage impact to customers. • Maintain safe and reliable operation of the distribution system by proactively addressing line equipment in an integrated manner.

4.0 EXPENDITURE PLAN

Table 2, 3, and 4 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	128.8	117.7	10.6	31.8	119.9	55.5	19.6	237.2
Less Removals	15.4	13.6	1.3	3.7	14.4	6.6	2.3	28.3
Less Capital Contributions	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**113.4**	**103.8**	**9.3**	**28.1**	**105.5**	**48.8**	**17.2**	**209.0**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Table 3 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	-	0.18	0.07	0.07	0.07	Embedded in Hydro One Networks		
Less Removals		0.02	0.01	0.01	0.01			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.17**	**0.06**	**0.07**	**0.07**			

Table 4 - Peterborough RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	-	0.76	0.09	0.09	0.09	Embedded in Hydro One Networks		
Less Removals		0.19	0.06	0.06	0.06			
Less Capital Contributions		0.01	0.00	0.00	0.00			
Net Capital Expenditures		**0.55**	**0.03**	**0.03**	**0.03**			

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, planned expenditures for Distribution Lines Sustainment Initiatives were $113.4M, compared to actual/bridge/forecast expenditures of $103.8M at the time of filing, resulting in expenditures being $9.6M, or 8%, below plan.

Over the 2023-2027 rate period, Hydro One forecasts expenditures for material Distribution Line Sustainment Initiatives to be $80.2M, compared to planned expenditures for material investments of $62.7M, resulting in an increase of $17.5M or 28%. On a volume basis, Hydro One forecasts that it will deliver 10 material line sustainment investments over the 2023-2027 period, compared with 21 material line sustainment investments included in the plan. Although fewer material investments were undertaken, forecast expenditures are higher than planned because of changes in work volumes and timing.

Relative to the original plan, Hydro One deferred most line relocations due to capital constraints associated with increased non-discretionary work expenditure. Seven material Distribution Line Sustainment investments proceeded, and Hydro One advanced three feeder relocations involving idle transmission lines rented from Hydro One Transmission. Hydro One Distribution has been asked to vacate these transmission lines, requiring the establishment of new distribution lines. These three investments represent more than 40% of total material Distribution Line Sustainment expenditures over the 2023-2027 rate period. These changes explain the difference between planned and actual material investment expenditures and delivered volumes.

The overall program variance also reflects lower cable injection expenditures. The Distribution Line Sustainment program included planned cable injection expenditures of $13.9M over the 2023-2027 rate period, compared to actual/bridge/forecast expenditures of $5.9M, resulting in a variance of $8.0M, or 58%. This variance was driven by reprioritization of the program in response to other system needs. Starting in 2028, the cable injection program will be completed under DSP Section 3.11, D-SR-15, Underground Cable Replacement Program.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are $209M.

The forecast for material Distribution Line Sustainment Initiatives, which represent approximately 80% of the expenditure in this program, is based on recent-historical estimated project costs, and the volume of work identified over the forecast period. For each identified Distribution Line Sustainment Initiative, the length of the new route for the new distribution lines has been determined, and historical dollars per kilometer unit prices were applied to estimate the cost per project.

The forecast for immaterial Distribution Line Sustainment Initiatives, which represent approximately 20% of the expenditure in this program, is based on historical average work volumes and expenditures for the same type of work. Over the 2028-2032 planning period, the forecast based on historical volumes is to relocate more than 60 km of off-road distribution line to road allowance associated with immaterial Distribution Line

Sustainment Initiatives. These immaterial projects are smaller line rebuild or relocation investments with net CAPEX less than $400k, which are typically engineered and constructed in a single year.

Hydro One expects design work for the Distribution Line Sustainment Initiatives identified in Appendix A to begin in 2028, with significant ramp-up of design activities in 2029 to make way for majority construction activities in 2030 and 2031.

In order to relocate 250 km of off-road distribution line sections, and to rebuild existing poor condition lines on road that meet the eligibility criteria of Distribution Line Sustainment Initiatives as discussed in Section 1, Hydro One will construct more than 400 km of distribution line during the 2028 to 2032 planning period, including rebuilds. A detailed breakdown of material investments is in Appendices for Hydro One. There are no material investments identified in the Orillia RZ and Peterborough RZ, and the associated expenditure tables are in appendices B and C, respectively.

From a pacing perspective, through Distribution Line Sustainment Initiatives over the 2028-2032 planning period, Hydro One is proposing to address a subset of Hydro One's feeders with a large concentration of off-road poles. In particular, Hydro One plans to address only the most impactive off-road sections on approximately 10% of 400 feeders with significant off-road sections, where those feeders:

- Have experienced significant reliability deterioration since 2021, and
- Have a high concentration of off-road, end of life poles, and
- Have municipal right-of-ways located in close proximity to the off-road line.

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 and along the newly proposed feeder route;
- 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 requirement for equipment on the new poles, such as switches, capacitor banks, voltage regulators, and reclosers;
- Property access (i.e. easement) costs; and
- Other requirements from the road authority or property owner at the new location.

5.0 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 it fails. This alternative is rejected for investments included in this ISD as emergency replacements for these feeder segments (i) typically lead to prolonged outages for off-road feeder sections, (ii) may be more costly as resources may be required outside of normal working hours, and (iii) reactive management of the distribution line equipment will lead to increased failures, resulting in degradation of reliability for Hydro One's customers. For off-road sections, replacing failed assets in place would also retain the existing access constraints and associated longer restoration times.

ALTERNATIVE 2: PROACTIVE REPLACEMENT OF INDIVIDUAL COMPONENTS

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, for the feeder sections addressed through this ISD, a significant proportion of deteriorated assets may require rebuild of the broader feeder section. Additionally, for off-road sections, component replacement in place would retain the existing access constraints and associated restoration times. As such, this alternative does not provide reduced outage duration associated with relocating off-road poles to road allowance.

ALTERNATIVE 3: DISTRIBUTION LINES SUSTAINMENT INITIATIVES (RECOMMENDED)

This alternative involves the planned rebuilding of feeder sections and relocation of off-road sections to roadside, where the components of the distribution line section have been identified as being in poor condition. This alternative also includes in-place rebuilds when conductor is end of life or an engineered solution is required. 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 feeders.

6.0 EXECUTION RISK AND MITIGATION

The primary risks that impact the completion of these investments include:

- Seasonal access limitations to install new equipment and remove old equipment
- System outage availability to minimize outage impact to affected customers while connecting new equipment and removing old equipment
- Temporary (i.e., laydown during construction) and permanent (i.e., easement) property utilization assurance from affected property owners
- Access to special vehicles (i.e. helicopter, off-road vehicles, etc.) to complete work per schedule

These risks are mitigated per Table 5:

Table 5 - Risk Mitigation

Execution Risk	Risk Mitigation
Seasonal Access Limitations	Detailed post-engineering work planning that aligns resource allocation with optimal construction start and end dates.
System Outage Availability	Scheduling required outages during work plan development to minimize the potential for outage cancellations after construction has commenced.
Temporary/permanent property access	Property access agreements are negotiated during the detailed engineering stage of the project, minimizing the risk of inability to access.
Access to special vehicles	Special vehicles are scheduled during development of the detailed work plan.

APPENDIX A - HYDRO ONE DESCRIPTION OF INVESTMENTS

Project Name	ID#	Project Description	Net Capital Investment ($M)				
			2028	2029	2030	2031	2032
A9K Refurbishment - Distribution Circuit Transfer	D-SR-10.1	7.2 km Relocation from Off-road to On-road	0.0	2.4	1.5	0.0	0.0
Armitage TS M31 Line Relocation	D-SR-10.2	11 km Relocation from Off-road to On-road	0.0	1.3	4.9	6.8	0.0
Belleville TS M6 Relocate-Reconductor	D-SR-10.3	3.5 km Relocation from Off-road to On-road	0.0	0.2	1.9	0.0	0.0
Dobbin TS M6 Relocation-Ackinson Rd	D-SR-10.4	1.2 km Relocation from Off-road to On-road	0.0	0.2	1.7	0.0	0.0
Duart TS M6 Relocation	D-SR-10.5	26 km Relocation from Off-road to On-road	0.0	0.2	7.3	0.0	0.0
Havelock TS M6 - Unimin Sustainment	D-SR-10.6	5.5 km Relocation from Off-road to On-road	0.0	0.5	4.3	0.0	0.0
Ingersoll M44/M46 Rebuild	D-SR-10.7	2.3 km Relocation from Off-road to On-road	0.0	0.9	4.1	4.1	0.0
Keith M3/M4 Rivercrossing Rebuild	D-SR-10.8	1.5 km River Crossing Rebuild	0.0	0.5	1.9	0.0	0.0
Kent TS M16 Relocation	D-SR-10.9	20 km Relocation from Off-road to On-road	0.0	3.3	8.1	0.0	0.0
Longueuil M23 off road relocation	D-SR-10.10	2.8 km Relocation from Off-road to On-road	0.0	0.1	1.3	0.0	0.0
Martindale TS – M6 & M7 Relocation	D-SR-10.11	22 km Relocation from Off-road to On-road	0.0	0.5	5.3	5.5	0.0
Meaford TS M1 Refurbishment – Lower Valley Road	D-SR-10.12	1.5 km Rebuild On-road	0.0	0.2	1.4	0.0	0.0
Minden TS M2 Muskoka TS M4 Relocate Tie	D-SR-10.13	4.8 km Relocation from Off-road to On-road	0.0	0.5	2.1	2.1	0.0
Minden TS M3 44KV Line Relocate	D-SR-10.14	1 km Relocation from Off-road to On-road	0.0	0.0	0.0	0.1	1.2
Morrisburg TS M23 Line Relocation	D-SR-10.15	1.2 km Relocation from Off-road to On-road	0.1	0.9	0.0	0.0	0.0
Muskoka TS M1 Parry Sound TS M2 Relocate	D-SR-10.16	10 km Relocation from Off-road to On-road	0.0	0.8	3.9	3.1	0.0
Muskoka TS M1 Relocate-Brackenrig-Ufford	D-SR-10.17	4.7 km Relocation from Off-road to On-road	0.0	0.9	2.9	5.1	0.0
Muskoka TS M1 Relocate-Hwy 169-Bala	D-SR-10.18	9.8 km Relocation from Off-road to On-road	0.0	0.6	3.7	2.0	0.0

Muskoka TS M1 Relocate-Pineland	D-SR-10.19	2.7 km Relocation from Off-road to On-road	0.0	0.3	2.8	0.0	0.0
Muskoka TS M1 Relocate-Windemere-Ufford	D-SR-10.20	6 km Relocation from Off-road to On-road	0.0	0.6	2.9	3.1	0.0
Muskoka TS M5 Relocate-Hwy141-Ullswater	D-SR-10.21	5.1 km Relocation from Off-road to On-road	0.0	0.5	1.9	3.1	0.0
Norfolk M3 Offroad Relocation - St Williams	D-SR-10.22	7 km Relocation from Off-road to On-road	0.0	1.0	8.7	0.0	0.0
Norfolk M3 Offroad Relocation - Turkey Point	D-SR-10.23	6.2 km Relocation from Off-road to On-road	0.0	0.0	0.5	4.5	0.0
Norfolk M3 Offroad Relocation - Vittoria	D-SR-10.24	7.2 km Relocation from Off-road to On-road	0.0	0.0	0.0	0.8	7.3
Orillia TS M2 M7 Relocate	D-SR-10.25	1.8 km Relocation from Off-road to On-road	0.0	0.2	2.2	0.0	0.0
Owen Sound TS M25 Hepworth Line Refurbishment	D-SR-10.26	9.7 km Rebuild On-road to increase conductor size	0.0	0.8	7.4	0.0	0.0
Paudash DS F1 Line Relocation	D-SR-10.27	3.5 km Relocation from Off-road to On-road	0.0	0.3	2.2	0.0	0.0
Town of Markdale Secondary Bus Refurbishment	D-SR-10.28	0.3 km Relocation from the side of a building to poles	0.0	0.1	0.9	0.0	0.0
Town of Schreiber Rebuild Phase 2	D-SR-10.29	0.5 km Relocation from Off-road to On-road	0.0	0.2	0.8	0.0	0.0
Wallace TS M6 Madawaska Relocate	D-SR-10.30	8.7 km Relocation from Off-road to On-road	0.0	0.7	6.7	0.0	0.0
Waubaushene TS M1 Rebuild	D-SR-10.31	3 km Relocation from Off-road to On-road	0.0	0.3	2.3	0.0	0.0
Other Projects (<$1M)			9.2	9.1	9.9	8.5	8.7
Total			9.3	28.1	105.5	48.8	17.2

APPENDIX B - DESCRIPTION OF INVESTMENTS IN ORILLIA RZ

Project Name	Net Capital Investment ($M)				
	2028	2029	2030	2031	2032
Other Projects (<$1M)	0.06	0.07	0.07	Embedded in Hydro One Networks	
Total	0.06	0.07	0.07		

APPENDIX C - DESCRIPTION OF INVESTMENTS IN PETERBOROUGH RZ

Project Name	Net Capital Investment ($M)				
	2028	2029	2030	2031	2032
Other Projects (<$1M)	0.03	0.03	0.03	Embedded in Hydro One Networks	
Total	0.03	0.03	0.03		

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

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One[1]	207.9	58.4	7.1	3.8	2.5	279.7
Orillia Rate Zone	2.04	0.00	0.00	Embedded in Hydro One Networks		
Peterborough Rate Zone	5.19	0.00	0.00			

Summary:

The primary trigger of the investment is regulatory compliance. Hydro One sought and was granted approval as part of the EB-2021-0110 proceeding for a significant, multi-year program to replace its legacy AMI 1.0 system with a new AMI 2.0 system. This investment involves completing the replacement of Hydro One's legacy AMI 1.0 system with a new AMI 2.0 system because it had reached end-of-life with meters showing conditions of disrepair, an increasing number of meter failures and increasing costs of performing individual reactive meter replacements. High meter failure rates, without intervention, pose significant and critical risks to reliable customer billing and Hydro One's operations. Hydro One plans to complete the project in 2029, one year later than originally planned. This variance reflects the additional time required to complete supplier contracts, build and integrate IT systems for reliable customer billing, and initiate meter and network replacement. The EB-2021-0110 AMI 2.0 project total net cost estimate adjusted for inflation was $705.6M[2] with a range of $599.8M - $846.7M (-15% to +20%). The forecast

[1] Prepaid expenditures related to cloud computing for this investment are currently included in Hydro One's revenue requirement as capital expenditures. However, the resulting impact on the revenue requirement is not material. Hydro One will revise presentation of these costs within the revenue requirement as part of an evidence update, or at the Draft Rate Order stage of the proceeding.

[2] The $705.6M amount reflects an update to the original evidence of $661.6M, escalated by 5.25% for inflation and a further 1.3% consistent with Undertaking JTU-1.19 in Proceeding EB-2021-0110.

total net cost estimate reflecting updated vendor costs, and more informed planning assumptions, is $799.4M which is approximately $47.3M below the upper bound of the total net cost inflation adjusted estimate. Net capital expenditures for the 2023-2027 period are forecast to be approximately $547M, $34M below the plan amount of $581M. The in-serviced amount in the current rate period is forecast to be approximately $499.3M, which is $81.7M below the ISA plan amount.

In addition to meeting regulatory compliance requirements, the AMI 2.0 investment enables the modernization of the Company's distribution system through grid edge computing and Distributed Intelligence and Distribution Automation (DIDA). Following the successful completion of Distributed Intelligence (DI) pilot activities in 2025, Hydro One added DI Implementation Phase 2 scope in the 2023-2027 period to begin realizing benefits as early as reasonably practicable and to maximize value over the 20-year service life of the AMI 2.0 system. Once foundational DI use cases are operationalized in the 2028-2032 period, DI is expected to deliver a range of grid facing benefits across all RRF outcome categories. Importantly, this investment addresses existing challenges and positions the Company with the flexibility and optionality to support future use cases that may be required to address evolving electrification needs and emerging customer service and system operational challenges.

1.0 INVESTMENT NEED

The key drivers of the AMI 2.0 investment remain unchanged (see EB-2021-0110 D-SR-12, Section B). In summary, given vendor attestations, observed meter failure trends, industry benchmarking and other studies, independent Accelerated Life Testing study results, the condition of assets (both physical and technological), and regulatory compliance considerations, it continues to be 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:

- Non-compliance with the Federal Electricity Gas and Inspection and Weights and Measures Acts, and the OEB's Distribution System Code.
- 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;
- Increasing field work and associated costs because of unplanned individual meter replacements and unscheduled manual meter reading;
- Higher labour costs for individual meter replacements relative to mass meter replacements;
- Higher unit meter costs relative to peers because of lower volume purchases for AMI 1.0 meters relative to bulk purchases associated with mass meter replacements;
- Replacement of failed meters with obsolete technology; and
- Lost opportunities for operational and customer service benefits associated with up-to-date technology and being able to respond to foreseeable emerging trends over the new system's 20-year service life.

Specifically, from a technological perspective as discussed in the previous rate application (EB-2021-0110, DSP Section 3.11, D-SR-12), AMI systems are similar to other types of information technology that become outdated and require periodic upgrading or replacement. However, unlike other forms of information technology, it is not practical to physically replace installed meters prior to the end of their useful service life, given the significant volume of devices, their broad geographic distribution, and their sealed design.

Accordingly, Hydro One's procurement of the AMI 2.0 system incorporates advancements in metering and communications technology that have emerged since the deployment of the AMI 1.0 system more than 15 years ago. The new AMI 2.0 meters incorporate embedded computing power, additional measurement capability, and more granular levels of sensing capability and storage. The secure communication network equipment has higher bandwidth and can support exponentially higher volumes of information from meters and other devices. These technological advancements, embedded in the AMI 2.0 hardware, provide opportunities to respond to current and future needs through grid edge computing, Distributed Intelligence and Distribution Automation (DIDA):

Distributed Intelligence (DI) refers to software-based applications, analogous to mobile phone applications, that operate on AMI 2.0 meters at the grid edge and communicate with Hydro One's back-office systems. These applications extend the role of meters beyond basic data collection for billing, enabling localized analysis and event detection that support a more efficient, resilient, and data-driven distribution system.

Distribution Automation (DA) refers to grid-focused capabilities that integrate physical devices—such as sensors and controls—operating over the AMI 2.0 communication network with Hydro One's back-office systems. DA capabilities support enhanced system monitoring, control, and operational responsiveness.

Distributed Intelligence (DI) grid-edge computing provides Hydro One with a flexible platform to respond to both current and future system and customer needs in alignment with the OEB's Renewed Regulatory Framework. From a Customer Focus perspective, DI improves outage identification and restoration accuracy by providing service-point-level visibility into grid conditions, addressing current limitations in visibility on rural feeders that rely largely on static connectivity records and field verification. It also provides the opportunity to develop and provide customer-level insights behind the meter to support more informed decision-making and improved customer experience. In terms of Operational Effectiveness, DI enables more accurate, data-driven planning and operations by reducing reliance on static records and labour-intensive field investigations, particularly on the secondary-side network. With respect to Public Policy Responsiveness, DI supports the integration of electrification, Distributed Energy Resources, and

Non-Wires Solutions by providing foundational analytics required to assess system constraints and emerging needs.[3] [4] [5] Finally, for Financial Performance, DI can help improve asset utilization and manage long-term system costs by enabling more targeted investments and helping avoid or defer premature infrastructure upgrades. Most significantly, the DI platform provides optionality over the life of the AMI 2.0 system by enabling a prudent, staged approach—allowing Hydro One to start quickly but at a limited scale, and to grow functionality incrementally once the platform is in place, informed by experience, performance, and evolving needs.

Absent this investment, Hydro One would continue to address many emerging electrification and secondary-side challenges primarily through labour-intensive field investigations, reactive equipment replacements, and traditional reinforcement practices, which are increasingly misaligned with strong customer support for improving day-to-day reliability, and shortening restoration times related to severe weather.

While DI is an emerging technology, Hydro One's DI plans are in alignment with other North American utilities replacing, or planning to replace, their AMI 1.0 systems with AMI 2.0 systems including:

- Tampa Bay Electric Company (TECO) has deployed several DI Apps (e.g., High Impedance, High Temperature, Locational Awareness, Active Transformer monitoring) to support its grid modernization strategy;[6]
- Xcel Energy's plans to modernize its distribution system include both customer and grid facing DI applications. Grid facing DI use cases prioritized for initial release include high impedance detection, locational awareness and EV detection.[7]

[3] Energy for Generations: Ontario's Integrated Energy Plan to Power the Strongest Economy in the G7, Chapter 4 Ontario's Future Electricity Grid, June 2025
[4] OEB Framework for Energy Innovation: Setting A Path Forward for DER Integration, January 2023, pg.3.
[5] OEB Non-Wires Solutions Guidelines for Electricity Distributors, 2024, pg.6.
[6] Direct Testimony of David Lukcic, Tampa Bay Electric Company, Florida Public Service Commission Docket No 20240026-E1, April 2024
[7] Xcel Energy Integrated Distribution Plan, Minnesota Docket E 002/M-23-452 Appendix J

- Niagara Mohawk plans to leverage grid edge computing and DI to enhance benefits for customers and the grid and is currently conducting a controlled roll-out grid edge computing real time load disaggregation for customers;[8][9]
- PG&E's AMI 2.0 roadmap for grid modernization includes developing, deploying, testing, and scaling DI applications for fault location and detection, customer load disaggregation, network model improvements, DER enablement, panel and service upgrade avoidance, and EV charging management;[10]

2.0 INVESTMENT DESCRIPTION

2.1 INTRODUCTION

This section is organized into four sub-sections. The first sub-section provides an overview of the AMI 2.0 program's goals and solution. The second sub-section identifies and discusses material variances in the AMI 2.0 program's schedule since its original submission in EB-2021-0110. Sub-section three provides a description of investments in the 2028-2032 period to complete the project. The final sub-section presents the company's progress in piloting, evaluating and implementing the modern functionality enabled by the AMI 2.0 system.

2.2 AMI 2.0 GOALS AND SOLUTION

The AMI 2.0 program's primary goal remains unchanged from the evidence provided in EB-2021-0110 D-SR-12: to replace Hydro One's AMI 1.0 system in an economically and operationally optimal manner, thereby maintaining compliance with applicable federal and provincial metering and billing requirements. While the underlying AMI 2.0 solution itself also remains unchanged, additional detail is now available regarding the modern functionality enabled by the system and how that functionality will be implemented and utilized (see Section 2.5).

AMI 2.0 is a foundational investment in a modern AMI platform to address foreseeable needs over its 20-year service life. The AMI 2.0 solution includes equivalent core

[8] Advanced Metering Infrastructure Grid Edge Computing Report. Niagara Mohawk d/b/a National Grid. March 21.2022
[9] AMI Semi-Annual Metrics Report. Niagara Mohawk d/b/a National Grid. Nov 30,2025.
[10] PG&E Grid Modernization Report, April 2024

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 are in alignment with functions that comparable utilities are employing or planning to deploy in their AMI 2.0 systems. In summary, the AMI 2.0 solution includes the following characteristics and features:

- A 20-year service life, warranted by the vendor;
- Employs 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 network equipment required for a healthy mesh network and is expected to increase the number of customers that can be reached by the network; and
- Employs enhanced security to protect data against cyber and other security threats.

AMI 2.0 also helps to address the needs of customers over the course of the investment’s 20-year service life, including:

1. All AMI 2.0 residential meters are 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;
2. AMI 2.0 meters incorporate embedded computing capabilities, enhanced measurement functionality, and more granular sensing and data storage. These capabilities enable grid modernization through the deployment of software-based applications that support improvements in customer service, reliability, safety, and data-driven planning at the grid edge (e.g., the ingestion of meter and DI data by the planned Advanced Distribution Management System supporting improved grid Operations). As with other digital platforms, a key element of the AMI 2.0 system’s value is its flexibility to deploy applications to address current operational requirements and to respond to future challenges as they emerge; and
3. 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 where appropriate in the future.

2.3 AMI 2.0 SCHEDULE VARIANCES

The AMI 2.0 schedule set out in EB-2021-0110 D-SR-12 was organized in three largely interdependent sequential phases: 1) Pre-Deployment Request for Proposal (RFP); 2) Planning, HES and Pilot; and 3) Mass Deployment. It was prepared and submitted at the outset of the pre-deployment phase of the program and as such more refined plans are now in place with a more mature program schedule. This sub-section of the ISD provides a revised forecast schedule and discusses key drivers of variances from EB-2021-0110.

Figure 1 below compares the original AMI 2.0 Schedule from EB-2021-0110 to the Revised Forecast Schedule by program phase.

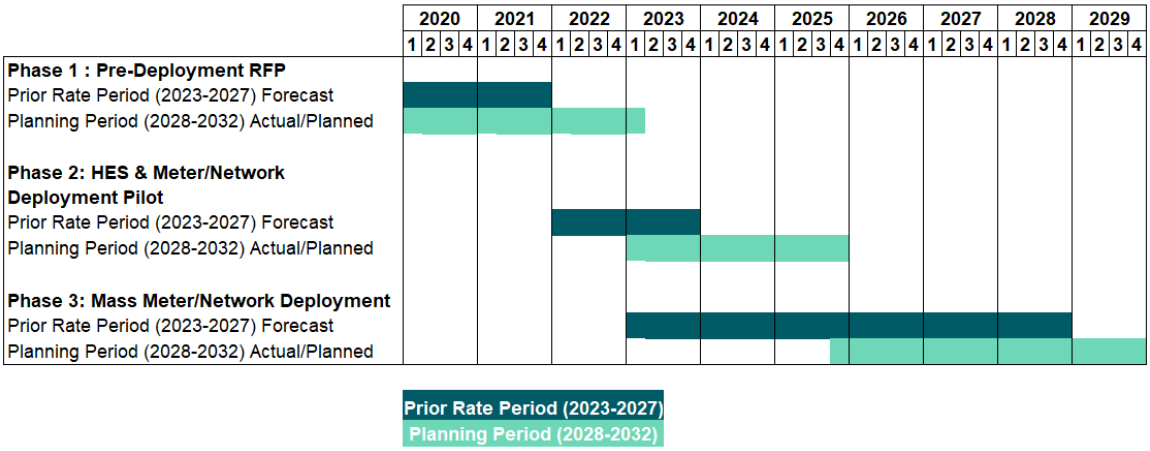


Figure 1: Original AMI 2.0 Schedule vs. Revised Forecast Schedule

Hydro One now forecasts completion of the installation of AMI 2.0 network equipment and meters in 2029, one year later than originally planned. In summary, the schedule variance is primarily attributable to an underestimation of the complexity associated with certain activities within the program phases including vendor contract negotiations, information technology assessments, and Head-End System (HES) integration, together with the critical-path interdependencies among these activities. As these activities are largely

sequential and interdependent, key milestones such as the commencement of the end-to-end AMI 2.0 pilot could not proceed until the HES was installed, fully integrated, and successfully tested.

As part of its AMI 2.0 Project Execution Review conducted by E-Source (DSP Section 3.3, Attachment 3), E-Source assessed Hydro One's deployment progress and execution approach in the context of comparable industry programs. E-Source found that, despite execution challenges encountered during implementation, Hydro One's forecasted deployment timeline remains generally aligned with the market scan group of utility programs, particularly when considering the scale of deployment, lower meter density, coexistence of legacy and next-generation AMI environments, and Ontario-specific implementation requirements.[11]

In addition, E-Source found that Hydro One has maintained overall schedule control through phased execution strategies and the concurrent execution of key activities. While the forecasted completion date is approximately one year later than the original baseline, E-Source considers the updated program timeline to remain reasonable considering the challenges encountered.[12]

A summary of specific schedule variances by program phase is provided below.

Phase 1: Pre-Deployment RFP Schedule Variances

The Pre-Deployment RFP phase of the program, initiated in 2020, focused on the competitive procurement of a new AMI 2.0 system (the vendor for meters, network equipment, and HES), a vendor for Solution Integration Services (Program Management Office, IT integration, and meter/network design and deployment), along with the negotiation, and then arbitration, of a Purchased Service Agreement (PSA) with the Power Workers Union (PWU). Originally forecast to be complete in Q4 2021, negotiations with program vendors and reaching a PSA with the PWU were much lengthier than planned. In turn, concluding vendor procurement contracts were a pre-requisite to establishing the

[11] DSP Section 3.3 – Attachment 3, p.31.
[12] DSP Section 3.3 – Attachment 3, p. 5

PMO and the commencement of early planning activities and these tasks were also delayed. While the negotiations with vendors to contain input cost pressures achieved financial terms and protections for the benefit of ratepayers, and while partial statements of work were issued to vendors to mitigate delays, Phase 1 was not fully completed until Q2 2023.

Phase 2: Planning, Head End System (HES) Implementation and Pilot Schedule Variances

Phase 2: Planning, Head End System (HES) Implementation and Pilot, involved detailed program planning; testing and certification of the AMI 2.0 meters and network devices; the design, installation, integration and testing of the HES; and conducting a field trial with approximately 10,000 meters to end-to-end test the AMI 2.0 solution (network design and installation, meter deployment logistics and installation, HES and back-end system testing, and billing). Phase 2 was originally forecast to begin in Q1 2022 and be completed in Q4 2023. Phase 2 work began in Q1 2023 and was largely completed in Q4 2025. The key drivers of this variance in schedule were as follows:

- The start date for Phase 2 was dependent on the successful completion of Phase 1 vendor selection and consequently resulted in a start date variance of approximately 1 year;
- An underestimation of the complexity in ensuring accurate and reliable customer bills when transitioning from AMI 1.0 to AMI 2.0, and more specifically:
    - A higher than estimated time for foundational planning activities, particularly in the areas of business process development and training;
    - An underestimate of the time for Information Technology (IT) discovery, assessment and implementation activities with respect to integrating and implementing the new AMI 2.0 HES with internal IT systems and the IESO's Meter Data Management Repository (MDMR);
    - A higher than estimated time by the vendor in creating and addressing defects associated with the CMEP file (California Metering Exchange Protocol) used by the IESO MDMR for energy market data transfer led to an approximately 6-month delay.

- The dependency of commissioning the AMI 2.0 HES which was a prerequisite to launching the AMI 2.0 pilot (enabling end-to-end testing of the entire AMI 2.0 system). The successful execution of the pilot was critical to proactively mitigate risk associated with the transition from AMI 1.0 to AMI 2.0 and in ensuring and improving readiness of the people, processes, and technology for sustained high volume mass network and meter deployment for reliable and accurate customer billing.

While launching the end-to-end pilot was delayed due to later than planned HES availability, the results of the pilot showed that the AMI 2.0 system outperformed AMI 1.0 in billing accuracy, reliability, and communication under normal conditions and its resiliency in recovering from adverse weather events (e.g., the 2025 ice storm).

Phase 3: Mass Deployment Pre-Installation Planning and Implementation Schedule Variances

Phase 3 of the program involves two distinct but related activities: pre-installation mass deployment planning and the mass deployment of AMI 2.0 communication network equipment and meters. While many meter pre-installation planning activities were able to occur concurrently with Phase 2 activities (such as the ordering of meters and network equipment, resource planning, training, etc.), mass network and meter deployment ramp up could not begin until Q4 2025, approximately 2 years later than initially forecast, due to Phase 2 dependencies of HES implementation and pilot completion. Consequently, mass meter and network deployment did not begin until late 2025.

Table 1 below provides the revised forecast meter deployment schedule compared to the originally forecast schedule from EB-2021-0110 D-SR-12 representing a volume variance of approximately 422,000 meters in the 2023-2027 period. Meter deployment is now planned to be complete in 2029, one year later than originally forecast.

Table 1 - Comparison of EB-2021-0110 Meter Deployment Plan and Updated 2028-2032 Meter Deployment Forecast

	2023	2024	2025	2026	2027	2028	2029
Plan*	3,458	149,153	369,909	369,323	369,073	223,646	
Actuals / Latest Forecast*			97,693	363,155	377,568	489,893	148,352

** 2028-2032 meter volume totals are based on forecast-time estimates and are subject to change as underlying assumptions evolve (e.g., new or revised customer connection projections).*

Table 2 below provides the revised forecast communication network device deployment schedule compared to the originally forecast schedule from EB-2021-0110 D-SR-12 representing a volume variance of approximately 2,147 devices in the 2023-2027 period.

Table 2 - Comparison of EB-2021-0110 and Updated 2028-2032 Network Device Deployment Forecast

	2023	2024	2025	2026	2027	2028	2029
Plan*	385	1,275	3,091	3,141	3,186	2,047	
Actuals / Latest Forecast*		204	2,156	3,045	3,526	3,027	0

**Communication network device totals in EB-2021-0110 were based on estimates. Communication network device totals in 2028-2032 plan are based on engineering network designs and estimates at time of forecast.*

Figure 2 below provides the forecast geographic service territory coverage of AMI 2.0 (Itron) through the end of 2026.

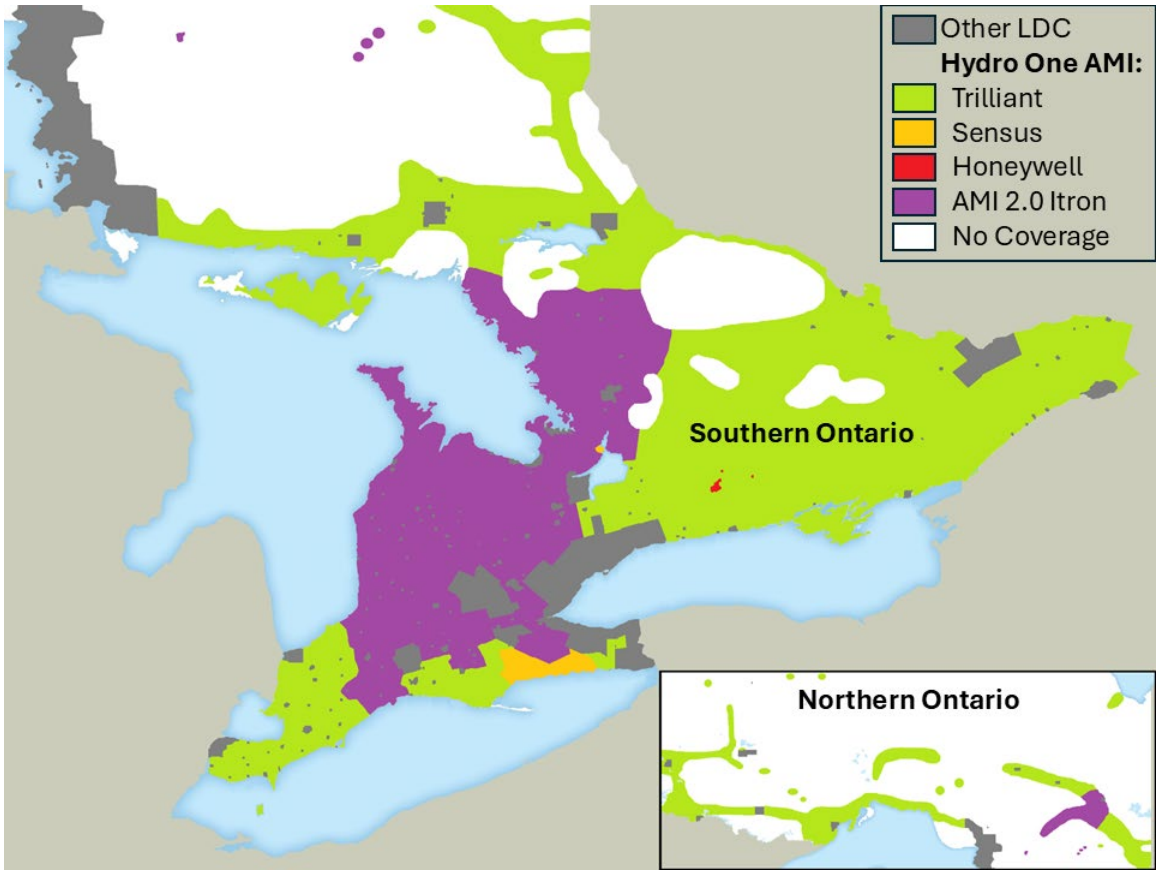


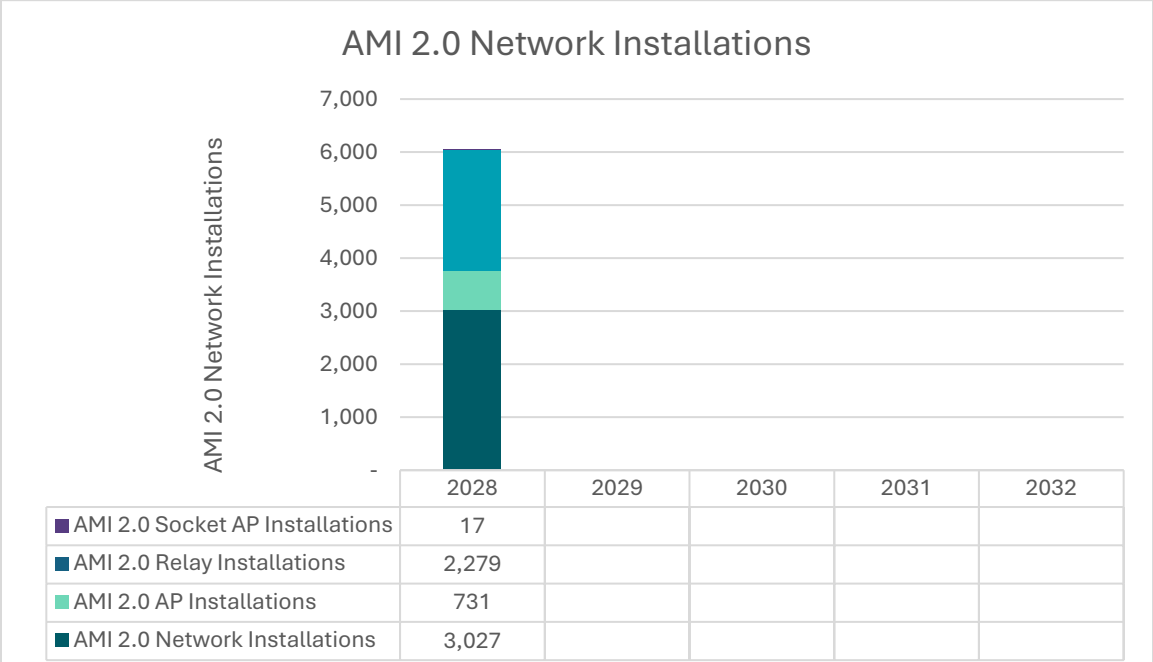
Figure 2: Forecast AMI 2.0 Meter Geographic Coverage at End of 2026

2.4 AMI 2.0 METER AND NETWORK DEPLOYMENT INVESTMENT DESCRIPTION 2028-2032

The AMI 2.0 investments planned for the 2028-2032 period are directed toward achieving full program completion by enabling end-to-end advanced metering functionality across remaining areas of the service territory. These investments are organized around two principal workstreams: (i) the completion of the AMI 2.0 communications network to ensure reliable, secure, and ubiquitous connectivity; and (ii) the mass deployment of AMI 2.0 meters, culminating in the transition of customers to AMI 2.0–based billing operations and associated operational capabilities.

2.4.1 COMMUNICATION NETWORK DESIGN AND INSTALLATION

AMI 2.0 network design involves planning the placement of communication network devices including Access Points, Relays, and Socket Access Points, within defined geographic sectors to ensure reliable transmission of meter data to Hydro One's AMI 2.0 Head-End System (HES). Network design is undertaken in advance of meter deployment and includes iterative validation of proposed device locations through a combination of back-office network engineering analysis and field-based scouting activities. Once network design for a geographic sector is finalized, network devices are installed and optimized. Figure 3 presents the planned communication network device deployment volumes for the 2028-2032 period.



	2028	2029	2030	2031	2032
AMI 2.0 Socket AP Installations	17				
AMI 2.0 Relay Installations	2,279				
AMI 2.0 AP Installations	731				
AMI 2.0 Network Installations	3,027				

Figure 3: Forecast Network Deployment Device Volumes by Year 2028-2032

2.4.2 MASS METER INSTALLATION

Mass meter deployment encompasses the project management, planning, and logistical activities required to execute meter installations within a defined geographic sector. The installation process includes customer notification of a brief service interruption, removal of the existing AMI 1.0 meter, installation of the AMI 2.0 meter, and registration of the meter at the customer premise. As part of commissioning, meter communications are tested, followed by a monitoring and triage process to identify meters that do not immediately associate with the communication network and to resolve any issues where required. Figure 4 presents the planned meter installation volumes for the 2028–2032 period by year.

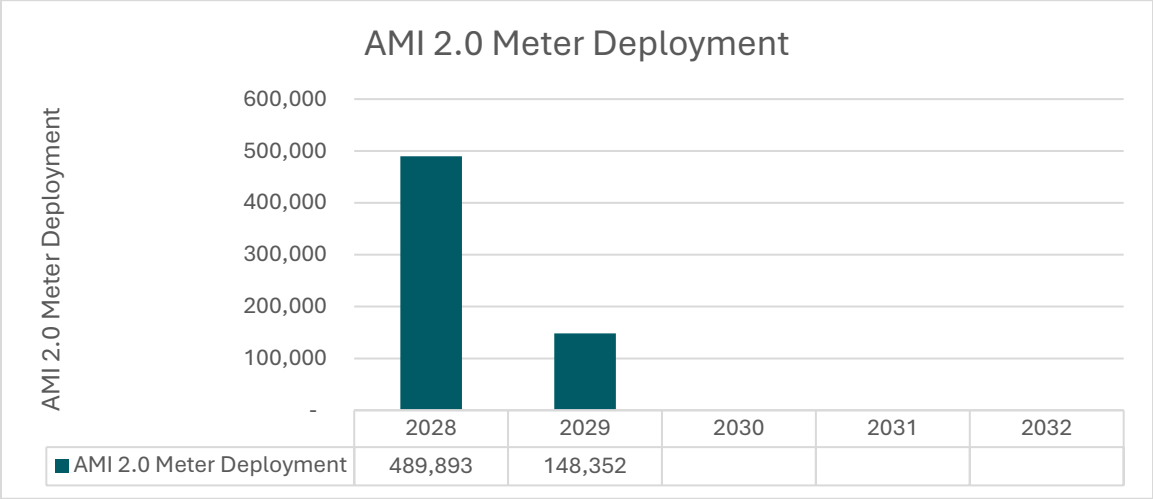


Figure 4: Forecast Meter Deployment Volumes by Year 2028-2032

The meter deployment plan in the 2028-2032 period reflects information available at the time of filing, based on early deployment experience starting in 2025. As a result, greater pacing uncertainty exists in the later years of the plan, as sustained, steady-state deployment productivity has not yet been fully demonstrated at scale. This uncertainty is further increased by the planned transition in 2027 from the third-party meter installation vendor to Hydro One employees in accordance with provisions of the Purchased Service Agreement arbitrated with the Power Workers Union, which introduces additional pacing and associated cost risk. Accordingly, forecast volumes and deployment pacing remain

subject to refinement, and the deployment plan is expected to be updated as actual performance is observed and validated through ongoing execution.

2.5 AMI 2.0 MODERN FUNCTIONALITY: DISTRIBUTED INTELLIGENCE AND DISTRIBUTION AUTOMATION SCOPE 2023-2027 AND 2028-2032

2.5.1 INTRODUCTION

The modern functionality enabled by the AMI 2.0 system is collectively referred to as grid edge computing Distributed Intelligence and Distribution Automation (DIDA). Hydro One's approach to advancing these capabilities across the 2023-2027 and 2028-2032 periods reflects a deliberate, staged strategy focused primarily on Distributed Intelligence (DI), where value potential is most clearly established. Consistent with a prudent, risk-managed implementation approach, investments in Distribution Automation (DA) in the 2028-2032 period are limited to targeted piloting activities to further validate use cases prior to any broader deployment.

Grid-edge computing and Distributed Intelligence (DI) are complementary, but distinct concepts enabled by the AMI 2.0 platform. Grid-edge computing refers to the capability to perform data processing at or near the customer service point, specifically within AMI 2.0 meters, rather than relying exclusively on centralized back-office systems. This capability allows information to be processed closer to where grid conditions are observed, reducing latency, improving data granularity, and enabling more timely insights. AMI 2.0 meters are engineered with a modular "sandboxed" architecture that partitions: 1) the revenue-grade metrology for billing; 2) the DI computing environment; and 3) the communications module. This physical and logical separation addresses security by ensuring software updates, or DI Applications, cannot interfere with core billing functions or provide an unauthorized gateway to the utility's broader back-office systems.

Distributed Intelligence represents the software-based applications (Apps) that operate within this grid-edge computing environment. DI Apps leverage the embedded computing, sensing, and storage capabilities of AMI 2.0 meters to analyze local conditions, such as

voltage, load, power quality, or connectivity, and generate actionable information for operational, planning, or customer-facing purposes.

Together, grid edge computing provides the foundational platform, while DI Apps deliver the specific functional capabilities. Grid edge computing enables DI applications to operate efficiently at scale, while DI translates grid-edge data into practical insights that can support improved system visibility, data-driven planning, and enhanced customer and operational outcomes. This layered architecture allows Hydro One to deploy and evolve functionality over time in a controlled manner, addressing current system needs while maintaining flexibility to respond to future challenges over the service life of the AMI 2.0 system.

While DI Apps represent the underlying software deployed at the grid edge, the value of DI is realized through the use cases they enable. Individual DI Applications provide specific analytical or sensing functions; however, it is the integration of these applications with Hydro One's operational and planning processes that gives rise to defined DI use cases (discussed later in this section).

Figure 5 below provides an overview of the DI IT Architecture and data flows. At a high level, the DI architecture begins at the meter, where DI applications perform localized processing to analyze conditions and detect events such as high-impedance faults. Event data are transmitted over the AMI 2.0 communications network to the vendor-hosted cloud environment and subsequently routed to Hydro One's Enterprise Data Platform for secure data storage and analytics. From there, information is distributed to relevant Hydro One on-premise enterprise systems based on its intended use. For grid-facing use cases, insights are delivered to appropriate Hydro One employee user interfaces to support operational and planning activities. For potential future customer-facing use cases, information may be made available to customers through designated customer channels.

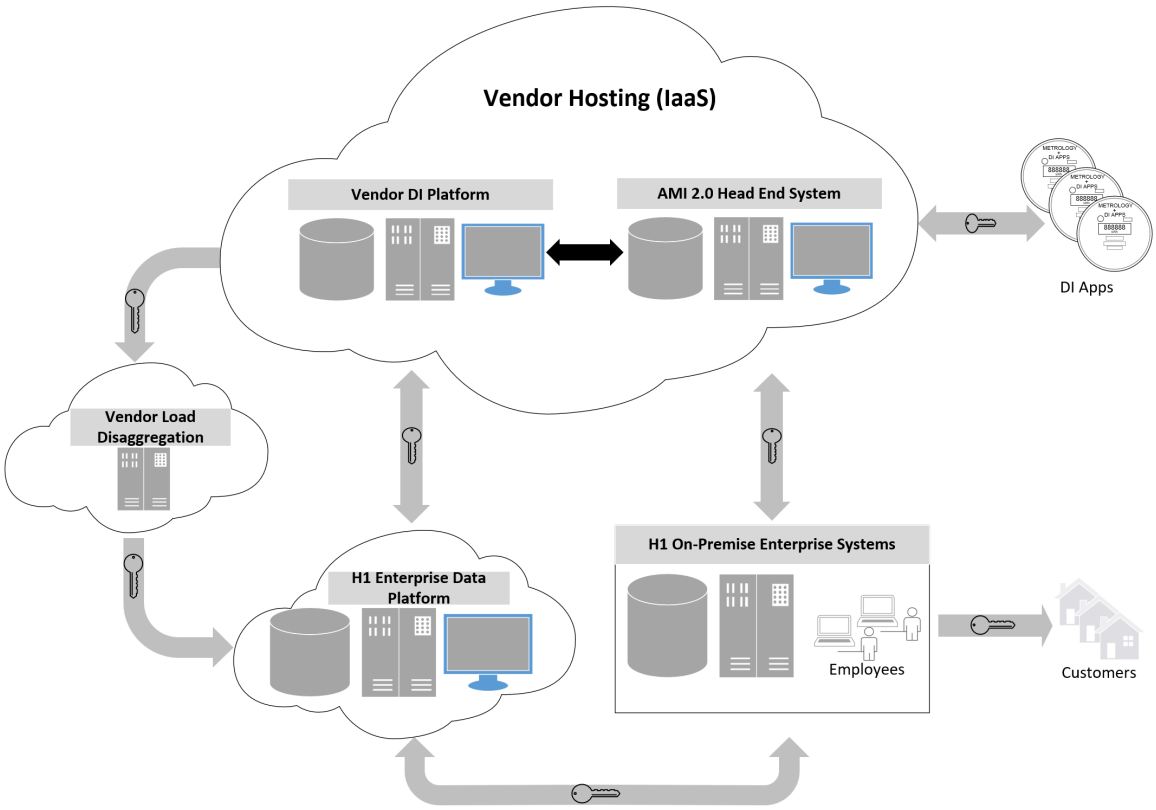


Figure 5: DI Architecture Overview

Hydro One's planned approach to advancing the modern functionality enabled by the AMI 2.0 system, identified in EB-2021-0110, D-SR-12 Section F, was through a prudent, staged framework, under which discovery and piloting activities were included within the original scope of the AMI 2.0 investment to validate technology performance and value. Implementation of Distributed Intelligence functionality, however, was not originally included in the 2023-2027 period due to uncertainties related to cost, functional performance, and system integration requirements. Following positive results from DI functional testing, favorable negotiations with the vendor on Application subscription fees, and to ensure initial DI benefits could begin to be realized as early as reasonably possible over the AMI 2.0 system's 20-year service life, Hydro One advanced DI implementation into the 2023-2027 period by allocating funding from within the AMI 2.0 program.

DIDA is a multi-year investment spanning two investment periods, with an initial focus on grid-facing Distributed Intelligence (DI) planning applications. Hydro One has adopted a

measured “start quickly but small” approach, advancing DI through staged implementation and the selective use of cloud-based infrastructure. This approach is intended to allow the Company to validate use cases, monitor operational performance, and evaluate market and technology developments prior to any expansion in scope or scale. The DIDA investment is structured across three interdependent and sequential phases: Phase 1 - Discovery, Piloting, and Evaluation; Phase 2 - Implementation; and Phase 3 - Operationalization and Realization, as illustrated in Figure 6.

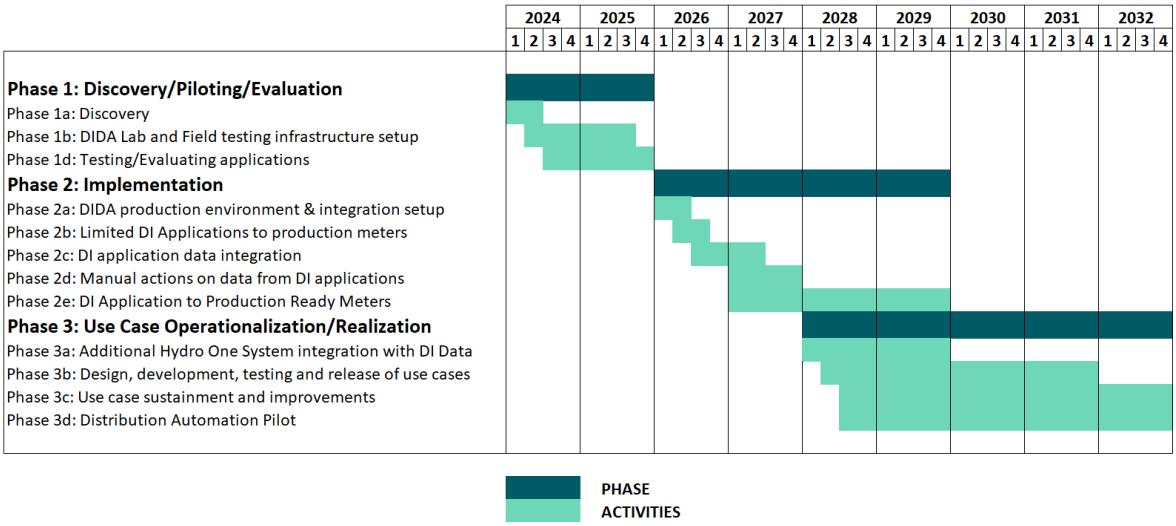


Figure 6: DIDA Phases: 2024-2032

DIDA costs comprise a combination of capital investments, prepaid cloud expenses, and OM&A expenses. Phase 1 (Discovery, Piloting, and Evaluation) was included within the scope of the original AMI 2.0 investment. Phase 2 (Implementation) was subsequently advanced and incorporated into AMI 2.0 Project costs as part of this investment. DIDA Phase 3 2028-2032 (Operationalization and Realization) builds on Phase 2 scope and includes a combination of capital and prepaid cloud expense (see Section 4.0), and OM&A expense (see Exhibit E-03-02, Section 2.3.5).

2.5.2 DIDA DISCOVERY/PILOTING/EVALUATION PHASE 1: 2023-2025

DIDA Discovery/Piloting/Evaluation phase activities focused on the validation of DI functionality through small-scale testing and deployments in controlled environments allowing Hydro One to monitor performance, security, identify and document business and customer impacts, validate expected outcomes, and define foundational technical integration/scope requirements for Hydro One systems in preparation for implementation. More specifically, the scope of Phase 1 Discovery/Piloting activities involved:

- **Acquiring and configuring DIDA core infrastructure:** This foundational infrastructure was required irrespective of which Distributed Intelligence (DI) Applications were ultimately deployed and included vendor professional services, software licences, hosting services, and equipment necessary to support DIDA discovery activities, as well as Hydro One internal effort to establish and configure the environment.
- **Establishing a Centralized and Living DI Laboratory:** A temporary centralized laboratory was established at Hydro One's AMI Operations Centre and equipped to test approximately 50 meters with Distributed Intelligence applications (see Figure 7). In parallel, a "Living Laboratory" was established using volunteer customer sites, where dual meters were installed in an operational environment to test and validate DI functionality under real-world conditions (see Figure 8).
- **Executing discovery activities:** Conducting targeted testing and evaluation to validate DI application functionality, performance, and operational suitability.
- **Developing foundational use cases:** Identifying foundational DI use cases informed by discovery and piloting results.



Figure 7: Distributed Intelligence Centralized Laboratory



Figure 8: Dual Meter Configuration Living DI Laboratory

Figure 9 below provides a description of the 8 DI Apps and one cloud-based solution that were piloted and assessed based on a range of requirements, and Figure 10 summarizes the results of that assessment.

DI Pilot Application Summary Descriptions		
App Identifier	**App Name**	**Description**
1	High Impedance Detection	Detects high-impedance connections (poor electrical connections) in the low voltage secondary network between the distribution transformer and end-user consumer meter. Early warning enables crews to mitigate the situation before the end-user consumer is impacted.
2	Location Awareness	Determines how each meter is electrically connected in the distribution grid, including distribution transformer, phase, and feeder/substation bank. Connections are compared to utility systems of record (usually Geographic Information System (GIS)) and discrepancies reported for update of those systems.
3	Active Temperature Monitoring	Detects developing hot meter connections (e.g., meter jaw issues) before they create a safety hazard or an unplanned outage through correlations between temperature and variables such as load, weather, and location.
4	Active Transformer Load Monitoring	Provides bi-directional load information on distribution transformers. The application also provides transformer load statistics, such as daily load duration, peak load, etc. to the back office for non-real-time analysis.
5	Active Transformer Voltage Monitoring	Provides frequent voltage conditions in the secondary LV (Low Voltage) system served by a distribution transformer. The application also provides transformer LV statistics, such as average, high, low, etc. to the back office for non-real-time analysis.
6	Meter Bypass Detection	Detects when an end-user consumer attempts to avoid paying for all or some electrical consumption by installing short electrical conductors from line side of the meter to the load side, bypassing the metrology.
7	Load Disaggregation	Provides disaggregation for whole premise electric load into the individual electric appliances and load. This information can be used for customer engagement and utility operations applications and programs. Disaggregation can be performed using DI real time data over Wi-Fi or using AMI interval data provided over the mesh.
8	Consumer Energy Stream Agent	The Consumer Energy Stream Agent enables real-time streaming data to be shared over Wi-Fi to 3rd party applications in the cloud.
9	EV Awareness	EV Awareness disaggregates Electric Vehicle (EV) charging load at a customer premise, providing disaggregation information with events delivered with less than a 5-minute latency when an electric vehicle starts or stops charging.

Figure 9: Pilot DI Application Descriptions

DI Application Pilot: Summary of Results										
Requirement	**Description**	**App 1**	**App 2**	**App 3**	**App 4**	**App 5**	**App 6**	**App 7**	**App 8**	**App 9**
Functionality	Meets the app defined functions	☑	☑	☑	☑	☑	☒	☑	☑	☑
Interoperability	Operates independently of metrology	☑	☑	☑	☑	☑	☑	☑	☑	☑
Connectivity	Supports connection to all required sources	☑	☑	☑	☑	☑	☑	☑	☑	☑
Data Access	Supports ability to retrieve data into a data historian	☑	–	☑	☑	☑	☑	☑	☑	–
Performance	Process required records for daily reporting	☑	☑	☑	☑	☑	☑	☑	☑	☑
Error Handling	Logs and manages errors and faults	☑	☑	☑	☑	☑	☑	☑	☑	☑
Security Compliance	Meets encryption and access control standards	☑	☑	☑	☑	☑	☑	–	☑	☑
Scalability	Operates with multiple apps installed	☑	☑	☑	☑	☑	☑	☑	☑	☑
Improved Business Ops	Measurable improvement for business operations	☑	☑	☒	☑	☑	☒	☑	☑	☑

☑ - Pass
☒ - Fail
– - Neutral or work in progress

Figure 10: Summary of Distributed Intelligence Application Pilot Assessment Results

Two applications - Active Temperature Monitoring and Meter By-Pass Detection, were eliminated from further assessment as they did not initially demonstrate measurable

improvements in business performance or failed to meet defined functional requirements. Assessment of the Consumer Energy Stream Agent (CESA) is ongoing.

Hydro One identified six foundational DI use cases as the initial focus for advancing DI capabilities: Improved Grid Hierarchy, Customer Load Visibility & Insights, Enhanced Asset Planning, Optimized Power Quality Monitoring, Non-Wires Solutions (NWS) Design & Integration, and DER Enablement. Table 3 below provides a summary description of the six foundational DI use cases and expected near-term benefits planned to be realized in the 2028-2032 period.

Table 3 - Summary Descriptions of Foundational DI Use Cases and Benefits

Summary Descriptions of Foundational Use Cases and Benefits	
1. Improved Grid Hierarchy	Delivers locational awareness capability providing a single authoritative view of customer-to-transformer connectivity.
Benefits	• Accurate digital representation of grid and its asset is foundational to all use cases. • Outages can be identified accurately because the system knows exactly how customers are connected; • Restoration efforts can be more targeted, facilitating reduced outage durations, and indirectly improving employee/customer safety; and • Planned maintenance and upgrades are based on actual field conditions, leading to fewer field investigations.
2. Load Visibility and Insights	Delivers visibility of load profiles and insights from the individual service-point up through to service transformer level. It supplements assumption driven loading tables and analysis with auditable, data driven visibility and analytical insights, delivering: 1) accurate transformer level load profiles incorporating seasonality and coincidence factors; 2) customer level signatures for electrification loads; and 3) operational insights with ease of data access.
Benefits	• Data driven assessment of new connections and upgrades, avoiding premature capital investment. • Clearer guidance on capacity constraints (EVs, DERs, etc.) • More efficient and effective service upgrade decisions through disaggregated usage views, load monitoring on transformer level and localized load insights

Summary Descriptions of Foundational Use Cases and Benefits	
3. Optimized Customer Power Quality Monitoring and Management	Delivers DI app data (e.g., voltage monitoring) for structured remote detection and triage of power quality issues at the consumer service point level enabling early screening and faster customer power quality issue resolution.
Benefits	• Reduced field investigations • Faster identification of potential equipment issues • Accelerated power quality resolution
4. Design and Integrate Non-Wires Alternative	Delivers analytics to help identify, design, and evaluate NWAs (e.g., managed EV charging, demand management programs, etc.) for locations where load relief can defer or avoid traditional upgrades, using trusted connectivity and existing DI data sets (e.g., Locational awareness, Transformer Load Monitoring, Transformer Voltage monitoring, EV awareness), and outputs from other foundational use cases.
Benefits	• Lower long-term system costs by avoiding or deferring traditional builds • Granular visibility and breakdown of loads will allow designing more targeted programs for demand reduction • Identify constraint areas with more confidence resulting in increased potential candidates for NWSs
5. DER Enablement	This use case allows for better visibility of loads and DERs <12kW, enabling more accurate planning of DER Hosting Capacity and more efficient use of existing capacity. This use case is achieved through combining data from several DI Apps (DI Load and Voltage Monitoring, Load Disaggregation, Locational Awareness), AMI 2.0-meter data, and analytics.
Benefits	• More accurate assessment of DER applications without defaulting to potentially conservative assumptions • Unlocking DER capacity on the system by enabling more efficient use of existing assets, enabling more sustainable energy choices for customers • Better visibility of DER customers, giving more options to manage DERs and better input into future planning • Increasing the accuracy of grid models which can increase the possibility of study automation and potentially reduce new customer application timelines.
6. Enhanced Asset Planning	Operationalizes data driven planning (as opposed to planning using static or nameplate data). With automated updates in place,

Summary Descriptions of Foundational Use Cases and Benefits	
	planners see current, measured loading and credible forward views without the need for data manipulation.
Benefits	• More granular data (such as at the service transformer level) for enhanced asset planning

2.5.3 PHASE 2: DISTRIBUTED INTELLIGENCE IMPLEMENTATION 2026- 2027

Phase 2 Implementation activities focused on establishing the foundational technology, processes, and capabilities required to operationalize DI and enable the realization of benefits from the foundational DI use cases in the 2028-2032 period.

More specifically, the forecast scope of Phase 2 Implementation included:

- **Establishing common DI production infrastructure:** Configuring the vendor-hosted DI platform, including the systems used to deploy applications to meters and ingest application data over the AMI 2.0 communications network.
- **Establishing foundational system integrations:** Developing non-use-case-specific integrations between the vendor DI platform and Hydro One systems, including the Hydro One Cloud Data Store, AMI 2.0 Head-End System, and on-premise enterprise systems.
- **Deploying DI applications to production meters:** Pushing selected DI applications over-the-air to production-eligible meters in alignment with the AMI 2.0 deployment plan.
- **Developing operational procedures:** Establishing business procedures to manage, monitor, and respond to events generated by DI applications.
- **Training and enablement:** Providing training to support the operation, administration, and integration of the DI platform and applications.
- **Planning use-case integration:** Developing implementation plans for integrating use-case-specific DI data into Hydro One systems to support operational and planning processes.

2.5.4 PHASE 3: DISTRIBUTED INTELLIGENCE OPERATIONALIZATION / REALIZATION 2028-2032

Phase 3 Operationalization and Realization investments build on the foundational capabilities established in Phase 2 and focus on integrating DI functionality into Hydro One's operational and planning processes to enable sustained benefit realization. More specifically, the scope of Phase 3 includes:

- **Building end-to-end system integrations:** Developing and implementing use-case-specific integrations between the vendor-hosted DI platform and Hydro One enterprise systems (e.g., Geographic Information System, Customer Information System) to operationalize foundational DI use cases.
- **Developing advanced analytics and decision-support tools:** Creating and deploying analytical and decision-support capabilities that leverage DI data for use across Hydro One organizations, including Planning and Operations.
- **Sustaining DI capabilities:** Maintaining DI applications and supporting infrastructure, including ongoing hosting, subscriptions, and application support.
- **Enabling in-house application development:** Procuring a Software Development Kit (SDK) to enable Hydro One to develop, test, and deploy DI applications internally in response to emerging needs, as an alternative or in combination with vendor-provided applications.
- **Refining and Assessing New DI use cases:** Refining existing DI use cases and assessing new use cases informed by operational experience and evolving needs.
- **Piloting Distribution Automation (DA) capabilities:** Conducting targeted pilots of Distribution Automation devices to evaluate performance and suitability prior to any future deployment.

3.0 OUTCOMES

3.1 OEB RRF OUTCOMES

The outcomes of the AMI 2.0 program remain unchanged from EB-2021-0110, DSP Section 3.11, D-SR-12 and in summary, the 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 (reduced field visits for manual meter reading and disconnection/reconnection requests), reduction in maintenance of network equipment, reduction in HES costs, and provision of new data sets for operational decision-making;
- Enable AMI 2.0 distributed intelligence to support public policy responsiveness, increase operational effectiveness and financial performance, and improve customer service.

Table 4 below presents anticipated benefits as a result of the investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 4 - Outcome Summary

Outcome	Description
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 and Ultra-Low 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 advancements in security architecture; • Improving customer safety, targeting outages more accurately and therefore reducing outage duration, reduced risk of unplanned outages through enabling AMI 2.0 distributed intelligence functionality (e.g., load disaggregation, EV awareness, high impedance detection, locational awareness, Transformer Voltage and Load Monitoring).

Outcome	Description
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; • Increasing efficiency in managing service contracts and inventory by moving from multiple hardware and software vendors to a single vendor; • Maintaining operational efficiencies enabled by AMI 1.0; and • Improving distribution system visibility and support planning and effective operational decision-making through distribution intelligence data (meter locational awareness, transformer load and voltage monitoring, and high impedance detection)
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; • Compliance with OEB Distribution System Code Section 4.2 regarding disconnection and reconnection process. • *Supports Ontario's Integrated Energy Plan (2025), Framework for Energy Innovation: Setting the Path Forward for DER Integration (2023), and Non-Wires Solutions Guidelines for Electricity Distributors (2024)* through DI foundational use case enablement.
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; • Reducing field work costs as a result of the deployment of remote disconnect/reconnect functionality for some types of requests. • Reducing network maintenance costs through the need for less network equipment relative to AMI 1.0 • Enabling DI Transformer Load and Voltage Monitoring to help avoid or defer infrastructure upgrades

4.0 EXPENDITURE PLAN

INTRODUCTION

This section is organized into three sub-sections. AMI 2.0 Total Cost Forecast section provides updated total cost forecast for the AMI 2.0 program, including a description of the key drivers of variances from the project estimate provided in the previous proceeding (EB-2021-0110).The 2023-2027 Expenditures section presents the variance explanations for the prior rate period (2023 – 2027) and the 2028-2032 Expenditures section provides forecast investments for the planning period (2028-2032) to complete the meter and network installation component of the project in 2029, together with forecast DIDA Phase 3 (Operationalization/Realization) costs for the same period.

AMI 2.0 TOTAL COST FORECAST

The AMI 2.0 total cost forecast filed in EB-2021-0110 was developed in accordance with industry-accepted estimating practices and reflected the best information available at the time of filing. Meter and network hardware cost estimates were informed through market testing conducted via a Request for Information (RFI) process. Planning assumptions were grounded in Hydro One's experience with the AMI 1.0 deployment, including the transition from manual meter reading to over-the-air metering, while recognizing the additional complexity associated with migrating between two over-the-air systems. At the time of filing, costs associated with system integration services including program management, information technology integration, and meter deployment, had not yet been market-tested, as the System Integrator procurement process had not been completed.

Following the EB-2021-0110 settlement, key elements of program delivery were finalized, including the negotiation and execution of the System Integrator contract (covering meter and network deployment and program management scope), arbitration of the Purchased Service Agreement for meter deployment with the Power Workers' Union, and further refinement of project plans and requirements. As a result, cost forecasts were updated to reflect more mature program assumptions consistent with a progressing project lifecycle.

The current total forecast cost estimate reflects updated vendor pricing, refined planning assumptions, actual expenditures incurred from 2021 through 2025, forecast costs as of

September 2025, and the inclusion of capital expenditures associated with additional scope associated with the DIDA Phase 2 implementation. The forecast total cost estimate is classified as a Class 1 estimate, reflecting an advanced level of project definition and established execution plans, and is consistent with generally accepted cost estimating practices, which typically correspond to an expected accuracy range of approximately −10% to +15%. Notwithstanding the maturity of the project scope and execution approach, the Class 1 designation appropriately recognizes residual uncertainties inherent in large-scale meter deployment programs. Installation activities commenced in 2025, with fewer than 100,000 meters installed to end of 2025, and full deployment productivity has not yet been empirically demonstrated. Key uncertainties include, but are not limited to, variability in installation productivity as field operations scale; potential constraints related to customer access, appointment adherence, and scheduling efficiency; the frequency and scope of unanticipated electrical repairs or site readiness deficiencies identified during installation; and the operational complexity associated with coordinating multiple vendors, contractors, and concurrent workstreams across a broad service territory. As these factors continue to be resolved through execution, there remains a potential variance between estimated and actual costs. Accordingly, while the estimate is considered appropriate for the current stage of project development, actual costs may exceed current projections as deployment progresses and residual uncertainties are more fully realized.

Table 5 below compares the inflation adjusted EB-2021-0110 original total net cost forecast to the updated total net cost forecast.

Table 5 - EB-2021-0110 Plan Net Cost vs. Updated Net Cost Forecast for AMI 2.0 Project Execution

($M)	Total	Est Range
EB-2021-0110 Plan Net Cost*	705.6	599.8 – 846.7
Current Net Cost Forecast**	799.4	719.5 – 919.3

** The total in Plan Net Cost (705.6M) reflects an update to the original evidence in proceeding EB-2021-0110 that was escalated by 5.25% for inflation and escalated a further 1.3% consistent with Undertaking JTU-1.19 in EB-2021-0110, and excludes Peterborough and Orillia Rate Zones*
*** The Updated Net Cost Forecast includes the actual costs incurred through year-end 2025 for AMI 2.0 meter installation, 2026 – 2032 forecasts for AMI 2.0 meter installation, additional DIDA Phase 2 cost scope & Phase 3 DIDA forecast capital cost scope. This forecast excludes Peterborough and Orillia Rate Zones and the 2028-2032 DIDA Phase 3 prepaid expenditures related to cloud computing.*

Tables 6, 7, and 8 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's net capital expenditures for the 2023-2027 rate period and planned expenditures for the 2028-2032 rate period.

Table 6 - Hydro One - Investment Expenditures[13]

($M)	Plan[14] 23-27	Act/Fcst[15] 23-27	2028	2029	2030	2031	2032	2028-2032 Total
Gross Expenditures	581.0	558.0	213.5	60.2	7.1	3.8	2.5	287.1
Less Removals	0.0	11.2	5.6	1.9	0.0	0.0	0.0	7.5
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Expenditures	**581.0**	**546.9**	**207.9**	**58.4**	**7.1**	**3.8**	**2.5**	**279.7**

Table 7 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Expenditures	-	0.18	2.17	0.00	0.00	Embedded in Hydro One Networks		
Less Removals		0.01	0.13	0.00	0.00			
Less Contributions		0.00	0.00	0.00	0.00			
Net Expenditures		**0.18**	**2.04**	**0.00**	**0.00**			

[13] Figures presented in the tables may not sum to the totals shown due to rounding.
[14] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[15] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Table 8 - Peterborough RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Expenditures	-	0.00	5.53	0.00	0.00	Embedded in Hydro One Networks		
Less Removals		0.00	0.34	0.00	0.00			
Less Contributions		0.00	0.00	0.00	0.00			
Net Expenditures		**0.00**	**5.19**	**0.00**	**0.00**			

2023-2027 EXPENDITURES

The EB-2021-0110 AMI 2.0 project total net cost estimate, adjusted for inflation, was $705.6M, with an estimated range of $599.8M to $846.7M (−15 percent to +20 percent). The current Class 1 forecast total net cost estimate is $799.4M, $47.3M below the upper bound of the inflation adjusted total cost estimate of $846.7M and approximately $93.8M above the inflation adjusted EB-2021-0110 forecast of $705.6M. The current cost estimate reflects updated vendor pricing, more informed planning assumptions, actual costs incurred from 2023 through 2025, forecast costs as of September 2025, and the inclusion of additional scope associated with the DIDA Phase 2 implementation (see Section 2.5.3).

Importantly, as concluded in the AMI 2.0 Project Execution Review (see DSP Section 3.3, Attachment 3) the increases reflected in the current estimate to completion (ETC) are supported by clearly identified and explainable cost drivers that are generally consistent with industry experience for AMI programs of similar scale and complexity. Overall, E-Source found that Hydro One's forecasted capital cost performance remains directionally consistent with the market scan group of AMI programs when differences in program scope, operating conditions, and implementation complexity are considered.[16]

The key drivers of the cost variance relative to EB-2021-0110 settled amount are as follows:

- **Meter deployment costs:** The largest variance reflects meter deployment costs that were higher than originally estimated, as the initial estimate was developed in advance of the meter deployment RFP process and therefore relied on assumptions rather than market-validated pricing. The completion of the

[16] DSP Section 3.3, Attachment 3, p. 30.

post-settlement procurement process provided actual cost information, which indicated higher deployment costs than anticipated at the time of the EB-2021-0110 filing. In addition, the subsequent requirement to engage external warehousing and inventory management services - originally assumed to be provided internally - further contributed to this variance. The incremental cost impact associated with these factors is approximately $88.8M.

- **Solution integration, process development, and enablement:** The second variance reflects higher-than-estimated solution integration costs driven by greater-than-expected effort associated with developing and implementing business processes (including network design and installation, meter installation, and exception management), related training requirements, and the complexity of maintaining reliable billing during the transition from AMI 1.0 to AMI 2.0. This variance also reflects the unforeseen need to utilize the System Integrator's Work Management System, following an assessment that Hydro One's legacy WMS was not adequate to support the required work volumes and complexity. The incremental cost impact is approximately $25.3M.
- **Technical discovery and solution implementation:** The third largest variance reflects higher-than-estimated technical discovery and solution implementation costs, resulting from an underestimation of the complexity and associated level of effort required to integrate, scale, synchronize, and test multiple internal and external systems, including with the Meter Data Management Repository. The incremental cost impact is approximately $20.7M.
- **DIDA Phase 2 Implementation:** The addition of Distributed Intelligence (DI) Phase 2 Implementation scope (see Section 2.5.3) resulted in forecast costs totaling $8.0M.
- **Other variances:** Other smaller variances are attributable to underestimation of customer electrical repair costs and enhancements to customer communication processes, including advanced customer notification of meter replacements and the provision of appointment scheduling options.

The above increases were partially offset by reductions in material surcharge ($32.5M), overhead charges ($3.3M), and meter and network hardware costs ($14.0M).

Hydro One has implemented a range of targeted measures to contain AMI 2.0 meter and network costs while appropriately managing the risks associated with maintaining reliable and accurate customer billing. These measures reflect an active approach to cost control throughout program execution and include the following:

- **Fixed price contracting and competitive procurement:** Hydro One utilized fixed price agreements for meters and network equipment (hardware), meter and network deployment, and program management and integration services, thereby limiting exposure to cost escalation.
- **Robust financial and project governance:** The Project is being managed under a structured and comprehensive project management and governance framework that supports effective oversight, coordination, and delivery. Clear governance structures, roles, and accountabilities are in place, supported by regular project and leadership-level forums through which project status, issues, risks, and required decisions are reviewed and escalated, as appropriate, to the Project Management Leadership Team (PMOLT) and Steering Committee. The framework incorporates established project management practices, including the development and ongoing management of an Integrated Project Plan (IPP), coordination and tracking of deliverables across all workstreams, formal change control, quality assurance processes, and structured management of risks, assumptions, issues, decisions, and dependencies (RAIDD) through maintained logs and action registers. Deployment activities, testing and integration planning, and schedule sequencing are actively coordinated to support orderly execution and risk mitigation. In addition, the Project is subject to ongoing financial monitoring and reporting, including tracking of project costs and key financial metrics, enabling expenditures to be monitored against approved budgets and facilitating timely management response where variances or performance concerns are identified.
- **Use of standard IT solutions:** Where feasible, Hydro One adopted existing “out-of-the-box” information technology solutions rather than pursuing customized development, avoiding incremental costs and reducing implementation risk.
- **Optimized deployment resourcing:** Following arbitration of the Purchased Service Agreement, which required that 50% of meter installation work be

performed by internal resources, Hydro One implemented a resource cost-balancing strategy. Hydro One crews are deployed primarily in northern regions where internal delivery is more cost-effective, while outsourced resources are utilized in southern regions where third-party delivery offers lower unit costs.

- **Targeted use of third-party subcontractors:** Hydro One employed third-party subcontractors, rather than the meter vendor, for installation hardware such as equipment mounting brackets, resulting in avoided costs and total savings of approximately $4M.
- **Improved field execution efficiency:** Field productivity improvements have been implemented through practical execution innovations, including pre-assembly of access points and relays prior to shipment and design adjustments to simplify installation activities (e.g., hardware modifications that improve ease of handling in the field).
- **Pursuit of External Funding Opportunities:** To further mitigate cost impacts, Hydro One explored alternative funding opportunities and submitted an Expression of Interest to Natural Resources Canada under the Smart Renewables and Electrification Pathways (SREP) program. This application supported the use of Distributed Intelligence applications to modernize grid operations and advance energy transition objectives and was part of a broader collaboration with Alectra Utilities aimed at achieving cost efficiencies and shared learning. The application was not successful.

Table 9 below compares settled AMI 2.0 in-service additions values in proceeding EB-2021-0110 to actual/forecast in-service additions for 2023-2027.

Table 9 - EB-2021-0110 Settled In-Service Additions 2023-2027 vs. Actuals/Forecast

	2023	2024	2025	2026	2027	Total
Plan	32.4	69.5	158.4	158.9	161.8	581.0
Actual/Forecast	0	0	146.7	184.0	168.6	499.3

In-service additions for the 2023-2027 period are forecasted to be $499.3M, approximately $82M below the amount approved in EB-2021-0110. This forecast includes incremental costs associated with the DIDA Phase 2: Implementation scope, which were not contemplated in EB-2021-0110. The variance is primarily attributable to an approximate six-month lag between the installation of communication network equipment and its recognition as in service, as well as capital expenditures related to equipment removals that do not qualify for inclusion of in-service additions.

2028-2032 EXPENDITURES

Table 10 presents the forecast expenditures for the 2028-2032 period, organized by AMI 2.0 meter and network deployment activities, as well as DIDA Phase 3 realization and operationalization activities.

Table 10 - AMI 2.0 and DIDA Expenditures 2028-2032

($M)	2028	2029	2030	2031	2032	Total
AMI 2.0 Meter & Network Deployment	201.6	50.9	0.0	0.0	0.0	252.5
DIDA[17]	6.2	7.5	7.1	3.8	2.5	27.1
Hydro One Total	**207.9**	**58.4**	**7.1**	**3.8**	**2.5**	**279.7**
Orillia RZ Total	2.04	0.0	0.0	Embedded in Hydro One Networks		
Peterborough RZ Total	5.19	0.0	0.0			

AMI 2.0 meter and network deployment forecast expenditures for the 2028-2032 period, as described in Section 2.4, are estimated at $252.5M. Deployment activities are expected

[17] Prepaid cloud computing expenses for this investment are currently included in Hydro One's revenue requirement as capital expenditures. However, the resulting impact on the revenue requirement is not material. Hydro One will revise presentation of these costs within the revenue requirement as part of an evidence update, or at the Draft Rate Order stage of the proceeding.

to conclude in 2029; therefore, no forecast deployment expenditures are included beyond that year. DIDA forecast expenditures for the 2028-2032 period, as described in Section 2.5.4, are estimated at $27.1M. The above forecast costs are based on vendor contracts, Hydro One's meter installation labour rates, projected meter and network installation volumes, historical experience, and management's current assumptions regarding program execution.

5.0 ALTERNATIVES

EB-2021-0110 D-SR-12 compared three AMI 2.0 alternatives and recommended mass replacing the AMI 1.0 system with a competitively procured AMI 2.0 with modern functionality. Key features of the solution included meters incorporating additional computer power, measurement capability, and storage and a communication network with higher bandwidth supporting exponentially greater volumes of data. This alternative, among other things, provided customers with up-to-date AMI capabilities, and provided a platform to address future foreseeable needs and realize benefits over the 20-year service life of the investment. In this regard, the ability to enable DI was inherent in the original AMI 2.0 technology selection, as the necessary capital investment is embedded in the meters and the communications platforms themselves. Plans to enable modern capabilities (DI) would be executed using prudent stage gate/governance processes including stages for pilots and business case refinements. Upon completion of DI Phase 1 discovery/piloting/evaluation work in 2024-2025, two alternative Phase 2 DI Implementation pacing options were considered. Alternative 1 involved pausing Phase 2 implementation until the 2028-2032 investment cycle. Alternative 2 involved initiating Phase 2 implementation as early as reasonably possible.

ALTERNATIVE 1: PAUSING DI PHASE 2 IMPLEMENTATION UNTIL 2028 – 2032

Pausing DI Phase 2 Implementation until the 2028-2032 investment cycle, has the advantage of incurring less regulatory risk. However, it has several disadvantages including up to a four-year delay in realizing DI benefits, uncertain DI Application costing from the vendor in the future, and loss of the ability to take advantage of AMI 2.0 expertise as the AMI 2.0 project gets completed.

ALTERNATIVE 2: INITIATE IMPLEMENTATION OF DI PHASE 2 IN 2026 (RECOMMENDED)

Alternative 2 involved initiating Phase 2 DI Implementation in 2026. This alternative offered several advantages, including:

- Ensuring foundational DI IT infrastructure and DI applications were established as early as reasonably possible within the AMI 2.0 lifecycle, thereby positioning the platform to deliver value sooner;
- Driving near-term value by operationalizing prioritized foundational DI use cases, while preserving flexibility to implement additional use cases in response to evolving customer and system needs;
- Providing greater cost certainty through favourable vendor DI application terms secured through early engagement;
- Building organizational capability and operational readiness for DI at an early stage; and
- Leveraging AMI 2.0 program expertise and execution synergies while the AMI 2.0 program remained fully operational.

Alternative 2 has the disadvantage of requiring a change in the planned allocation of investments within the AMI 2.0 program during the 2023-2027 period. While Distributed Intelligence (DI) was always envisioned as a key component of the AMI 2.0 solution, it was intentionally excluded from the EB-2021-0110 cost estimates given then-prevailing uncertainties around cost, technical readiness, and integration complexity.

Alternative 2, initiating DI Implementation in 2026, was selected to enable earlier realization of value from the AMI 2.0 investment by activating foundational Distributed Intelligence (DI) capabilities as soon as reasonably possible within the AMI 2.0 lifecycle. Initiating Phase 2 DI implementation allowed Hydro One to begin operationalizing prioritized foundational DI use cases sooner, securing cost certainty through favourable vendor terms, and building organizational capability and operational readiness for DI at an early stage. This approach also preserved flexibility to expand functionality over time in response to evolving customer and system needs.

6.0 EXECUTION RISKS AND MITIGATION

Table 11 below provides a summary of AMI 2.0 related risks and mitigation strategies to address them.

Table 11 - AMI 2.0 Implementation Risks and Mitigation

Risk	Risk Mitigation
• Overall program execution risk	• The Program Management Organization (PMO) employs best practice methodology for assessing, prioritizing, and escalating issues to ensure timely resolution. The framework incorporates established project management practices, including the development and ongoing management of an Integrated Project Plan (IPP), coordination and tracking of deliverables across all workstreams, formal change control, quality assurance processes, and structured management of risks, assumptions, issues, decisions, and dependencies (RAIDD) through maintained logs and action registers.
• Missed meter readings and associated estimated bills/bill corrections during the transition from AMI 1.0 to AMI 2.0 as a result of potential network design issues.	• The program consists of discrete logical phases beginning with laboratory testing and the piloting of processes and equipment. • 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.
• There is a degree of planning uncertainty given mass network and meter deployment will be ongoing during the 2025/26 investment planning period. Additional learnings and material information about unit costs, project risks, and deployment strategies gained throughout 2025 and 2026 may result in on-going iterations to the investment plan.	• Monitor risks, issues, assumptions, and actions closely as part of governance structure. • Ongoing financial monitoring and reporting, including tracking of project costs and key financial metrics, enabling expenditures to be monitored against approved budgets and facilitating timely management response where variances or performance concerns are identified. • Ensure program cost estimates reflect the appropriate degree of uncertainty associated with stage in the meter and network deployment process (Class 1 estimate). Track and update cost

Risk	Risk Mitigation
	estimates based on meter and network deployment learnings.
• Workforce readiness in transition from vendor to Hydro One employees	• Involve Field Management in planning process. • Complete labour forecasting early, identify constraints, and plan resources accordingly. • Develop and implement standardized training plan • Evaluate work management tools and implement improvements as required
• 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.
• Residual risk of premature meter component failures as is the case with any electronic equipment.	• Meters warranted for 20-year service life • Due diligence performed on vendors through RFP process • New product testing and certification
• Availability of the vendor to manufacture and deliver AMI equipment in a timely manner	• Ensure plans address long lead time materials and monitor
• The project's scope, complexity, cost, and duration require sustained due diligence to ensure prudency.	• Conduct mid-term third party review to assess Hydro One's costs, schedule, and project management approach against peers.
• Materials procured for manufacturing vendor hardware are sourced globally may have ongoing supply chain issues and are potentially also subject to tariffs. This could impact project cost and/or delivery schedule.	• Monitor with hardware vendor

D-SR-13	DISTRIBUTION SPARE TRANSFORMER PURCHASE PROGRAM
Primary Trigger:	Asset Failure or High Risk of Failure
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	6.1	12.9	12.8	12.7	13.0	57.5
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This is a new investment that involves the procurement of strategic spare transformer inventory for distributing and regulating stations. The purpose of the investment is to ensure that Hydro One maintains an adequate and cost-effective inventory of transformers which enables the company's expedient replacement of failed or failing transformers at a distribution station. The inventory supports Hydro One's compliance with regulatory obligations while mitigating safety, system reliability, and environmental risks.

There are no planned capital expenditures for Orillia Rate Zone (RZ) or Peterborough RZ.

1.0 OVERVIEW

The Distribution Spare Transformer Purchase Program (Program) procures spare distribution transformers for distribution stations to ensure that the necessary inventory of transformers is available when needed to replace failed and failing transformers. Transformers are critical for maintaining reliability and safety. They comprise the single largest component of Hydro One's distribution station asset base. By procuring spare distribution transformers, the Program enables Hydro One to respond to emergencies created by failed or failing assets.

The Program's scope is limited to the cost of procuring the distribution transformers. Other costs, including the engineering design, construction and project management costs, and replacement of any other station components (such as protection, foundation or grounding) to complete the installation of the spare transformer are included in the Demand Emergency Capital Program (see DSP Section 3.11, D-SR-01).

Hydro One owns, maintains, and operates 1,009 distribution and regulating stations, with 1,228 distribution transformers. Each distribution station transformer supplies an average of 1,536 customers. Hydro One's distribution stations are primarily designed with one transformer. Most stations do not have an on-site spare transformer that can be switched into service in the event of failure. Typically, stations also have very little transfer capability based on the radial design of the distribution system.

If a distribution transformer fails or is at risk of imminent failure, it is critical for Hydro One to be able to perform the emergency replacement of that asset as soon as possible to maintain the integrity, safety and reliability of the distribution system. When distribution station transformers fail, customers experience an average service interruption of seven hours until a Mobile Unit Substation (MUS) is installed to temporarily restore customer load, or in the less common case, until load can be transferred. In addition to this reliability risk, failed transformers may pose safety and environmental risks. As a licensed distributor, Hydro One is obligated to comply with the planning, operating, and reliability criteria and standards administered by the Distribution System Code (DSC).

2.0 INVESTMENT NEED

The Program maintains the necessary inventory of spare transformers required to enable Hydro One's prompt replacement of failed transformers or transformers at imminent risk of failure. The Program contributes to Hydro One's sustainment of the operation of distribution stations and compliance with regulatory obligations mandated by the Ontario Energy Board DSC including Sections 4.1.1, 4.4.1, 4.4.5 and 4.5.6.

- Manage power quality of the distribution system in accordance with good utility practice (Section 4.1.1).
- Maintain the distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service (Section 4.4.1).
- Address any defects discovered during inspection activities within a reasonable period after discovery of the defect by planning repair activities or by performing any other action that is an affirmative response to discovery of the defect (Section 4.4.5).
- Develop and maintain appropriate emergency plans (Section 4.5.6).

The Program also mitigates safety, system reliability, and environmental risks associated with failed transformers.

Hydro One owns, maintains and operates 1,228 distribution station transformers (across the Hydro One, Orillia RZ and Peterborough RZ). Approximately 20% of the distribution station transformer condition assessments fall into the poor condition category. While the Distribution Station Refurbishment investment (DSP Section 3.11, D-SR-04) utilizes a planned approach to proactively replace poor condition distribution station transformers before failure, not all poor condition transformers will be replaced by the investment and it is likely that some transformers fail in-service due to unforeseen issues such as abnormal electrical events, extreme weather or rapid decline in transformer condition.

Certain failed transformers cannot be repaired and must be replaced with a new transformer. However, transformers cannot be procured reactively on an 'as-needed' basis. Procurement lead time has increased in recent years due to demand and is

currently 2.5 – 3 years. In 2019, transformer lead times were roughly 1.5 years. Therefore, maintaining an adequate supply of spare transformers is necessary to ensure that Hydro One has the transformers needed to restore service when failure occurs.

When a station transformer fails, service is initially restored with the installation of a MUS until a spare transformer can be transported and installed. It is not prudent for the purposes of correcting a failed transformer to deploy a MUS long-term because MUSs are in limited supply and are required for planned project and maintenance work. Planned transformer replacements under DSP Section 3.11, D-SR-04 and transformer corrective maintenance are both crucial to manage the population of high-risk station transformers in poor condition, and MUSs must be available to support this work. MUSs must also be available to support planned transformer replacements under DSP Section 3.11, D-SS-01 to enable system upgrades driven by load growth. The deferral of planned work contributes to the deterioration of asset condition and increased risk of asset failures, which negatively impact reliability and safety. An increase in transformer failures can result in MUSs being unavailable to support subsequent failures.

3.0 INVESTMENT DESCRIPTION

Spare transformers are used as replacements for failed units that cannot be repaired. They are also used as replacements for transformers that must be forced out-of-service due to escalated internal heating, partial discharge of energy within a transformer, or moisture in transformer windings, if not repairable.

The in-service population of 1,228 distribution station transformers comprises 41 unique categories. These transformers are categorized by MVA capacity, primary voltage, secondary voltage, step-down transformers versus voltage regulators, auto voltage regulation capability, three-phase versus one-phase and bushing style.

Hydro One takes an industry best practice approach and uses Markov models to plan the number of transformer spares required in inventory. The Markov models use inputs including:

- the in-service population of transformers per category;

- transformer failure rate for those which required replacement;
- time required to restore customer load following a transformer failure;
- time required to install a replacement transformer from inventory; and
- current transformer procurement lead time.

Based on these factors, the models determine the most cost-effective number of spares to be kept in inventory for each category of transformer used in the distribution system. Hydro One staff compare the number of spare transformers in inventory with the number of spares that should be in inventory as per the model to determine if there are any gaps. Hydro One has identified transformer inventory gaps for the 2028-2032 period which are to be addressed under this investment.

Modelling shows that of the 41 transformer categories:

- 31 categories currently have the required number of spare transformers.
- Seven categories currently have less than the required number of spare transformers.
- Three categories currently have more than the required number of spare transformers.

Firstly, the shortfall of nine transformers across seven categories will be addressed under this investment through the procurement of nine spare transformers during the 2028 – 2032 planning period.

Secondly, Hydro One plans to procure additional transformers under this investment to support forecasted failures during the 2028-2032 planning period. The failure rate of station transformers was on average 14 transformers per year from 2023-2025 (see DSP Section 3.2, Subsection 3.2.2.1). Of these 14 transformers, 10 were repairable and four required replacement. To address these failures, there has been an average spare transformer deployment of four units per year from 2023-2025. Based on this experience, Hydro One's assumption is that approximately 70% (10/14) of annual transformer failures can be corrected through repairs, and 30% (4/14) will require replacement during the planning period.

Thirdly, by 2028, there is projected to be approximately nine transformers in inventory that are above the modelled spare requirements across three transformer categories. This inventory will be maximized during the 2028-2032 planning period for planned project usage. Hydro One expects to deploy three of the nine transformers to planned projects under DSP Section 3.11, D-SR-04. Also, depending on which transformers fail during the 2028 – 2032 planning period, Hydro One may also be able to deploy spare transformers from this group to support failures under DSP Section 3.11, D-SR-01. Efficient use of inventory in this category group will decrease the volume of transformers to be procured under this investment (as described below).

In summary, Hydro One forecasts a total of 29 additional spare transformers will be required in inventory for the 2028-2032 period. This considers the current shortfall of nine transformers across seven categories and the expected spare deployment of four spare transformers annually to support failures (4 units x 5 years = 20 transformers over the five-year planning period). This inventory requirement is partially met by the deployment of three transformers from the group that has inventory above the modelled requirement across three transformer categories. Therefore, Hydro One plans to procure 26 spare distribution transformers under this investment during the 2028-2032 planning period to achieve the modelled level of transformer inventory required.

Procurement of the transformers under this investment will result in the total annual transformer inventory levels (i.e. inventory across all 41 transformer categories) shown in Table 1 below.

Table 1 - Spare Distribution Transformer Inventory Levels

	2028	2029	2030	2031	2032
Number of transformers procured under this investment	2	6	6	6	6
Expected number of spares deployed for failure replacement (DSP Section 3.11, D-SR-01)	4	4	4	4	4
Expected number of spares in current inventory deployed for planned replacement (DSP Section 3.11, D-SR-04)	0	0	1	1	1
Transformers in Inventory	64	66	67	68	69

The total number of transformers in inventory is based on a summation of the number of transformers in inventory for each of the 41 unique categories. When a transformer fails, a replacement spare transformer is selected based on primary system voltage, secondary system voltage, system voltage regulation requirement and customer loading. A spare transformer is only useful at a station if it can provide the right voltages, regulation, and loading. The Program investment is for the procurement of units needed to maintain the inventory levels necessary for the deployment of spares according to modelled transformer replacement volume projections over the 2028-2032 period.

4.0 OUTCOMES

The Investment aims to mitigate system reliability, safety, and environmental risks by allowing Hydro One to respond to emergency transformer failures as promptly as possible and restore the system to normal operating conditions. The Investment ensures compliance with Hydro One's regulatory obligations.

4.1 OEB RRF OUTCOMES

Table 2 below presents anticipated benefits from the investment in accordance with the Ontario Energy Board's Renewed Regulatory Framework:

Table 2 - Outcome Summary:

Customer Focus	• Improve customer satisfaction by minimizing interruptions and providing timely power restoration. • Reduce risk and severity of customer supply interruptions due to lack of operating spares.
Operational Effectiveness	• Maintain distribution system reliability and safety. • Reduce safety risks associated with failed equipment. • Minimize the utilization of MUSs for extended periods of time to support failures, thereby ensuring MUS availability to support the maintenance and capital work program.
Public Policy Responsiveness	• Ensure Hydro One meets its regulatory compliance obligations with respect to power system restoration and reactive response as per the Ontario Energy Board DSC Sections 4.1.1, 4.4.1, 4.4.5 and 4.5.6.

5.0 EXPENDITURE PLAN

Table 3 below summarizes Hydro One's aggregate planned and forecast net capital expenditures for the 2023-2027 rate period and the forecast net capital expenditures for the 2028-2032 planning period. There are no planned or forecasted net capital expenditures for Orillia RZ or Peterborough RZ.

Table 3 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	0.0	0.6	6.1	12.9	12.8	12.7	13.0	57.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**0.0**	**0.6**	**6.1**	**12.9**	**12.8**	**12.7**	**13.0**	**57.5**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be $0.6M. The forecast expenditures reflect progress payments to be made in 2027 for transformers procured in 2028.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are $57.5M. Hydro One plans to procure 26 spare transformers between 2028 – 2032.

The factors influencing the cost of the investment for the 2028-2032 period include:

- Manufacturer and material prices for transformers which have increased significantly compared to 2020 (Refer SPF Section 1.8 – Managing Market Cost Pressures);
- The cost of the spare transformer which is dependent on ratings such as MVA, primary voltage, secondary voltage, and voltage regulation capabilities; and
- The actual number of transformer failures and resulting replacement demand each year which determines the need for spare transformer deployment.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: REACTIVE PROCUREMENT

Alternative 1 is to deploy spare transformers currently in inventory without replenishing stock through planned procurement. Once the existing inventory is depleted, Hydro One would not maintain an inventory of spares and would procure replacement transformers only after a failure occurs.

This alternative is rejected because it would result in material negative impacts to reliability and safety by placing unsustainable strain on the Hydro One transformer inventory and MUS fleet. As described above, the current transformer inventory is below modelled levels

across multiple categories. Also, the current fleet of MUSs could not support this level of utilization. MUSs would be required to remain in service for extended periods of time until a replacement transformer could be purchased (2.5 – 3 years). This would hinder the MUS fleet's availability to support the planned maintenance and capital work program and to provide emergency power restoration for other system failures. In turn, deferring planned capital and maintenance work would result in increased asset failures. Execution of this strategy would result in there being no available spare transformers or MUSs to respond to failures resulting in customers without power for lengthy periods of time.

Under DSP Section 3.11, D-SR-02 Mobile Unit Substation Program, Hydro One plans to purchase new MUSs to replace retired MUSs, replace MUSs in poor condition, and purchase new MUSs to accomplish the planned capital work program. DSP Section 3.11, D-SR-02 does not include purchasing MUSs to enable transformer failure support over 2.5 – 3 year periods and also does not account for an increase in transformer failures.

ALTERNATIVE 2: MAINTAIN EXCESS INVENTORY

Alternative 2 is to maintain a higher inventory of spare transformers to meet a level of transformer failures that is above forecast. New spares would be procured based on additional conservative assumptions inputted into the Markov model. While this alternative would mitigate risks associated with increased failed and failing transformer volumes and transformer lead times, it is rejected because it would result in higher investment costs which would not be reasonably justified considering the probability of occurrence of these events.

ALTERNATIVE 3: STATUS QUO: MAINTAIN SUFFICIENT INVENTORY (RECOMMENDED)

Alternative 3 is to maintain a sufficient inventory of spare transformers to continuously address forecast transformer failures. New spares are procured based on Markov modelling results to replenish depleted inventory and meet system needs while mitigating over procurement and associated costs. This alternative is recommended as it addresses transformer failures in a timely manner and mitigates the negative impacts of overutilizing the MUS population.

7.0 EXECUTION RISK AND MITIGATION

The main execution risk is the availability of vendors to manufacture and deliver the spare transformers as needed. Manufacturer lead times are typically 2.5 - 3 years because of market demand, manufacturing timelines and supply chain constraints. This risk is mitigated by providing vendors with advanced transformer purchase forecasts to ensure that they will be able to accommodate Hydro One's demand.

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D-SR-14	SELECTIVE UNDERGROUNDING
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	17.6	19.4	20.2	21.1	22.0	100.3
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

The proposed investment is a targeted, risk-informed response to aging and deteriorating assets, increasing severe-weather exposure, material reliability impacts, and the structural limitations of Hydro One's predominantly overhead, radial distribution system. By undergrounding selected sections of overhead lines that already contains assets that require renewal and are located in off-road or densely vegetated areas with high customer consequences, the Selective Undergrounding program is expected to reduce customer outage impacts, shorten restoration times, and strengthen system resilience. The program proposes to selectively underground approximately 120 km of overhead line sections, with the higher-cost underground treatment applied only where the location-specific assessment supports undergrounding over feasible overhead alternatives. This measure targets undergrounding in locations where retaining an overhead configuration would leave a material residual reliability and resilience risk.

There are no planned capital expenditures for Orillia Rate Zone (RZ) or Peterborough RZ.

1.0 INVESTMENT NEED

Selective Undergrounding converts deteriorating and vulnerable sections of the overhead distribution system to underground. Hydro One's distribution system includes a limited number of overhead line sections where poor-condition assets requiring renewal coincide with elevated customer consequence and significant exposure to vegetation impacts, severe weather or difficult restoration conditions. At these locations, overhead-to-overhead renewal would address the asset condition needs but leave material reliability and resilience risks associated with continued overhead exposure unresolved. The program is focused on targeted overhead infrastructure that: (a) is in poor condition and requires renewal; and (b) is located in areas where continued overhead construction would retain material exposure to vegetation, severe weather or difficult restoration conditions and where an outage can result in significant customer impacts.

Hydro One operates a predominantly overhead distribution system that serves a vast, geographically dispersed customer base through a largely radial network. This configuration exposes overhead distribution assets to vegetation, wind, ice and other environmental conditions that contribute to customer interruptions and longer restoration times. Hydro One manages these risks through vegetation management (Exhibit E-03-02 Section 2.4), its Pole Sustainment program (DSP Section 3.11, D-SR-07), and its Distribution Line Sustainment program (DSP Section 3.11, D-SR-10).

Most overhead asset condition needs are addressed through these programs. Pole Sustainment addresses deteriorated poles through refurbishments, individual replacements, and clustered hardening using higher-strength poles. Distribution Line Sustainment addresses broader renewal needs, including relocating deteriorated off-road sections to road allowances to improve accessibility and restoration performance. These two programs remain the appropriate treatment for most poor-condition infrastructure because they address the underlying asset-condition need and, where applicable, improve structural strength and accessibility. At the same time, they retain an overhead configuration and leave renewed assets exposed to vegetation contact, falling trees, severe weather, and other environmental hazards. Accordingly, Selective Undergrounding

is reserved for a limited subset of locations where continued overhead construction would leave material residual reliability and resilience risk.

The materiality of this residual risk depends, in part, on the consequences of an outage at a specific location. Customer consequence is particularly important where poor-condition infrastructure is located on upstream sections of the distribution system, because an interruption can affect a disproportionately large number of downstream customers. This is especially relevant on Hydro One's largely radial distribution network, where interruptions on feeder-head sections have significantly greater customer impacts than interruptions elsewhere on the feeder.

Between 2021 and 2025, an interruption associated with a station interrupting device, representing the feeder-head section – the upstream section of a feeder between the station and the first interrupting device – resulted in approximately 1,900 customer-hours lost on average. By comparison, an interruption associated with a downstream line interrupting device resulted in approximately 244 customer-hours lost on average. As shown in Figure 1, feeder-head interruptions accounted for approximately 28 percent of the customer-hours reflected in this analysis.

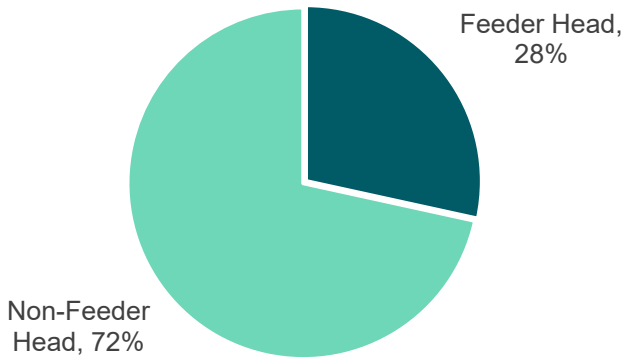


Figure 1: Breakdown of Interruptions on Feeder Head vs Non-Feeder Head (%)

These results demonstrate that an interruption of a relatively short upstream section can have a materially greater customer impact than failure elsewhere on the feeder. Undergrounding these relatively short feeder-head sections removes exposure to vegetation-related and overhead asset failure mechanisms and can provide substantial reliability and resilience benefits to large downstream customer populations without requiring conversion of the entire feeder.

High-consequence sections are not limited to feeder heads. Outages on other feeder sections farther downstream can also have significant consequences where they supply a substantial customer population, large commercial and industrial customers and other significant loads, have limited alternative supply capability, or otherwise form a critical section of the feeder.

The risk associated with a high-consequence section is greater where the same section is also materially exposed to overhead failure mechanisms or difficult restoration conditions. Portions of Hydro One's distribution system traverse heavily vegetated, rural and off-road corridors where tree contacts and adverse weather contribute to customer interruptions. During severe-weather events, trees and large limbs can fall from outside maintained vegetation clearances and damage poles, conductors and associated overhead equipment (see DSP Section 3.2). Access constraints significantly extend outage duration. Off-road or difficult-to-access sections require additional patrol time, damage assessment, vegetation clearing, crew mobilization, specialized equipment, and reconstruction before service can be restored. These conditions increase the operational consequence of retaining selected sections in an overhead configuration.

Hydro One’s distribution outage data confirms that these overhead failure mechanisms are material contributors to interruptions. Between 2021 and 2025, tree contacts were the leading cause of distribution interruptions, while equipment failures, including broken poles and crossarms, were the second most significant contributor. Together, these causes accounted for approximately 63% of interruptions between 2021 and 2025, as shown in Figure 2.

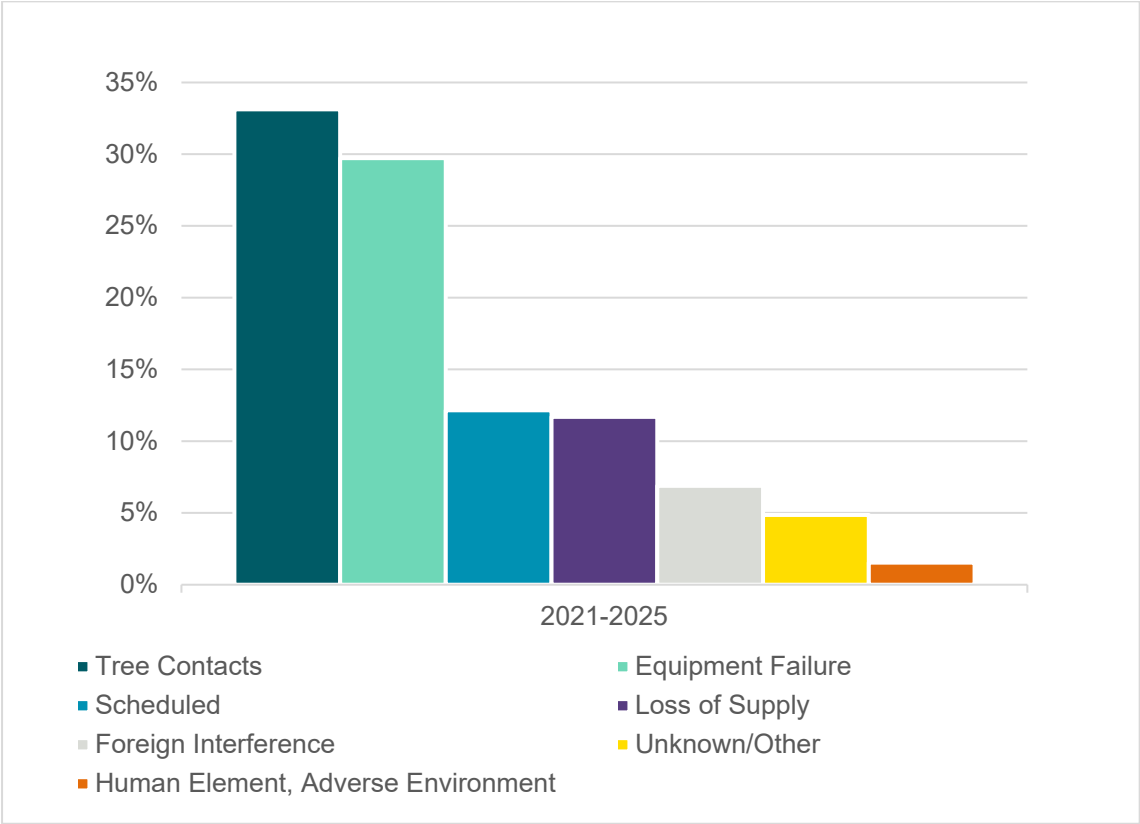


Figure 2: Breakdown of Interruptions by Category, Excluding Force Majeure Events, 2021-2025

Figure 3 below further demonstrates that between 2021 and 2025, equipment failures and tree contacts accounted for the vast majority of customer-hours lost from feeder-head interruptions. Because these failure mechanisms occur on high-consequence sections, a single outage can interrupt service to a large downstream customer population. The combination of significant downstream customer exposure and failure mechanisms associated with the overhead configuration can therefore result in disproportionately large reliability impacts.

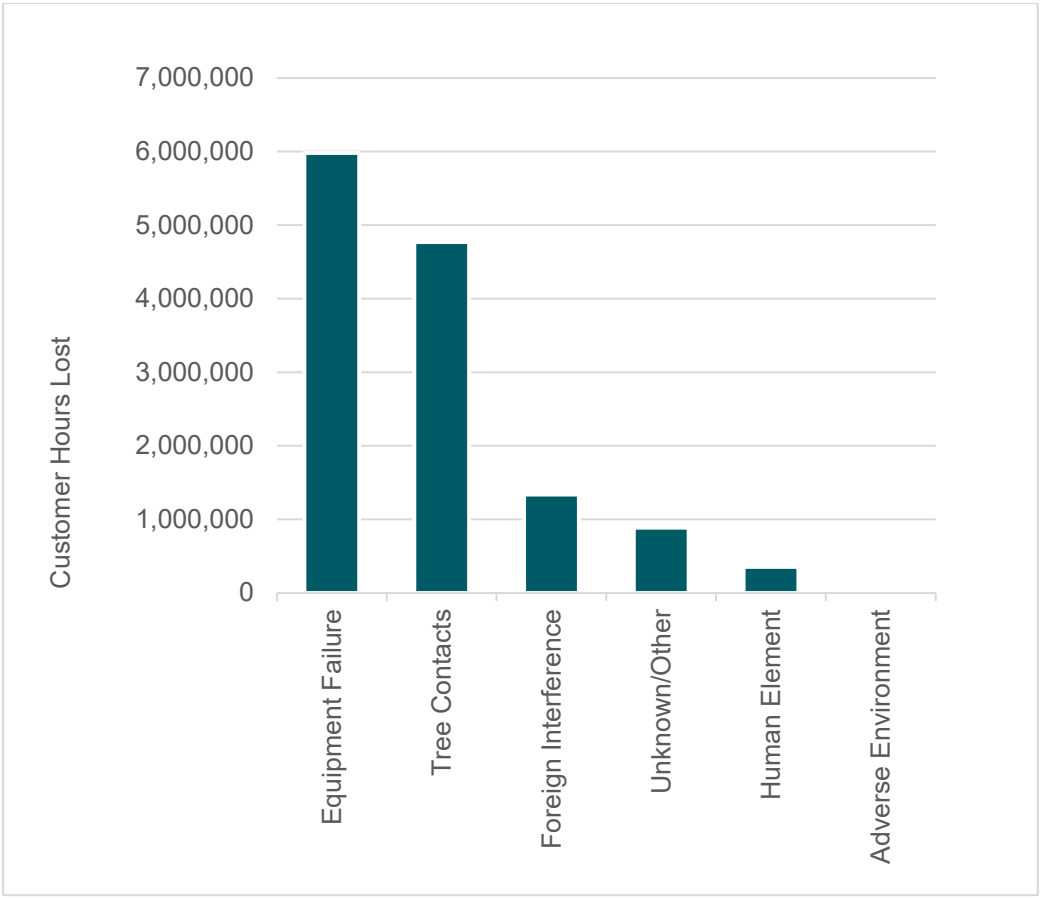


Figure 3: Feeder Head Customer Hours Lost by Cause Code Excluding Force Majeure Events, 2021-2025

Severe weather creates an additional source of exposure for Hydro One's overhead infrastructure. High winds and ice accretion can damage poles, conductors and associated equipment and result in extended customer interruptions. Hydro One's recent major storm experience demonstrates the physical and financial impact of these hazards on the overhead system.

The May 2022 derecho and March 2025 ice storm resulted in approximately $306M in net expenditures and approximately 73 million customer-hours of interruption over 2.1 million customer interruptions. These events also required the unplanned replacement of over 5,000 poles. The scale of pole replacement resulting from these events demonstrates the

direct exposure of overhead infrastructure to severe-weather damage and the resulting customer and restoration impacts.

Hydro One has also experienced a sustained increase in the number of Force Majeure (FM) and storm days. As shown in Figure 4 below, Hydro One experienced 62 FM and storm days in 2025, approximately 28% above the 10-year average (2015-2024) of 48.4 days. This trend increases the importance of considering severe-weather exposure when infrastructure on high-consequence sections requires renewal, since assets renewed in an overhead configuration will remain exposed to these hazards over their service life.

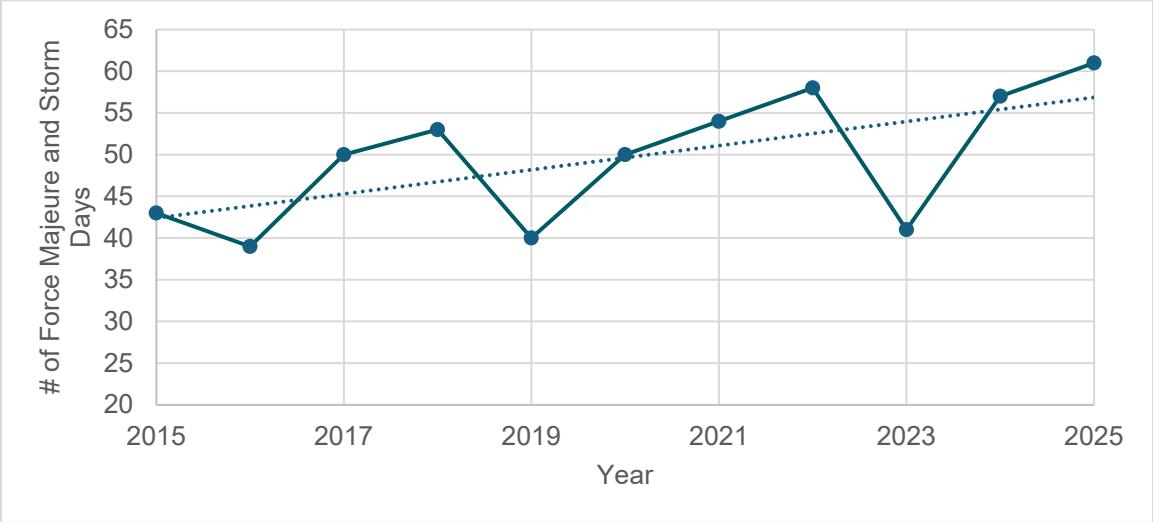
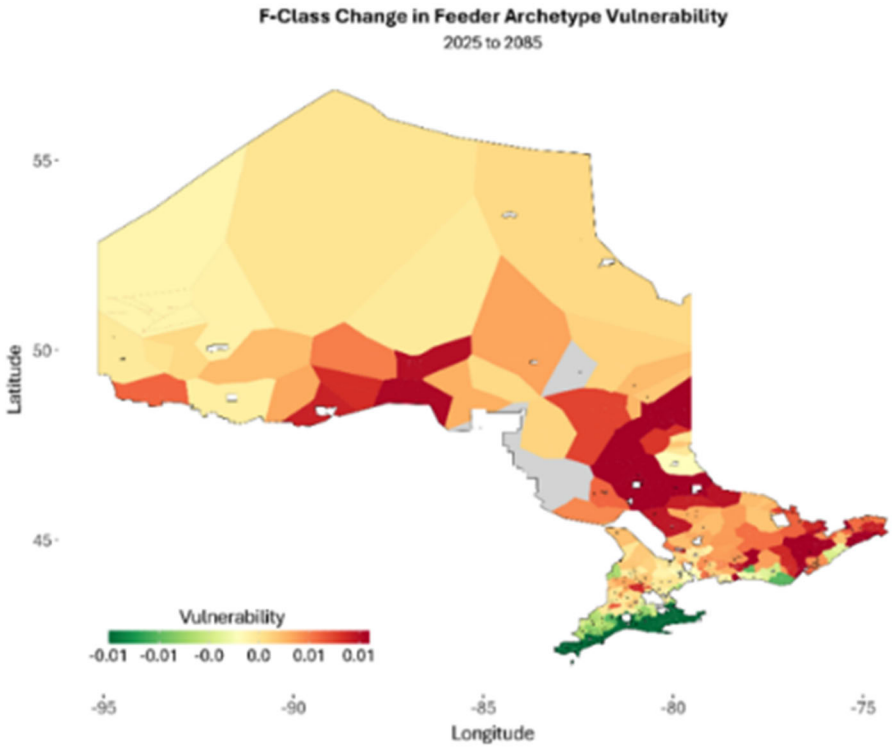


Figure 4: Storm and Force Majeure Days between 2015-2025

Hydro One's 2026 Vulnerability Assessment and Storm Hardening (VASH) analysis, described in DSP Section 3.6, subsection 3.6.6, provides additional forward-looking support for considering resilience in the treatment of these assets by assessing climate-related vulnerability over the period from 2025 to 2085.

Figure 5 illustrates the projected change in vulnerability of distribution (F-Class) and sub transmission (M-Class) feeders across Hydro One's distribution territory. The results demonstrate that climate vulnerability is not uniform across the system and that certain

feeders and geographic areas have greater exposure to projected wind and ice-accretion hazards.



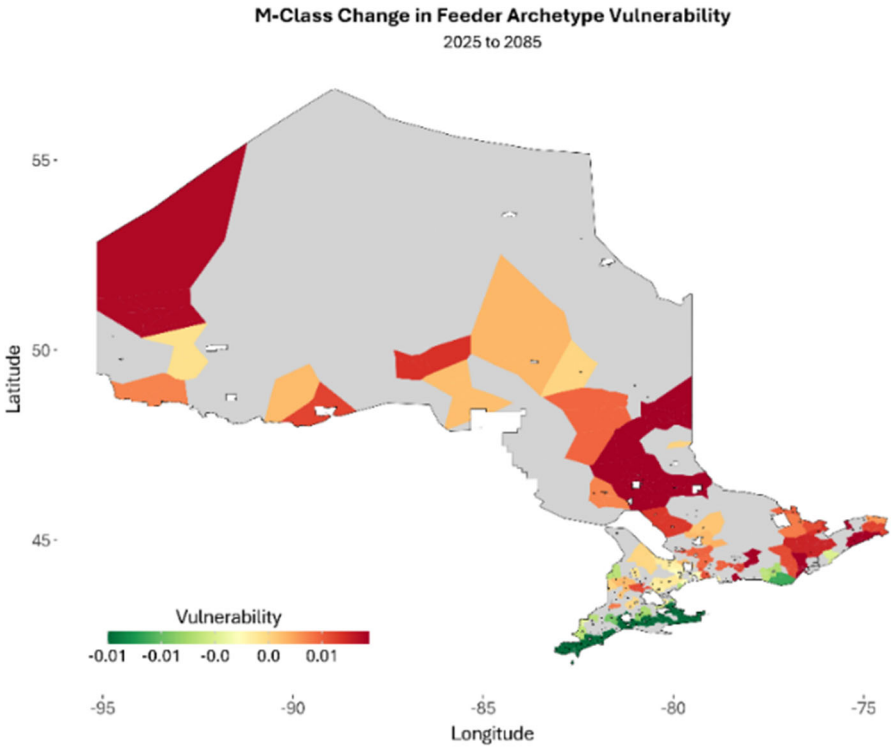


Figure 5: Change in Vulnerability for M-Class and F-Class Feeders from 2025-2085

The analysis also projects increasing vulnerability in parts of the near North, driven primarily by increasing ice accretion, and in Eastern Ontario, where the severity of both wind and ice accretion events is expected to increase over time. As a result, some overhead assets requiring renewal are projected to face greater severe-weather exposure over their service lives, supporting consideration of resilience alongside asset condition and reliability in investment planning.

Where poor-condition overhead line sections serve high-consequence areas and are materially exposed to vegetation, severe weather, or difficult restoration conditions, overhead-to-overhead renewal would not fully address the underlying reliability and resilience risk. Although overhead reconstruction would renew the asset condition, the renewed facilities would remain exposed to many of the same environmental and access-related failure mechanisms over their service lives. As customers and the provincial economy become increasingly dependent on reliable electricity service, and climate change contributes to more frequent and severe storms, the long-term exposure to these risks associated with retaining high-consequence feeder sections in overhead configuration has become an increasingly important consideration when determining the appropriate renewal treatment for these locations.

Selective Undergrounding addresses this need as a targeted component of Hydro One's integrated approach to strengthening the distribution system against increasingly severe operating conditions. The program is reserved for a limited subset of line sections where poor-condition assets requiring renewal coincide with elevated customer consequence, significant vegetation or severe-weather exposure, or difficult restoration conditions. In these circumstances, undergrounding provides a more appropriate long-term solution by addressing both the renewal need and the residual risks by eliminating exposure to key overhead failure mechanisms, reducing outage risk, improving restoration performance, and enhancing long-term service reliability and resilience for customers served through these critical locations.

2.0 INVESTMENT DESCRIPTION

Hydro One plans to selectively underground approximately 120 km of overhead feeder sections during the 2028-2032 period. This investment will convert selected sections of poor-condition overhead infrastructure requiring renewal to underground where the location-specific assessment supports undergrounding. Because these assets already require renewal, the investment addresses an existing need while removing the converted sections from the weather and vegetation hazards that disproportionately drive outages, reducing customer outage impacts and restoration times and strengthening system resilience.

Hydro One incorporated VASH as a forward-looking, system-level input to the identification and prioritization of selective undergrounding candidates. As described in DSP Section 3.6, 3.6.6, the VASH analysis assesses the relative vulnerability of Hydro One's overhead distribution system to projected high wind and ice-accretion hazards and combines this forward-looking information with historical Force Majeure outage experience and customer impact. Hydro One uses VASH results to identify feeders warranting further assessment and to consider the customer resilience value of potential system-hardening measures. Detailed feeder, section-level and engineering assessments are then used to determine whether Selective Undergrounding represents the appropriate renewal treatment for specific locations.

To translate these system-level resilience insights into specific investment opportunities, Hydro One has developed and is in the process of implementing a staged process to identify overhead line sections suitable for undergrounding. The process identifies priority feeders where asset condition, historical reliability, customer consequence and overhead exposure warrant further assessment, and then evaluates the specific sections within those feeders to determine whether selective undergrounding provides the appropriate treatment. Detailed engineering assessment will then confirm the sections that proceed to construction. The stages of this process are described below.

Priority Feeder Identification

Hydro One screens the distribution system to identify feeders with the greatest potential need for reliability and resilience intervention. For the 2028-2032 period, initial screening

identified priority feeders, representing approximately 975 km of overhead line. This feeder-level population provides a focused starting point for detailed section-level and engineering assessment. It does not mean that the complete feeder requires underground conversion. Within these priority feeders, Hydro One identifies specific candidate sections where the combination of existing asset condition, historical performance, system vulnerability and customer consequences indicate that a different replacement configuration may be warranted.

The feeder-level assessment considers:

- concentrations of poor-condition overhead assets requiring renewal;
- historical customer interruption impact, including SAIDI, SAIFI and customer-hours interrupted;
- downstream customers, critical loads and other consequences of an interruption;
- vegetation exposure and historical tree-contact performance;
- exposure to severe weather and other environmental hazards;
- system configuration, including M-Class circuits, feeder-head locations and available alternative supply;
- off-road or otherwise difficult-to-access construction and restoration conditions;
- historical and forward-looking severe weather vulnerability, including the results of VASH analysis regarding relative severe-weather vulnerability.

Hydro One will continue to apply the screening and prioritization methodology to reflect ongoing collection of inspection, condition, and system data during the 2028-2032 period, which may identify additional candidate feeders to be assessed during the rate period.

Identification of Candidate Sections

Within the priority feeders, Hydro One's process identifies specific overhead sections where concentrations of poor-condition overhead assets require renewal. These sections establish the potential Selective Undergrounding investment pool for more detailed assessment.

Hydro One then assesses the customer consequence and vulnerability of each overhead section. This step recognizes that the approximately 975 km of overhead line within the initial priority feeder population do not present the same level of asset condition, customer consequence, overhead exposure or restoration risk. Undergrounding is advanced only where the expected reliability and resilience benefits justify the investment.

As part of this assessment, particular consideration is given to sections with one or more of the following characteristics:

- **High downstream customer consequence.** This includes feeder heads and other upstream sections where failure can interrupt a substantial portion of the feeder.
- **M-Class or other significant supply function.** M-Class circuits may supply downstream distribution stations, large industrial and commercial customers or other significant loads.
- **Significant vegetation exposure.** This includes sections traversing dense forest or brush where historical tree contacts or surrounding vegetation create persistent overhead exposure.
- **Difficult restoration conditions.** Off-road sections or locations with constrained access can require additional patrol, vegetation clearing, specialized equipment and restoration effort following a failure.
- **Historical reliability exposure.** Hydro One considers the causes, frequency, duration and customer impacts of previous interruptions associated with the section.
- **Severe-weather vulnerability.** Hydro One considers both historical storm performance and the relative vulnerability identified through the VASH analysis.

Hydro One considers these characteristics collectively to determine whether continued overhead construction would sustain material reliability and resilience exposure after the underlying pole replacement need is addressed. Sections where the infrastructure will require renewal after considering customer impacts will proceed towards detailed engineering.

This approach also captures consequential sections located downstream of feeder heads. For example, a section farther downstream that supplies a material customer population while traversing a heavily vegetated, off-road corridor where conventional clustered hardening or relocation would continue to leave significant overhead exposure. Such sections warrant selective undergrounding where the same investment criteria are satisfied.

Detailed Engineering and Project Development

Following the identification of priority feeders and candidate sections, Hydro One will undertake a detailed engineering and location-specific project assessment to confirm the final scope of individual projects. Individual projects will proceed where the assessment confirms: (i) the section contains poor-condition overhead assets requiring renewal; (ii) the section exhibits sufficient customer consequence and vegetation, severe-weather or restoration exposure; and (iii) selective undergrounding provides a more prudent lifecycle solution than feasible overhead alternatives.

A detailed engineering and constructability review will confirm the final scope of individual projects while maintaining the program's established selection criteria and expenditure envelope, with the objective of undergrounding approximately 120 km during the rate period.

Illustrative Candidate Types

The following examples illustrate how Hydro One's selection framework applies to two types of locations identified within the priority feeder population.

<u>High Risk Area 1: Poor Condition Clusters in Vegetated and Off-Road Areas</u>

These areas have pole clusters located within dense vegetated and off-road areas. During storms, these sections can be exposed to tree-caused outages, pole failures and broken conductors, while access constraints can increase restoration complexity and duration.

Case 1– Midhurst TS M4

As an example, the Midhurst TS M4 sub-transmission feeder, located near Barrie, Ontario, is an M-Class feeder with approximately 40 km of overhead line. The feeder supplies approximately 3,000 customers and some of its overhead sections traverse off-road, densely vegetated areas, which can create significant access and restoration challenges during storm events. From a reliability perspective, the Midhurst TS M4 has accumulated over 2 million customer minutes interrupted due to tree-caused outages since 2021 which represents approximately 50% of the total feeder CMI (FM excluded).

Using the clustered approach, several concentrations of poor-condition poles have been identified in densely vegetated and off-road areas where access limitations can make restoration during storm events difficult, resulting in long interruptions. The 3 km cluster shown in Figure 6 is an example from the Midhurst TS M4 feeder, where multiple poor-condition poles are located in close proximity to one another (the "PN" labels indicate poles identified as potential replacement needs). In total, approximately 50 poor-condition poles have been identified within this cluster and are considered vulnerable to failure during severe weather events. An interruption within any section of this cluster has the potential to affect approximately 3,000 downstream customers. Figure 7 outlines a sample off-road section of this feeder that is prone to tree-caused outages.

By undergrounding the most vulnerable feeder sections within this cluster and eliminating the associated poor-condition poles, both the frequency of tree-caused interruptions and the risk of pole failures during severe weather events can be reduced. This targeted approach improves system resiliency, reduces exposure to high-impact outage events, and enhances reliability for a significant portion of customers supplied by the Midhurst TS M4 feeder.



Figure 6: Candidate Cluster - Midhurst TS M4, ~3,000 Customers, ~3 km

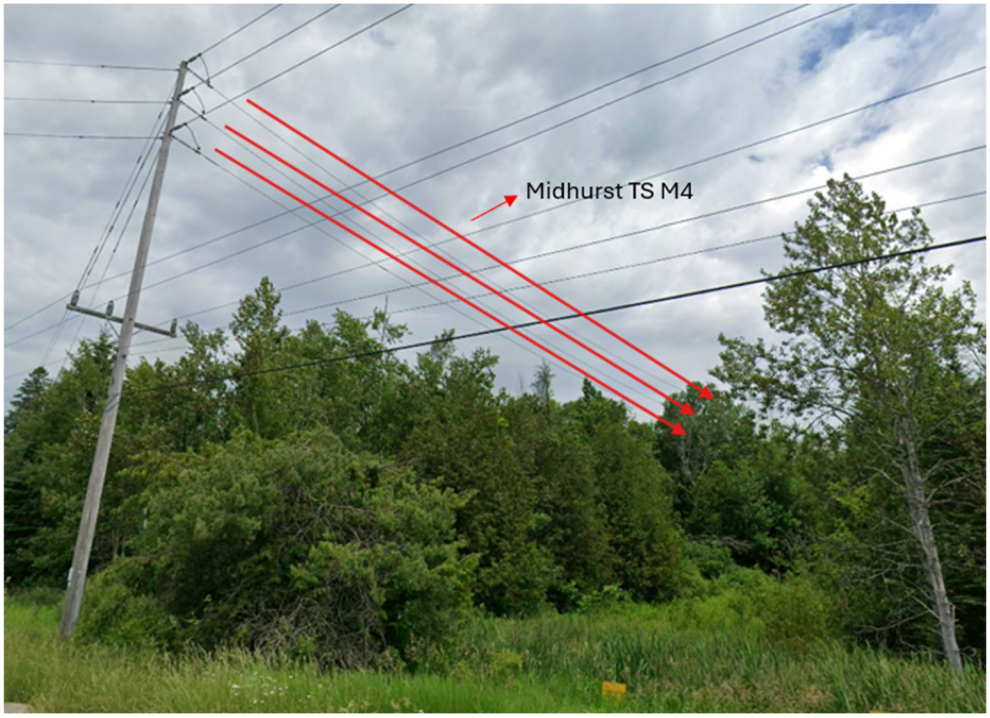


Figure 7: Beginning of Off-Road Overhead Section of Midhurst TS M4 near Candidate Cluster

<u>High Risk Area 2: Poor Condition Clusters with Large Downstream Impacts</u>

A second type of candidate occurs where concentrations of poor-condition assets are located on high-consequence upstream sections, including feeder heads and M-Class circuits. As described in the Investment Need, interruptions on these sections can result in materially greater customer consequences because a large downstream customer

population can remain dependent on the affected section. Where a high-consequence section also traverses dense vegetation or difficult-access terrain, rebuilding the section overhead may retain the same exposure that has contributed to historical interruptions.

Case 2 – Lindsay TS M4

Lindsay TS M4 is located in Central Ontario, north of Lindsay. This feeder is approximately 10 km long and has accumulated over 5 million customer minutes interrupted (CMI) due to interruptions since 2021. The majority of interruptions were recorded at the feeder head, and tree-caused interruptions accounted for approximately 50% of total CMI (FM excluded).

While the majority of this feeder runs along major roads, an approximately 500m section, shown in Figure 8 below, travels off-road through vegetation. Given the surrounding geography, any tree-caused interruption on this section will result in longer restoration times.

This section also contains approximately ten poor-condition poles that, due to their deteriorated structural condition, are more susceptible to failure during severe weather events. The combination of poor-condition assets, vegetation exposure, and difficult access conditions increases both outage risk and restoration complexity. Undergrounding this relatively short section therefore targets the portion of the feeder associated with the greatest reliability and resilience risk.

By undergrounding this section of the feeder, Hydro One can reduce exposure to tree-caused outages and eliminate the risk of failure associated with the existing poor-condition poles, thereby improving reliability and resilience in this area.



Figure 8: Section of Candidate Cluster – Lindsay TS M4, ~4700 Customers, ~0.5 km

Based on the screening and prioritization process described above, Hydro One identified an initial feeder population representing approximately 975 km of overhead line for further assessment. Hydro One plans to complete approximately 120 km of Selective Undergrounding during the 2028-2032 period. This scope reflects a measured implementation of a new targeted program. Not all sections within the initial feeder population are expected to qualify for undergrounding, and Hydro One may identify additional qualifying feeders and sections through continued application of the same screening criteria during the rate period. This approach maintains the program's focus on locations where poor-condition assets requiring renewal coincide with material customer consequences and residual overhead exposure, and where undergrounding is expected to provide the greatest value to customers.

3.0 OUTCOMES

Selective undergrounding improves reliability and resilience for customers supplied through the selected converted sections. The investment targets vulnerable overhead feeder sections where poor-condition assets, vegetation exposure, severe weather impacts, difficult access, and high customer consequence combine to create material outage and restoration risk.

By replacing selected overhead line sections with underground facilities, the program removes the converted poles and conductors from direct exposure to tree contacts, failing vegetation, wind, ice, and other overhead failure mechanisms. As a result, it is expected to reduce both vegetation-related outages and overhead infrastructure failures under normal operating conditions and during severe weather events.

The program is also expected to improve restoration performance during storm events. Many candidate sections are located in densely vegetated or off-road corridors where access constraints complicate patrol, damage assessment, vegetation clearing, repair activities, and reconstruction. By reducing the likelihood of storm-related overhead damage, undergrounding can reduce the need for resource-intensive restoration efforts in these difficult-to-access areas.

The program also supports Hydro One’s risk-based asset management approach by proactively addressing vulnerable infrastructure before failures occur. The cluster-based approach and section-level assessment enable targeted investments in locations where asset condition, reliability and resilience risks are most significant.

Overall, the Selective Undergrounding program is expected to renew poor-condition assets, strengthen system resilience, reduce the frequency and severity of high-impact customer interruptions, improve restoration performance, and deliver long-term reliability benefits to customers served by the most vulnerable sections of Hydro One's distribution system. These outcomes are consistent with the results of Hydro One's Vulnerability Assessment and System Hardening analysis, which evaluated Selective Undergrounding through a resilience benefit-cost analysis and produced benefit-cost ratios (BCRs) of approximately 0.49 for distribution (F-Class) feeders and 0.43 for sub-transmission (M-Class) feeders. The results demonstrate measurable customer value from reducing severe-weather outage impacts on overhead feeder sections.

The VASH results likely understate the value of Hydro One's section-level program because the analysis: (i) quantified Force Majeure resilience benefits only and did not quantify reliability benefits outside of Force Majeure events; and (ii) evaluated average candidate feeder segments rather than the highest-risk sections within individual feeders,

where targeted undergrounding is expected to provide greater value. Accordingly, the expected benefits of the Selective Undergrounding program extend beyond those quantified in the VASH analysis and are expected to provide significant reliability and resilience value to customers served by the more vulnerable sections of Hydro One's distribution system.

3.1 OEB RRF OUTCOMES

Table 1 below 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 caused by tree contacts and overhead equipment failure on sections converted to underground, under both normal and severe weather conditions, improving reliability for customers supplied through the selected sections.
Operational Effectiveness	• Avoid overhead failures and associated restoration efforts on sections converted to underground, particularly during severe weather events, and improve restoration performance in off-road and densely vegetated areas by reducing the need for overhead repair and restoration costs. • Reduce vegetation management requirements associated with the undergrounded sections.
Public Policy Responsiveness	• Strengthen system resiliency by hardening targeted feeder sections on vulnerable feeders, aligned with Hydro One's VASH analysis and the OEB's Distribution Sector Resiliency, Responsiveness and Cost Efficiency initiative to address challenges posed by climate change.

4.0 EXPENDITURE PLAN

Table 2 below summarizes Hydro One's aggregate planned and forecast net capital expenditures for the 2028-2032 planning period. There are no planned or forecasted net capital expenditures for Orillia RZ or Peterborough RZ.

Table 2 - Hydro One - Investment Expenditures

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	20.0	22.0	23.0	24.0	25.0	114.0
Less Removals	2.4	2.6	2.8	2.9	3.0	13.7
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**17.6**	**19.4**	**20.2**	**21.1**	**22.0**	**100.3**

2023-2027 EXPENDITURES

There are no planned or forecast expenditures for this investment over the 2023-2027 rate period. DSP Section 3.11, D-SR-14 is a new investment program commencing in 2028.

2028-2032 EXPENDITURES

Hydro One plans to selectively underground approximately 120 km of overhead lines during the 2028-2032 planning period. This scope reflects a measured implementation approach that focuses on the sections where the location-specific assessment supports undergrounding over feasible overhead alternatives. The proposed pacing averages approximately 24 km sections of overhead feeders to convert to underground per year over the rate period. In establishing the program scope, Hydro One identified a sizeable potential candidate pool that met the investment criteria, including poor-condition assets requiring renewal, feeders with exposure to severe weather, and off-road sections that would require long system restoration post outage. Hydro One developed the capital expenditure forecast by applying costs derived from comparable undergrounding projects to the planned scope. Hydro One also considered that selective undergrounding is generally a higher-cost treatment upfront than conventional overhead renewal and a new program will benefit from execution experience gained over time. Accordingly, Hydro One adopted a measured implementation approach that balances customer support for investment to improve day-to-day reliability and resilience to severe weather with customer affordability considerations.

5.0 ALTERNATIVES

Hydro One considered the practical alternatives available to address concentrations of poor-condition overhead infrastructure at the locations identified through the Selective Undergrounding screening process. Because the underlying assets require renewal, the alternative assessments therefore address how the identified sections should be renewed and whether the additional reliability and resilience benefits of removing the section from the overhead environment justify the incremental cost of undergrounding.

ALTERNATIVE 1: CONTINUE EXISTING PROGRAMS / STATUS QUO

Under this alternative, the poor-condition assets identified within the candidate sections would continue to be addressed through Hydro One's existing pole sustainment approach, by replacing poor-condition poles like for like.

This alternative generally has a lower initial cost than undergrounding and remains appropriate for many overhead renewal needs. It addresses the underlying asset-condition requirement by replacing deteriorated assets while generally retaining the existing overhead configuration and route. However, for locations considered under Selective Undergrounding, like-for-like overhead renewal would retain renewed assets in an overhead configuration and therefore maintain exposure to vegetation contact, falling trees, and severe-weather damage. In overhead sections where these risks remain material due to customer consequence, vegetation density, system configuration or restoration challenges, a like-for-like overhead renewal would not address the full investment need. Accordingly, while this alternative remains appropriate for many overhead renewal needs, it was not selected as the optimal solution for selective undergrounding locations.

ALTERNATIVE 2: ENHANCED OVERHEAD SYSTEM HARDENING OR RELOCATION

Hydro One also considered whether enhanced overhead measures could sufficiently mitigate the identified risks without undergrounding. Depending on the location, these measures can include covered conductor, clustered pole hardening, and relocation of off-road sections to road allowance.

These measures can provide meaningful benefits and remain appropriate in many locations. Relocation can improve accessibility, reduce restoration duration and, depending on the route, reduce vegetation exposure. Clustered pole hardening replaces concentrations of poor-condition poles within common feeder sections and installs stronger poles to improve structural resilience. Covered conductor can mitigate certain tree-caused interruptions relating to vegetation contacts on the conductor.

However, these treatments retain an overhead asset configuration which is exposed to vegetation and severe weather. Relocation reduces off-road access challenges but may not provide an effective alternative where suitable roadside routing is unavailable or where the relocated line would remain materially exposed to vegetation and weather. Clustered pole hardening improves the structural integrity of the overhead system, but hardened poles constructed in densely vegetated corridors remain exposed to falling trees and other severe-weather-related hazards that can result in conductor damage or vegetation-related outages.

Hydro One therefore uses these enhanced overhead measures where they adequately mitigate the identified risk. Where those measures would leave material residual and resilience risk would not adequately address the full investment need, Selective undergrounding is preferred.

ALTERNATIVE 3: BROADER OR FULL-FEEDER UNDERGROUNDING

Hydro One considered a broader application of undergrounding, including conversion of longer portions or complete priority feeders.

This alternative would remove a greater length of line from overhead vegetation and severe-weather exposure and could provide additional reliability and resilience benefits. However, it would require substantially greater capital investment and would extend underground construction into portions of feeders where the customer consequence, asset-renewal requirement or residual overhead risk does not support the higher-cost treatment.

This alternative was not selected because it would not provide the same level of investment targeting and would result in undergrounding sections for which lower-cost overhead renewal remains appropriate. The proposed selective approach captures the benefit of removing the most consequential and vulnerable sections from overhead exposure without incurring the cost of converting complete feeders.

ALTERNATIVE 4: SELECTIVE UNDERGROUNDING (RECOMMENDED)

Under the recommended alternative, Hydro One will underground only the specific portions of priority feeders where concentrations of poor-condition assets requiring renewal coincide with high customer consequence and material overhead exposure, and where the location-specific alternatives assessment supports underground construction.

Selective undergrounding addresses the underlying renewal need while removing the converted section from vegetation-contact and overhead structural failure mechanisms. It is particularly applicable where poor-condition assets coincide with significant customer consequence, vegetation exposure, severe-weather vulnerability, or difficult restoration conditions, and where retaining an overhead configuration would leave material residual reliability and resilience risks.

This alternative is recommended because it targets undergrounding at feeder sections where it is expected to provide the greatest reliability and resilience value to customers. It maintains Hydro One's existing overhead sustainment programs as the primary treatment for most renewal needs and applies the underground renewal configuration only where the section-level assessment determines that feasible overhead renewal, or hardening measures would leave material residual reliability or resilience risk and would not adequately address the full investment need.

6.0 EXECUTION RISK AND MITIGATION

In developing the selective undergrounding program, Hydro One considered factors such as material availability, outage coordination, fleet and equipment requirements, and site-specific construction conditions. These considerations informed the proposed scope and

pacing of the investment and support Hydro One's readiness to safely and efficiently execute the program throughout the rate period.

Material Availability

The selective undergrounding program is dependent on the availability of underground cable, hardware, and other associated distribution equipment. Delays in material availability or extended manufacturing lead times could impact construction schedules and program execution. Hydro One mitigates these risks through established supply chain management practices, including advance procurement planning, strategic inventory management, supplier performance monitoring, and ongoing assessment of material availability.

Fleet and Equipment Availability

Delivery of the selective undergrounding program requires access to specialized construction equipment and fleet resources. Distribution works closely with Fleet Services to forecast equipment requirements and align fleet availability with planned work volumes. Equipment utilization and fleet requirements are continuously monitored to support efficient deployment of fleet resources. Where required, external rental options are available to supplement fleet capacity and support program execution.

Site Conditions, Access, and Permitting

Selective undergrounding work is performed across Hydro One's service territory, which includes urban, rural, remote, off-road, and environmentally sensitive locations. Construction activities may be influenced by site-specific conditions such as rock excavation requirements, seasonal access restrictions, and challenging terrain. Hydro One incorporates these considerations into project planning and scheduling activities to support efficient execution. Construction activities are sequenced, where practical, to take advantage of favourable seasonal conditions and improve access to challenging locations. Further discussion of these delivery factors is provided in DSP Section 3.10.

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D-SR-15	UNDERGROUND CABLE REPLACEMENT AND REJUVENATION PROGRAM
Primary Trigger:	Asset Condition and Failure Risk
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	47.6	49.9	63.3	87.5	89.2	337.5
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This investment will replace or rejuvenate approximately 750km of deteriorated underground cable between 2028 and 2032. Cable segments will be selected based on reliability performance, asset age, failure history, customer impact, and diagnostic testing results.

Historically, underground cables were managed on a run-to-failure basis because failures were relatively infrequent. However, underground cable interruptions have increased by approximately 60% on an average annual basis, driven by an aging population of direct-buried assets and growth in Hydro One's underground cable network.

The proposed program will address high-risk underground cable segments through either cable rejuvenation or replacement before failures occur. Compared to a reactive approach, the program is expected to reduce repeat interruptions, improve customer reliability, lower emergency restoration requirements, and minimize the disruption associated with repeated excavation and splice repairs.

There are no planned capital expenditures for Orillia Rate Zone (RZ) or Peterborough RZ.

1.0 INVESTMENT NEED

Hydro One's distribution system contains approximately 7,300km of underground feeder, which represents approximately 12,000 linear km of underground cable, as of year-end 2025. Since 2016, Hydro One's underground cable network has grown by over 30%, primarily due to LDC acquisitions and new load connections. Over the same period, interruptions resulting from underground cable failures have increased by approximately 60% on an average annual basis, as aging and deteriorating direct-buried cable assets have become a more significant contributor to customer reliability impacts.

Underground cables are primarily used to supply residential customers residing in urban areas. A significant portion of the underground cable population is "direct-buried", meaning that it was originally installed by laying cable in a trench, without the protection of ducts or other protective conduits. At the time that much of Hydro One's underground cable was installed, direct-buried installations were common practice. Direct-buried cables lack physical and mechanical protection which impacts their performance and makes them more susceptible to faults. Over time, moisture and electric stress can penetrate cables that do not have strand-block technology resulting in water trees which weaken the cables' insulation, resulting in unpredictable faults.

Historically, Hydro One ran underground cables to failure because unplanned interruptions were relatively infrequent and their customer impact was low. Under this approach, Hydro One generally addressed failures through splicing and localized replacement of failed sections, with broader segment replacement undertaken selectively where localized repairs would not reasonably address the performance of the affected cable segment. However, as underground cables have aged, their performance has deteriorated, causing repeated, localized outages in certain areas of the province that are increasingly disruptive to customers. With the population of aging and deteriorated underground cable continuing to grow, a reactive approach is no longer effective or sustainable.

Compared with the historical average from 2016 to 2020, the frequency of unplanned interruptions caused by underground cable failures increased by approximately 60% over the 2021 to 2025 period (see Figure 10), with an average duration of 7 hours. Failing to

address the deteriorating condition of legacy direct-buried cables in a timely manner will eventually lead to even more frequent faults, subjecting customers to multiple sustained interruptions. Without a planned remediation strategy, approximately 43% of underground cables within Hydro One's distribution system will be beyond their expected service life (ESL) of 30 years by 2032.

As seen from Figures 1 through 4, the impact of deteriorated underground cable is significant, resulting in recurring, disruptive restoration work in customers' neighborhoods. Underground cable failures are particularly disruptive because repairs require excavation to expose and access the failed section. These activities frequently affect roads, lawns, landscaping, tree roots, and nearby utilities, creating significant inconvenience for customers and communities.

While splice repairs can restore service, they do not address deterioration along the remaining length of the cable. As a result, customers can experience repeat failures on the same cable segment, leading to additional excavation activities, repeated outages, and increasing restoration costs over time.



Figure 1: Disruption to Other Utilities: Splice Installation with a Telecom Cable (outlined in red) above an Underground Cable



Figure 2: Environmental Impact: Exposed Tree Roots during Cable Splice Installation



Figure 3: Customer Impact: Remediated Land After Cable Splice Installation



Figure 4: Customer Impact: Open Pit in Front of Customer's Lawn

Specific operational centers in Hydro One's territory have experienced a high number of interruptions due to underground cable failures. As seen in Figure 5 below, Newmarket, Lincoln, Orleans, Bolton, and Essex have experienced high levels of customer hours lost due to unplanned underground cable interruptions. Throughout this document, these five areas will be referred to as the "focus areas".

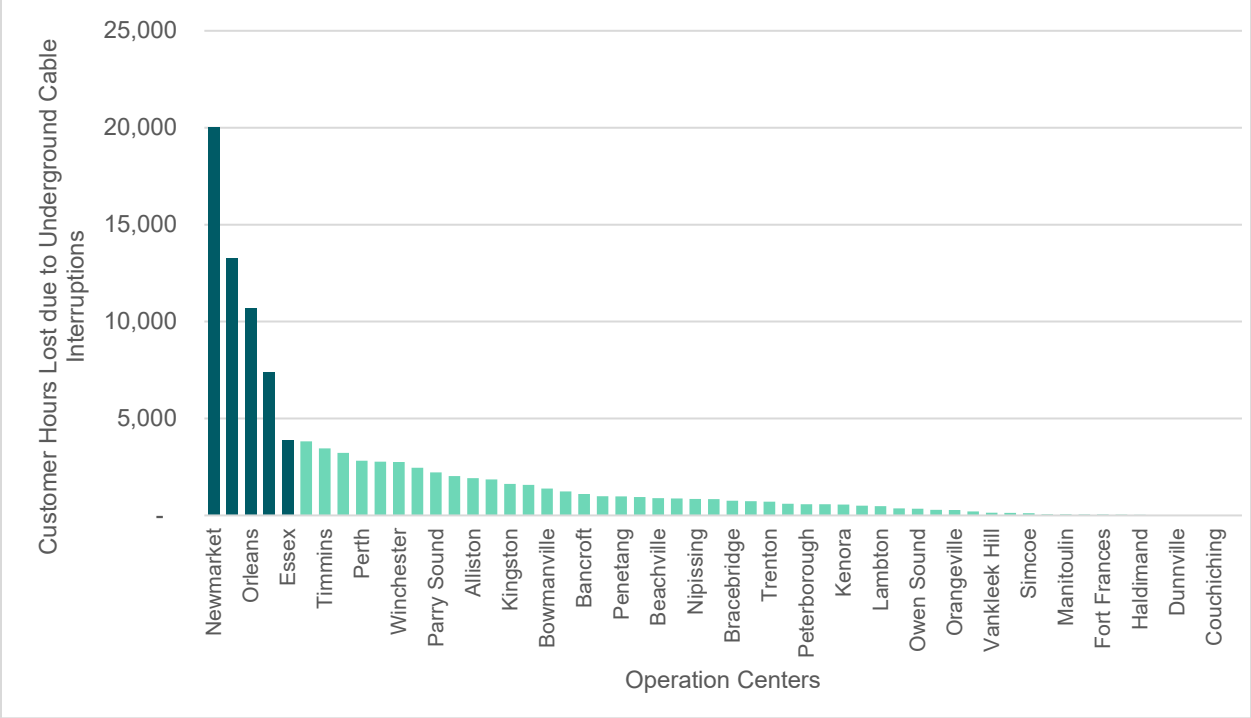


Figure 5: Operational Centers with most Customer Hours Impacted due to Underground Cable Interruptions caused by Equipment Failure, Force Majeure Events Excluded, 2020 to 2025

Hydro One identified the focus areas as the priority locations for investment in underground cable renewal, based on a combination of customer hours interrupted, interruption frequency, asset age profile, concentration of direct-buried assets, known repeat-failure locations, and restoration complexity. Together, these areas represent Hydro One's highest concentration of underground cable reliability risk and are the initial priority for planned remediation activities.

Hydro One assumes a 30-year ESL for direct buried primary cross-linked polyethylene (XLPE) underground cables. As noted previously, Hydro One historically adopted a run-to-failure approach for its underground cables. Using this analysis, on average, approximately 30% of the primary underground cable infrastructure in these areas will be beyond their ESL of 30 years in 2028, as seen in Figure 6 below. This concentration of aging assets, combined with historical reliability performance and customer impacts, indicates that these areas present elevated risk relative to the broader system. In this Figure, *Cable Segment* refers to the total length of an underground cable from one termination to the other.

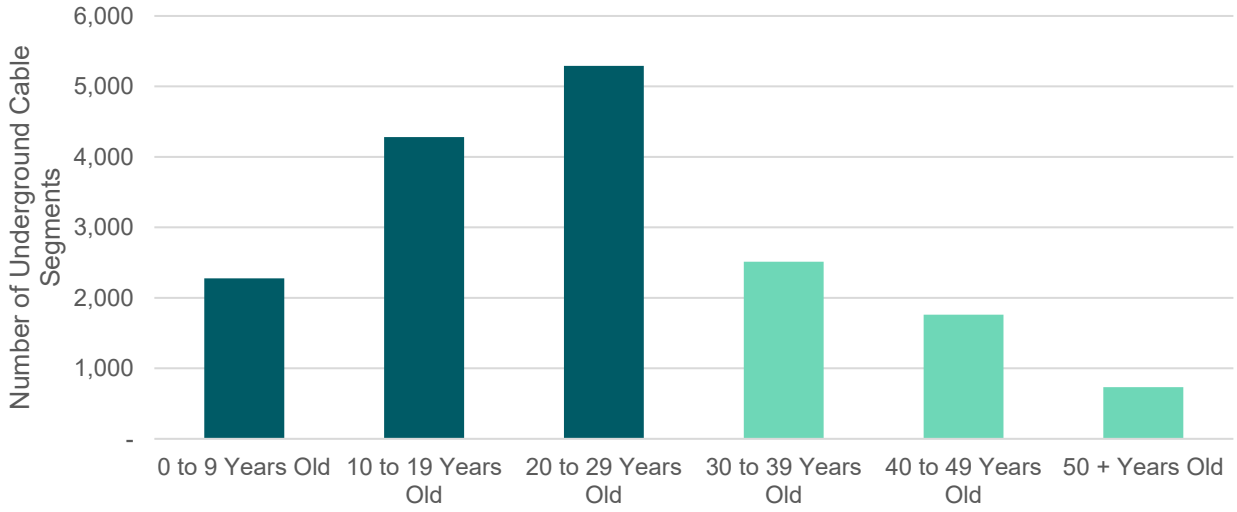


Figure 6: Age Demographic of Underground Cables in Focus Areas (Newmarket – Stouffville, Orleans, Bolton, Essex, Lincoln)

The majority of the older cables in these focus areas are direct-buried or were installed using non-Hydro One standards (particularly in areas acquired from other LDCs, such as Bolton and Stouffville), and some areas lack back-feed capability to allow for faster power restoration during interruptions. A subdivision in Stouffville, Ontario, for example, has experienced several long-duration outages since 2020, averaging 13 hours per outage. The underground infrastructure in this area was acquired from a local utility, was not built to Hydro One standards, and is approximately 55 years old. In addition, this area has very limited back-feed capability, which makes restoring power extremely difficult. Lincoln has

experienced the second-highest customer hours lost due to underground cable failures, primarily on sub-transmission M-class circuits.

Like Newmarket, Bolton and Orleans have several areas, primarily subdivisions, that are experiencing poor underground cable reliability due to old direct buried cables, and installations that are not built to Hydro One standards since they were acquired from other LDCs. In most cases, installations that are not up to Hydro One standards increase the complexity of repair and replacement work (as seen in Figures 7 through 9), as equipment connected to the underground cable (such as padmount transformers and switches) must also be addressed to ensure the overall design meets current Hydro One standards. In addition, Essex has averaged 10 interruptions per year since 2020 due to underground cable failures, with some interruptions occurring on the same feeders. This repeat-failure pattern indicates that reactive repairs are not fully addressing the underlying deterioration in affected cable segments.

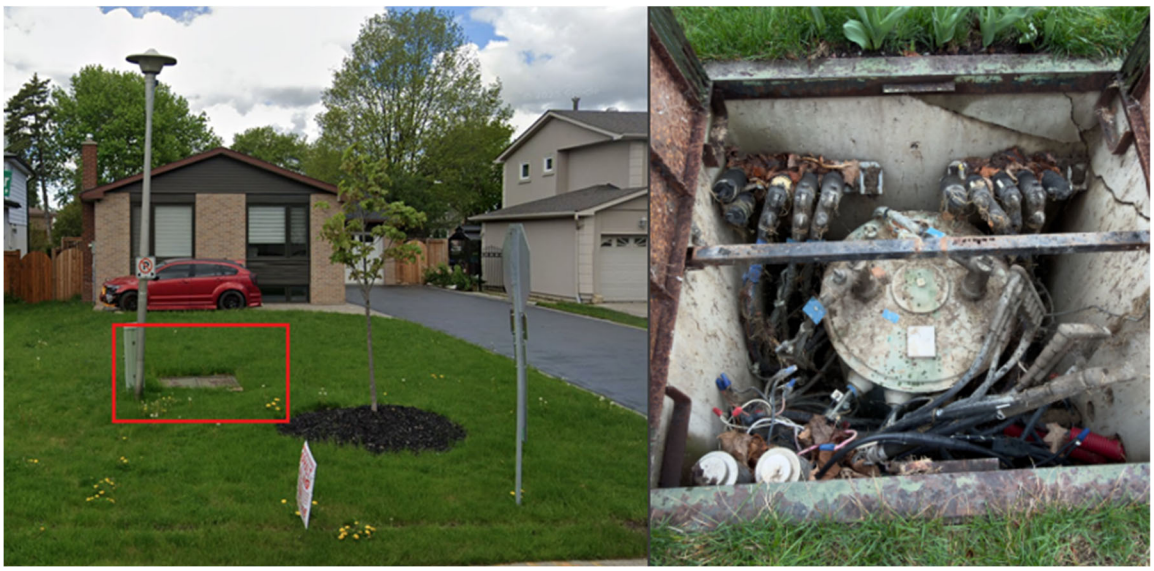


Figure 7: Submersible Transformer Installation on Customer's Front Lawn – Acquired LDC (Bolton)



Figure 8: Submersible Switch Installation in Customer's Yard – Acquired LDC (Bolton)



Figure 9: Unjacketed Underground Cables in Bolton, Ontario

Figure 10 below shows the sustained increase in underground cable interruptions over time, consistent with the aging profile of the direct-buried cable population.

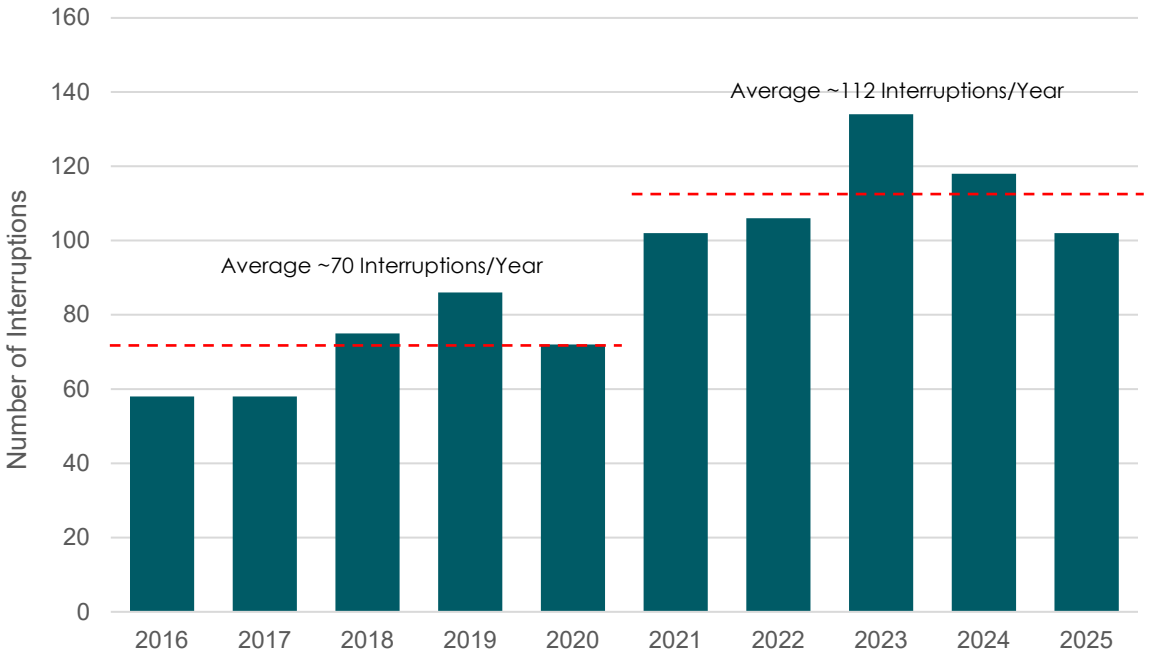


Figure 10: Number of Underground Cable Interruptions due to Equipment Failure, Force Majeure Excluded

Further, by replacing direct-buried underground cables with newer XLPE cables installed in duct, the proposed investment will reduce the number of dig-in interruptions, which have contributed to Hydro One's reliability challenges. The number of dig-ins that resulted in unplanned customer interruptions almost doubled during 2021 to 2025 compared with 2016 to 2020, as shown in Figure 11 below. On average, interruptions resulting from dig-ins caused 4-hour customer outages.

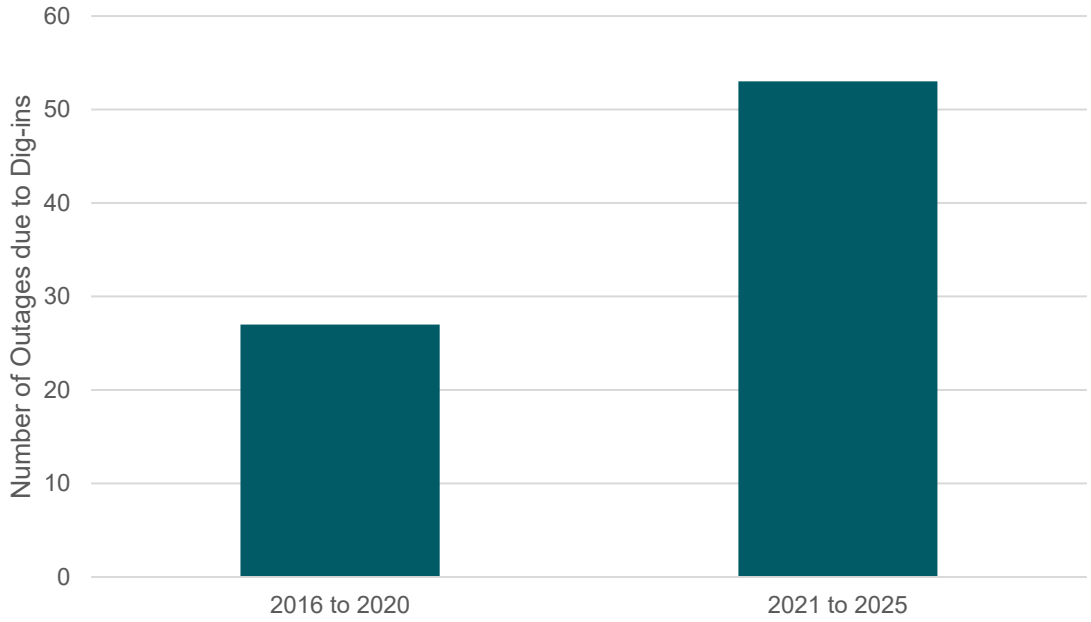


Figure 11: Number of Interruptions due to Dig-ins, Force Majeure Excluded

The spending under the Distribution Lines Trouble Call and Storm Damage Response Program (DSP Section 3.11, D-SR-05) has seen an overall increase since 2016, as seen in Figure 12. Under this program, underground cable sections that are experiencing repetitive faults are either replaced with new sections of cable or spliced. This trend correlates with the increasing number of unplanned underground cable interruptions depicted in Figure 10 above. The reliability of direct-buried cables decreases with age as the cable insulation becomes increasingly susceptible to water treeing. Water trees develop when moisture ingress and electrical stress interact within the insulation, forming microscopic defects that progressively degrade its dielectric strength. As these defects grow, the likelihood of insulation failure and cable faults increases. Consequently, without a planned remediation strategy, aging direct-buried cable systems are expected to experience a higher rate of unplanned interruptions due to the long-term degradation of underground cable insulation associated with this installation method.

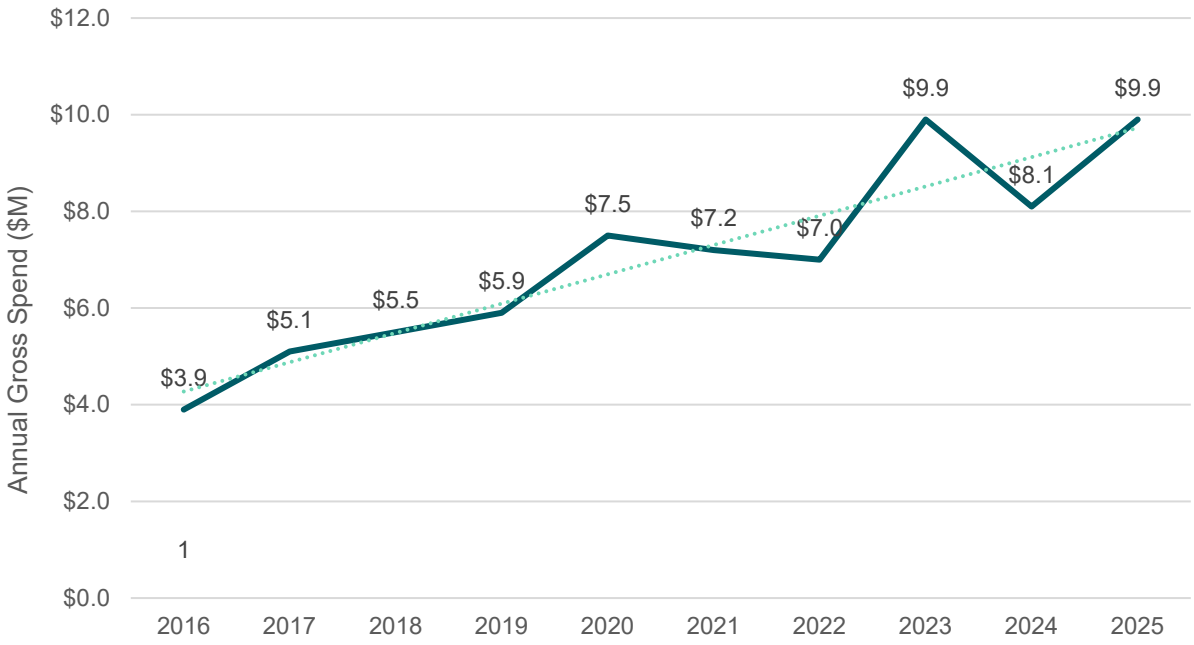


Figure 12: Annual Gross Spend ($M) Under Trouble Program, D-SR-05

Together, the increase in underground cable interruptions, dig-ins, and trouble program expenditures demonstrates that reliance on a reactive maintenance model is creating growing reliability and cost pressures. As the underground cable population continues to age, these pressures are expected to increase without a planned remediation strategy.

From an efficiency perspective, planned repair or replacement of underground cables required approximately 70% fewer interruption hours than unplanned work. On average, approximately 7 hours were accumulated per unplanned interruption to repair an underground cable compared to 1.7 hours under a planned interruption. Similarly for replacement, approximately 7 hours were accumulated per unplanned interruption to replace an underground cable compared to 2.6 hours under a planned interruption.

Therefore, having a planned underground cable replacement program will allow Hydro One to reduce the number of unplanned interruptions by addressing poor condition cables before they fail, make repairs and replacements more cost-effective and efficient, and reduce service disruptions to customers.

2.0 INVESTMENT DESCRIPTION

Hydro One plans to address approximately 750km of deteriorated underground cable through rejuvenation (500km) or replacement (250km) over the planning period. Historically, underground cables were managed on a run-to-failure basis because failures were relatively infrequent. However, underground cable interruptions have increased by approximately 60% on an average annual basis, driven by an aging population of direct-buried assets and growth in Hydro One's underground cable network. This investment represents a transition from a reactive strategy to a planned, risk-based asset management approach. The planned approach consists of a combination of rejuvenating existing cable through injection of new insulating material and where necessary, replacement of cable segments that cannot practically be rejuvenated.

Without a planned investment, deteriorated underground cables would continue to be addressed on a reactive basis following failure. Because restoration activities require fault location, excavation, assessment, and repair or replacement of the failed section, this would result in lengthy outages and significant disruption to surrounding communities.

A planned underground cable replacement and rejuvenation program is prudent and more efficient relative to a reactive approach. Considering the increasing length of the Hydro One underground cable network and the increase in underground cable interruptions, a planned program will allow Hydro One to better address these assets before they fail, leading to fewer interruptions to customers. A planned approach by targeting underground cables based on condition and reliability metrics will improve system reliability and customer experience while allowing work to be scheduled efficiently.

While a reactive approach was appropriate when failure rates were relatively low, this approach has become less effective as the underground cable population ages and deteriorates. Repairing individual failures addresses only specific fault locations and does not mitigate the residual failure risk associated with the remaining cable. As a result, deteriorated cable segments often experience repeat failures, additional outages, and increasing restoration requirements over time.

Considering underground cables have been managed using a run-to-failure strategy, there is limited condition data for existing underground cables in the focus areas. The underground cable replacement and rejuvenation program will be supplemented via the Underground Cable Diagnostic Program outlined in Exhibit E-03-02, Subsection 2.2.4.

The underground cable segments within the priority focus areas identified above will be prioritized using historical reliability performance, failure history, customer impact, age, installation characteristics, and system configuration. While diagnostic testing will ultimately determine the appropriate treatment strategy for individual cable segments (as shown in Figure 13 as an example), the proposed program scope was developed using multiple risk indicators, including customer hours interrupted, failure frequency, asset age, installation type, historical reliability performance, and restoration complexity. Together, these indicators demonstrate an elevated risk profile that supports planned intervention before widespread failures occur. The cable rejuvenation and replacement strategies are described below.

Cable Rejuvenation

Cable rejuvenation consists of refurbishing cables with insulation degradation due to water trees. Water trees are small voids in cable 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 silicon-based liquid insulating material into both ends of the cable (seen in Figure 14 below). This liquid fills in the gaps between each conductor strand and eventually diffuses into the insulation to fill water tree voids. Where the assets allow it, rejuvenation is typically a more cost-effective, less disruptive means of renewing deteriorated underground cable. However, as noted below, not all cables are candidates for rejuvenation, either because they are too severely deteriorated or because the design of certain cable vintages is not suited to the technique.

Hydro One introduced a cable injection pilot program in 2018. Since then, Hydro One has completed cable injection projects in the Orleans area in 2024 and 2025 and will continue in 2026 and 2027. In 2025, the cable injection initiative resulted in approximately $20M in productivity savings compared to traditional replacement. These savings demonstrate the potential for cable rejuvenation to manage reliability risk at a substantially lower cost and

with significantly less customer disruption than conventional replacement activities. In contrast to the traditional method of digging up direct-buried cables to perform replacements, cable injection provides minimal disruption to the physical surface above a cable, as the fluid is injected from one cable termination point to the next.

Based on industry experience, cable injection can be expected to increase the useful life of cables by 20 to 25 years, providing an economical alternative to replacing direct-buried cables. Building on the pilot program, Hydro One proposes to continue cable injection across its service territory over the plan period.



Figure 13: TDR Testing Prior to Cable Injection in Orleans, Ontario

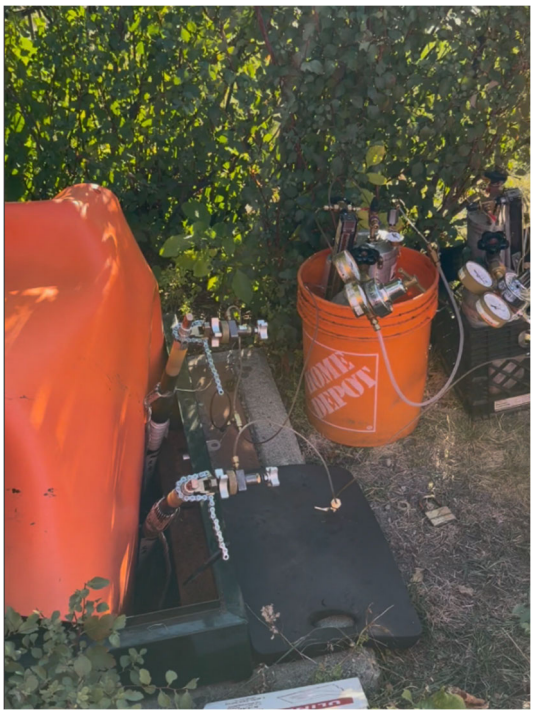


Figure 14: Underground Cables being Injected in Orleans, Ontario

Not all underground cables are suitable candidates for rejuvenation. Certain cable designs, including strand-blocked XLPE cables widely installed beginning in the early 1990s, are incompatible with current injection technologies. In addition, severely degraded concentric neutral condition, excessive existing splices, and certain installation configurations may preclude rejuvenation. Where these conditions exist, cable replacement will be required.

Cable Replacement

In areas where cable replacement is necessary for the reasons described above, Hydro One will replace direct-buried cables (seen in Figure 15) with newer XLPE cables installed in polyvinyl chloride (PVC) conduit (seen in Figure 16). For high-load areas such as major road intersections and highways, new underground cables can be installed in concrete-encased ducts to provide additional mechanical protection.

In 2015, Hydro One formally adopted an “all-in-duct” approach by updating its underground cable installation standards to require the use of conduits for new installations. Installing new underground cables in conduit and concrete encased ducts

will provide greater flexibility for the maintenance and future replacement of these cables. In addition, installing in conduit or duct will greatly increase the longevity of these cables and prevent physical damage caused by moisture intrusion, which is one of the most common causes for premature failure of direct-buried cables.



Figure 15: Direct Buried Underground Cables



Figure 16: Underground Cables in PVC Conduit/Duct

3.0 OUTCOMES

This investment is expected to address deteriorating underground cables in Newmarket (Stouffville area), Essex, Bolton, Lincoln, and Orleans. Over the 2020 to 2025 period, the focus areas have experienced approximately 22 million customer minutes interrupted (CMI) due to underground cable failures.

Compared to the status quo run-to-failure approach, the proposed program is expected to:

- Reduce the frequency of unplanned underground cable interruptions in the identified focus areas;
- Reduce repeat interruptions experienced by customers served from deteriorated cable segments;
- Reduce emergency excavation, repair, and restoration activities;
- Reduce reliance on temporary splice repairs;
- Reduce restoration durations associated with underground cable failures; and
- Improve overall customer experience by addressing deteriorated assets before failure occurs.

Planned underground cable replacement will replace direct-buried cables with modern XLPE using PVC conduits or ducts, improving maintenance, reliability, and longevity. Cable rejuvenation will extend the service life of eligible underground cables at a much lower cost than full replacement, improving reliability for cables that are eligible.

3.1 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	• Improve reliability for customers served from deteriorated underground cable infrastructure by reducing repeat outages, prolonged restoration events, and localized service interruptions in the highest-risk areas of the distribution system.
Operational Effectiveness	• Transition underground cable management from reactive-response activities to planned, condition-based asset management, enabling more efficient scheduling, improved resource utilization, reduced emergency restoration requirements, and optimized asset life-cycle management. • Installing new underground cables with modern materials and in conduit will improve reliability and longevity. Installing in conduit will also make future replacements more efficient and reduce outage times for repair and maintenance.

4.0 EXPENDITURE PLAN

Table 2 below provides the planned and actual or forecast expenditures for the overall cable replacement and rejuvenation program. Tables 3 and 4 provide a breakdown of planned and actual or forecast expenditures by program.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total
Gross Investment Expenditures	0.0	2.6	52.0	54.6	69.7	97.2	99.1	372.6
Less Removals	0.0	0.0	4.4	4.7	6.5	9.7	9.9	35.2
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**0.0**	**2.6**	**47.6**	**49.9**	**63.3**	**87.5**	**89.2**	**337.5**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Table 3 - Cable Replacement Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Investment Expenditures	0.0	0.0	36.7	39.0	53.8	80.9	82.6	293.1
Less Removals	0.0	0.0	4.4	4.7	6.5	9.7	9.9	35.2
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**0.0**	**0.0**	**32.3**	**34.3**	**47.3**	**71.2**	**72.7**	**257.9**

Table 4 - Cable Rejuvenation Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total
Gross Investment Expenditures	0.0	2.6	15.3	15.6	15.9	16.2	16.6	79.6
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**0.0**	**2.6**	**15.3**	**15.6**	**15.9**	**16.2**	**16.6**	**79.6**

2023-2027 EXPENDITURES

As outlined in DSP Section 3.11, D-SR-10, the investments related to cable rejuvenation moved from the Distribution Lines Sustainment Initiatives Program (DSP Section 3.11, D-SR-10) to DSP Section 3.11, D-SR-15 to harmonize all activities related to underground cable renewal. The forecast expenditures for the 2023–2027 period in Table 4 represent trailing costs associated with work completed in 2027. Cable Replacement is a new program with no expenditures during the 2023–2027 period.

2028-2032 EXPENDITURES

Tables 2 through 4 set out the planned expenditures for underground cable rejuvenation and replacement over the 2028–2032 planning period. Hydro One proposes to expand the underground cable rejuvenation program and introduce an underground cable replacement program during 2028–2032 to address the system needs outlined in Section 1.0 above. During this period, Hydro One plans to address approximately 750km of underground cable, consisting of approximately 500km of rejuvenation and 250km of replacement. The scope is expected to substantially renew deteriorated underground

cable infrastructure in the five focus areas: Essex, Newmarket, Orleans, Lincoln, and Bolton. The scope by focus area is shown in Figure 17.

Candidate cable segments will be prioritized using historical reliability performance, including interruption frequency and duration, repeat failures, customer impact, cable age, cable design and installation type, available condition information, system configuration, and the availability of back-feed capability. This screening process will be used to develop and sequence annual work plans within the focus areas.

Diagnostic testing under the Underground Cable Diagnostic Program described in Exhibit E-03-02, Subsection 2.2.4, will then be used to confirm cable condition and select the appropriate treatment for each candidate segment. Rejuvenation will be used where testing confirms that the cable is technically eligible and can achieve the required life extension. Replacement will be undertaken where the cable is not eligible for rejuvenation because of its condition, design, number of existing splices, installation configuration, or other technical constraints.

The expenditure plan assumes that approximately two-thirds of identified cable segments will be suitable for rejuvenation and one-third will require replacement. This assumption is informed by Hydro One's recent injection experience, asset demographics, installation characteristics, and industry experience regarding treatment eligibility. Actual work volumes will be refined as diagnostic testing results become available.

The expenditure profile reflects a phased ramp-up of activities over the planning period, particularly cable replacement work. This pacing allows Hydro One to incorporate early diagnostic results, refine work packages, confirm the appropriate rejuvenation and replacement mix, and scale the internal and external execution capacity required to support larger replacement volumes in the later years of the plan.

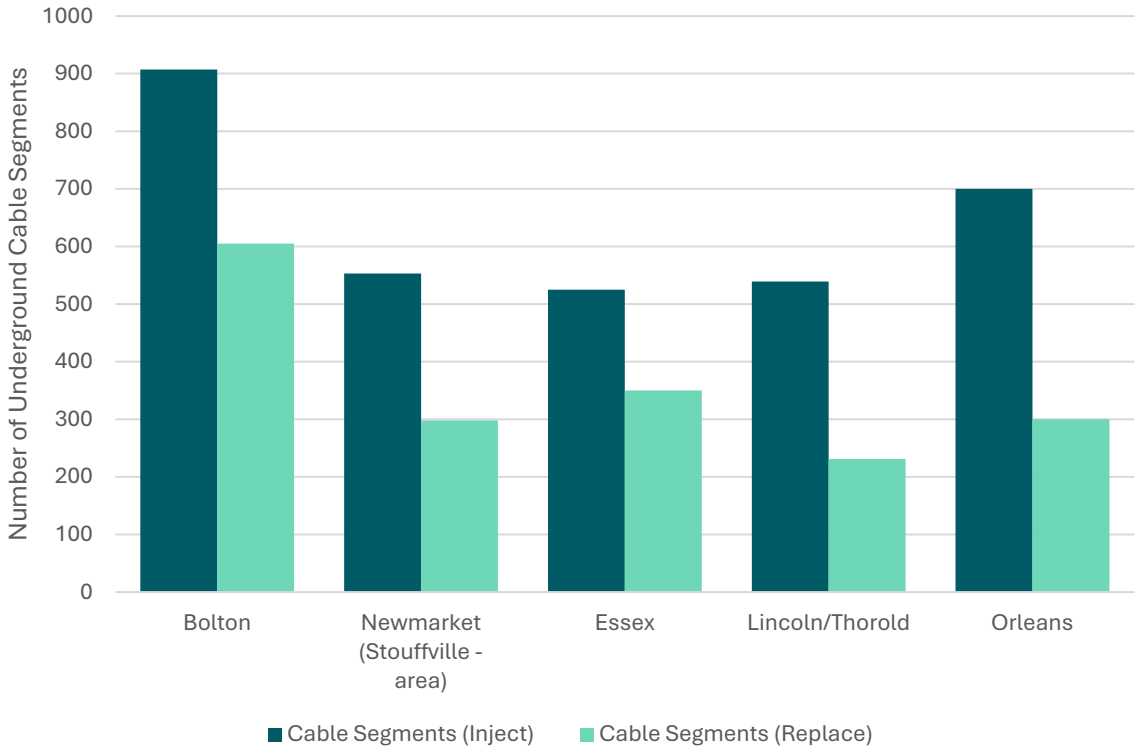


Figure 17: Proposed Underground Cable Segment Volumes for Replacement/Rejuvenation in the Focus Areas

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred approach.

ALTERNATIVE 1: REACTIVE UNDERGROUND CABLE REPLACEMENT AND REJUVENATION

This alternative would involve maintaining underground cables on a run-to-failure basis and addressing failed underground cables through the DSP Section 3.11, D-SR-05 investment (trouble program).

As discussed in the *Investment Need* section, a reactive approach results in lengthy outages and significant disruption to customers. Under DSP Section 3.11, D-SR-05, only the failed section of a cable segment is replaced or spliced, leaving the residual deterioration along the rest of the segment unaddressed and exposing customers to further faults. Because failures occur without warning, reactive work is also more difficult to execute, particularly where the cable segment has no back-feed capability.

This alternative was rejected because it would continue to rely on reactive response after failure, would not address residual deterioration along the remaining cable segment, and would expose customers to recurring outages and repeated restorations. A planned program allows Hydro One to identify deteriorating cable segments (through diagnostic testing) before they fail. This allows customers to be given notice in advance of the replacement or rejuvenation work to minimize disruption, and to schedule crews efficiently.

ALTERNATIVE 2: ACCELERATED REPLACEMENT OF UNDERGROUND CABLES

This alternative would involve addressing an estimated 1,000km of underground cables identified as being in poor condition within a single five-year rate period. Unlike the recommended approach, which focuses on 750km of priority cable infrastructure in the five Focus Areas, this alternative would expand the scope to include additional areas and a larger population of deteriorated cable segments. While this accelerated and comprehensive approach could improve asset condition more rapidly, it presents significant challenges from an execution and resourcing perspective.

Considering that underground cable maintenance has historically followed a run-to-failure strategy, Hydro One would need to further develop internal processes, work methods, and specialized skill sets to efficiently deliver a program of this magnitude. Implementing such an aggressive approach without sufficient organizational readiness could introduce execution risks, inefficiencies, and potential cost escalations.

As a result, this alternative was not pursued. Instead, Hydro One has elected to focus on addressing poor condition cables within the priority areas (Alternative 3). This targeted approach allows the organization to incrementally develop and refine execution processes, optimize work methods and build the necessary internal capabilities.

ALTERNATIVE 3: PLANNED REPLACEMENT OR REJUVENATION OF UNDERGROUND CABLES (RECOMMENDED)

The recommended alternative replaces or rejuvenates underground cables in areas mentioned in this document that are experiencing poor underground cable reliability. Diagnostic testing will be performed on cables that are beyond ESL or approaching ESL during the 2028-2032 planning period in these areas to determine cable condition and the appropriate remediation strategy.

In this alternative, approximately 750km of underground cables that are at ESL or approaching ESL are planned to be remediated through cable rejuvenation or replacement in the problematic areas. A planned underground cable replacement and rejuvenation program is more prudent and operationally efficient than a reactive, run-to-failure approach. With the continued expansion of Hydro One’s underground cable network and the observed increase in cable-related interruptions, a proactive program will enable Hydro One to address underground cable deterioration before failures occur, thereby reducing the frequency and duration of customer interruptions.

In addition, by targeting underground cables based on condition assessments and reliability performance metrics, a planned approach supports improved system reliability and enhances the overall customer experience. It also allows work to be scheduled in a coordinated and efficient manner, optimizing resource utilization and minimizing disruption.

6.0 EXECUTION RISK AND MITIGATION

Historically, Hydro One has maintained underground cables using a run-to-failure approach. Cables were only replaced or repaired during failures under the Distribution Lines Trouble Call and Storm Damage Response (DSP Section 3.11, D-SR-05) on a reactionary basis. This proposed underground cable replacement and rejuvenation program represents a transition from a primarily reactive approach to a planned, condition-based investment strategy. While Hydro One has some existing experience with underground cable rejuvenation and repair work, the program introduces additional execution considerations, including the need to gather comprehensive cable condition information, confirm the appropriate remediation strategy, coordinate work in residential and urban environments, and scale resources to deliver a significantly larger volume of underground cable work than has historically been undertaken. Several key considerations have been made to mitigate the execution challenges as outlined below.

First, rather than pursuing a system-wide replacement program, Hydro One intends to focus investments on areas that present the greatest underground cable reliability impacts. This targeted approach enables Hydro One to concentrate execution efforts in constrained locations, coordinate effectively with municipalities, customers, and communities, and progressively build delivery capabilities in a controlled and manageable manner. Diagnostic testing will play a key role in treatment selection, with results used to determine whether cable rejuvenation or full replacement is the most appropriate option. Where cable condition and design characteristics permit, rejuvenation will be prioritized as the more cost-effective treatment while still addressing reliability concerns.

Second, the execution strategy builds on Hydro One's extensive experience delivering reactive underground cable repairs and replacements. Combining this experience with the work completed under the cable injection program, it provides a strong operational foundation for the transition to a larger, planned program. Although much of the historical work has been reactive in nature, Hydro One has established capabilities in locating, excavating, splicing, and replacing failed underground cable sections, as well as managing the associated civil construction activities such as trenching and site restoration through the Distribution Lines Trouble Call and Storm Damage Response Program (DSP Section 3.11, D-SR-05). In addition, experience gained through the cable injection pilot

program and subsequent rejuvenation work in Orleans provides a practical foundation for developing work methods, designs, outage coordination processes, and execution procedures for a larger planned program.

Third, the proposed expenditure profile is designed to support execution readiness through a phased ramp-up of activities. Increasing spending over the planning period will allow Hydro One to incorporate early diagnostic results, refine work packages, confirm the appropriate rejuvenation and replacement mix, and develop the internal and external execution capacity required to support larger work volumes in later years. This gradual increase also helps mitigate the risks associated with inefficient crew mobilization and the transition from emergency-response practices to a planned delivery model.

To deliver the program efficiently, Hydro One will utilize a combination of internal resources and qualified external vendors. This approach provides flexibility to address specialized work requirements, including excavation, trenching, cable injection, site restoration, and replacement activities in non-standard or constrained locations.

Compared to a reactive strategy, a planned approach provides significant operational and customer benefits. It allows Hydro One to schedule outages in advance, provide timely customer notifications, coordinate municipal and third-party utility requirements, plan restoration activities more effectively, and bundle work where feasible to improve efficiency, support cost control, and minimize customer impacts.

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D-SR-16	CREATION OF VIRTUAL ASSETS
Primary Trigger:	Asset Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	5.9	6.7	7.6	8.6	9.6	38.4
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

The purpose of this investment is to create a digital replication of the Hydro One distribution system and its assets using Light Detection and Ranging (LiDAR) and high-resolution imagery for large-scale data collection. This investment includes the collection of LiDAR data, high resolution orthophotos, and zoomed-in asset imagery, and the engineering of this data to create the distribution system digital twin. The database will consist of a virtual representation of the grid which enables more detailed, precise and updated data collection, innovative inspection approaches and better operational decision making. Costs associated with the use of the digital twin in support of efficient condition-based maintenance and vegetation management are expected to be included in a future rate filing.

This is a new investment without any planned or actual expenditures in the 2023-2027 period. There are no historic or planned capital expenditures for Orillia RZ and Peterborough RZ.

1.0 INVESTMENT NEED

This investment involves the creation of a digital twin of Hydro One's Distribution system. The expenditure includes the capture of data and the process of compiling information into a Hydro One database. The collection of information and curation of the distribution system digital twin is a pre-condition to Hydro One's capability of using the data to make improved operations and maintenance decisions. LiDAR data and high-resolution imagery are the primary data formats used as part of the necessary large-scale data capture of the distribution system.

Future benefits of the digital twin database include:

- The ability to undertake more efficient and improved sustainment planning and condition-based investments in Hydro One's large and geographically dispersed distribution system.
- The opportunity to support improved planning of vegetation management activities by using the captured data as an additional layer of information within Hydro One's Optimal Cycle Protocol (OCP) Flex strategy (see Exhibit E-03-02 for further details).
- Access to greater volumes of current and useful asset information, including images of pole tops and other hard to access assets that provide information about asset condition that was not previously available.
- An asset inventory of the parts of the grid that have been scanned.
- The opportunity to use centimeter-level measurements of poles and equipment, combined with visual evidence of grid configurations, to improve the design and documentation of grid extensions and upgrades. For example, this could support more accurate pole structure modelling, helping Hydro One staff build and analyze pole structures in ways not previously possible (e.g. calculating precise mechanical loads on individual poles, assessing line clearance requirements, calculating thermal line ratings, and generating construction documents). This is especially helpful for all installations that require a high accuracy threshold like overhead line crossings and taps, rail crossings, and congested overhead lines near stations.

- The opportunity to execute safer, more efficient virtual patrols of the distribution system by avoiding certain field-based inspections and patrols, including roadside inspections.
- The opportunity to execute peer validations and quality control of inspection findings more safely, efficiently, and at reduced cost.
- The opportunity to improve training materials by using a greater volume of detailed and up-to-date images and navigable data to further support employee skills development.
- The ability to provide photographic evidence and detailed images in response to customer inquiries, and regulatory and other compliance activities.
- The ability to apply artificial intelligence and various search/analysis algorithms to the database to obtain new insights. For example, combining computer vision with large language models will enable automatic extraction of information about poles matching a specific description. The automatic detection of components and their condition will facilitate more accurate identification of needs, support preventive maintenance operations and extend the useful lives of assets.
- The availability of data to support multiple Distribution lines of business, including Lines, Stations and Forestry Services.

The use of digital twins is becoming common practice in the distribution industry because of the benefits and lowered barrier to entry driven by reduced technology costs. Industry organizations such as EPRI and CEATI support the use of digital twins for improved operations and management of distribution systems. The transmission sector also leverages the use of virtual patrol environments.

Costs associated with the application of the digital twin for the performance of maintenance are not included in this investment and will be included in other Distribution program expenditures.

2.0 INVESTMENT DESCRIPTION

Collecting information regarding the condition of distribution assets and the rights of way in which those assets are located is core to making effective operations, planning and

maintenance decisions. Traditionally, visual inspections and foot patrols have served as primary means of collecting distribution system data. Technological advancements in the areas of digital imaging, LiDAR data collection, data processing and computer-based data analysis have enabled the development of virtual patrol and analysis tools. This, in turn, improves the accessibility and quality of distribution system data and opens new avenues for grid analysis and management.

This investment will fund the data collection and database creation for Hydro One's entire overhead distribution system over five years (approximately 114,000 circuit km of distribution lines province-wide, located within approximately 104,000 km of ROW) using LiDAR data and Nadir images. This corresponds to approximately 20,800 ROW km per year. In addition, this investment will fund drone-based image capture for prioritized poles based on factors such as construction needs and attached equipment.

LiDAR works by shining a laser at objects and timing how long the light takes to bounce back. The technology's ability to execute millions of these actions every second enables exact measurements between objects and creates precise three-dimensional mapping of the distribution system and its surroundings. Figure 1 provides an example of LiDAR data, specifically a distribution power line section located under transmission structures. The two pictures (same scene, different angles) show the distribution lines (grey), a car on the road (orange), a house (red), low vegetation (light green) and high vegetation (dark green).

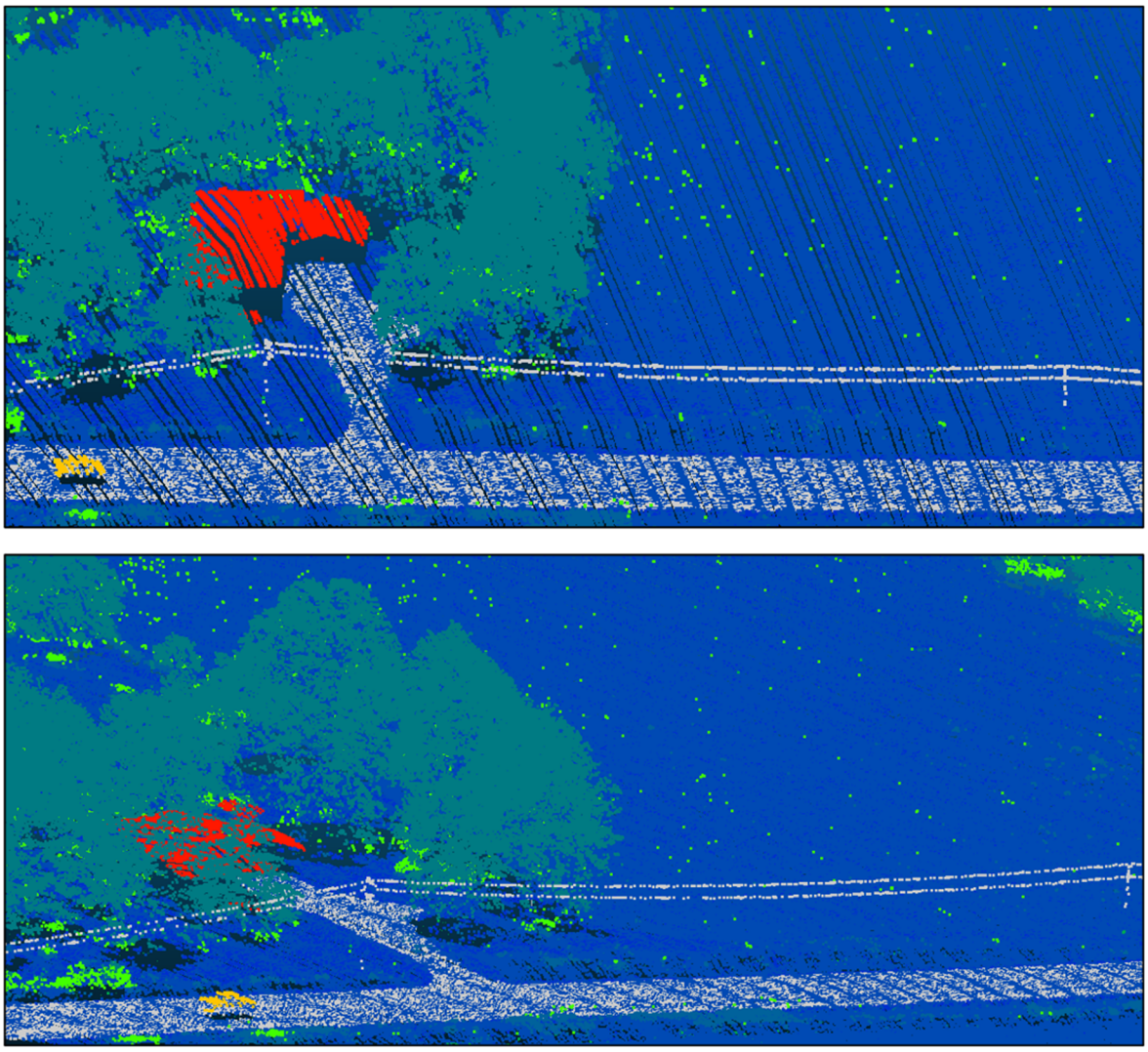


Figure 1: Example of Distribution System LiDAR Data.

Aerial imagery provides unique angles and scaling possibilities for documentation of the grid. Two types of high-resolution imagery will be captured under this investment: (i) Nadir images captured at the same time as the LiDAR point clouds (usually using a fixed-wing aircraft), helping to generate high-resolution orthophotos (see Figure 2) and; (ii) high-resolution images captured by flying a drone equipped with a high-megapixel camera over planned routes. The high resolution of the photos offers users the ability to 'zoom and pan' to view detailed aspects of selected assets and their surroundings (see Figure 3).



Figure 2: Example of a 7.5 cm-resolution orthophoto of Coboconk DS



Figure 3: Example of high-resolution asset and right of way imagery captured with drones.

Hydro One forecasts a gradual increase in the pace of data collection over the 2028-2032 planning period, as the process matures and lessons learned in the field are taken into consideration.

Data collection will be planned and prioritized based on risk levels and on the company's grid modernization plan. Data will be captured aerially using remote sensing methods to obtain engineering-grade LiDAR data and high-resolution imagery for orthophoto preparation of Distribution lines assets and surroundings, helping to characterize levels of encroachment, structure dimensions and grid configuration. Flights to capture LiDAR data and imagery will be validated and supervised by Hydro One Helicopter Services and will be executed by both internal and external groups. Drones will be used to capture high-resolution aerial imagery of poles, which will be combined with ground-based images captured within routine inspection programs. Finally, where operationally executable, Hydro One will also leverage mobile mapping solutions.

Images of poles will be captured with a ground sample distance (GSD) of 0.3 to 1.0 cm/pixel, which can commonly be obtained with 30-megapixel cameras and higher. This level of detail (which otherwise could only have been captured via note-taking during helicopter and ground patrols) allows effective inspection and characterization of assets via desktop review. Multiple high-resolution images per structure will be collected to provide an overall view of structures as well as a view of the spans to which the poles are related. The images will allow strong zoom-in functionality to show structure subcomponents and ancillary components (e.g. pole tops, cross arms, insulators, conductors, bolts and hardware).

The investment will also include the work of design engineers to complete Power Line Systems – Computer Aided Design and Draft (PLS-CADD) modelling of the data into the digital twin environment. Those models help design staff to build and analyze distribution pole structures by calculating precise mechanical loads on individual poles, assessing line clearance requirements, calculating thermal line ratings where relevant, and generating construction documents.

The data captured will remain useful until the applicable assets are replaced or the grid configuration is modified. The data will be processed and uploaded to centralized web-based platforms for visualization and analytics. In addition, Hydro One, as owner of the data, will be able to upload data to company-owned servers accessible across lines of business, thereby creating a 'data lake' and increasing the value of the data. The combination of technologies and the centralization of the data into a data lake will enable Hydro One employees to use the various data sets together. For example, employees could combine a three-dimensional point-cloud representation with centimeter-level measurement precision obtained through LiDAR, a zoomed-in aerial image of a transformer, and a ground-based image of the pole supporting that transformer captured during regular patrols. This combined information will enable precise characterization of assets and equipment, facilitate precise analytics, and support robust decision making. Hydro One will use external vendors to resource the investment.

3.0 OUTCOMES

This investment aims to mitigate system reliability, safety, and environmental risks by allowing Hydro One to access a virtual environment that enables improved management of its overhead system assets through better sustainment planning and condition-based maintenance.

3.1 OEB RRF OUTCOMES

The following table presents anticipated benefits from the investment in accordance with the Ontario Energy Board's Renewed Regulatory Framework:

Table 1 - Outcome Summary

Customer Focus	• Reduce the probability of outages by enabling more effective condition-based maintenance of critical assets. • Reduce outage duration by facilitating the identification of material needs before crews are dispatched for outage response. • Reduce the time required to process customer requests by enabling pole configurations to be assessed remotely.
Operational Effectiveness	• Use of technology to complete requisite distribution system operations and maintenance activities more efficiently and effectively. • Enable safer asset assessments through desktop-based solutions that reduce the need for employees to travel to field locations and their resulting exposure to field related risks.
Public Policy Responsiveness	• Contribute to Hydro One meeting its regulatory compliance obligations related to operations and maintenance, as defined in the Distribution System Code (DSC), Reg 22/04 and in the regulation provided by the Electrical Safety Authority (ESA). • Facilitate the collection of evidence to support communications regarding the status of the grid to parties outside of Hydro One, including customers, telecommunications companies, other local distribution companies, regulators, and media.

4.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 planning period. There are no planned capital expenditures for Orillia RZ or Peterborough RZ.

Table 2 - Hydro One - Investment Expenditures

($M)	Plan[1] 23-27	Act/Fcst[2] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Investment Expenditures	0.0	0.0	5.9	6.7	7.6	8.6	9.6	38.4
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**0.0**	**0.0**	**5.9**	**6.7**	**7.6**	**8.6**	**9.6**	**38.4**

2023-2027 EXPENDITURES

This is a new investment without any planned or actual expenditures in the 2023-2027 period.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are $38.4M. The factors influencing the cost of the investment include:

- the growing availability of technology necessary to establish the digital twin;
- the technology used to collect distribution system and asset data;
- the level of expertise required to capture and process high-quality data (e.g., calibrated data, adequate metadata, proper overlapping of datasets, etc.);
- the volume of data collected and speed of collection;
- regulations governing Beyond Visual Line Of Sight (BVLOS) flights;
- software license costs; and
- hosting of data and application of artificial intelligence and algorithms.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[2] "Act/Fcst" refers to Actual (2023-25) and Forecast (2026-27) expenditures.

ALTERNATIVE 1: STATUS QUO (REJECTED)

The status quo alternative is rejected because this project was developed to seek technologically innovative alternatives to improve Hydro One's current business practice of conducting multiple field-based patrols to satisfy individual line of business inspection needs.

ALTERNATIVE 2: USE OF EXISTING HYDRO ONE TRANSMISSION LIDAR SYSTEMS (REJECTED)

Hydro One has experience with LiDAR systems in the oversight of its transmission system. Hydro One's transmission system has been fully scanned with the purpose of creating up-to-date PLS-CADD models of transmission infrastructure. However, the data collection was executed on transmission ROWs (approximately 21,000 kms), not on distribution ROWs (approximately 104,000 kms) and there is minimal overlap. Therefore, the vast majority of Hydro One's Transmission LiDAR cannot be used for the creation of the Distribution digital twin. In addition, this option did not satisfy the other technical requirements related to the collection of multiple types of data (e.g., high-resolution imagery of targeted poles). Finally, existing systems cannot accommodate storage and viewing of the scale necessary to satisfy the digital twin requirements for the distribution grid.

ALTERNATIVE 3: DEVELOP DIGITAL TWIN BY COLLECTION AND ENGINEERING OF DATA COLLECTED THROUGH LIDAR AND IMAGERY (RECOMMENDED)

The recommended alternative is the most practical approach to developing a digital database that represents the distribution system for the purpose of future operations and maintenance efficiencies. The technologies required to execute the investment, including data capture and database engineering, are now accepted within the industry and are considered to have low technological risk and optimized commercial costs.

6.0 EXECUTION AND RISK MITIGATION

Hydro One has not identified any material execution risks. One low-level risk faced is the availability and capacity of Hydro One Helicopter Services to support data collection. Helicopter Services is aware of the volume of work planned for the period and will allocate resources to have the work completed on time. Vendors will also be available to mitigate

this risk. In terms of the future use of the database, completing vegetation and distribution lines patrols through web-based portals instead of physically viewing assets represents a process change for Hydro One staff. Sufficient training and documentation will be required to ensure that staff have proper training to complete asset patrols virtually.

D-SR-17	VOLTAGE CONSOLIDATION
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	7.5	37.8	35.0	23.3	50.1	153.6
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

The proposed investment leverages planned end-of-life station transformer replacements to convert 23 distribution stations to higher voltage standards, creating a more standardized and efficient distribution network for the customers and communities served by legacy 4.16kV assets. Voltage consolidation improves operational flexibility, strengthens resilience, and mitigates reliability risks associated with non-standard infrastructure. It also increases the available capacity of the local distribution system to support future growth, including electrification and adoption of Electric Vehicles and heat-pumps as well as DERs.

There are no planned investments for Orillia Rate Zone (RZ) or Peterborough RZ.

1.0 INVESTMENT NEED

Hydro One's system contains more than 1,000 distribution and regulation stations and more than 3,300 feeders operating at one of seven voltage levels: 4.16kV, 8.32kV, 12.5kV, 13.8kV, 25kV, 27.6kV, and 44kV.

Maintaining voltage consistency within a community is an important aspect of system planning and operations. Aligning feeder voltages improves the ability to transfer load between feeders, utilize available station capacity, and respond to outages, while simplifying system configuration and reducing operational complexity. Distribution system planning begins at the supply station, where available capacity and operating voltage are established, making station renewal a natural opportunity to address voltage standardization. These benefits become increasingly important as Hydro One renews aging infrastructure and prepares the distribution system to accommodate evolving customer needs and long-term growth.

When distribution station transformers reach end-of-life, Hydro One has an opportunity to renew major station components while enhancing the broader distribution system. Where existing station voltages are obsolete or misaligned with adjacent portions of the network, station renewal provides a cost-effective opportunity to standardize voltage levels and improve system integration. Coordinating voltage consolidation with planned end-of-life asset replacement allows Hydro One to modernize aging infrastructure, simplify operations, and improve flexibility. Bundling station and downstream line conversion also avoids future rework and reduces customer and community disruptions.

For a Distribution Station, implementing a voltage conversion requires replacement of key station components, including:

- Station transformers;
- Low-voltage bus structure equipment, including insulators, switches, lightning arresters, metering equipment, and station service transformers;
- Low-voltage reclosers; and
- Low-voltage cabling for stations with underground feeder egress.

4.16KV SYSTEM

Hydro One maintains a 4.16kV distribution system, largely acquired through legacy local distribution company (LDC) acquisitions, located in smaller townships supplying more than 40,000 customers in total. The system comprises 481 distribution feeders supplied from 142 distribution stations, spanning more than 1,900 circuit kilometres and supported by more than 44,000 wood poles. While this infrastructure has provided decades of service, much of the remaining 4.16kV network was constructed to historical standards and approximately 22% of these poles will reach or exceed Expected Service Life (ESL) by 2032. Furthermore, approximately 2,600 4.16kV poles are in poor condition, which represents approximately 6% of the total number of 4.16kV poles. These aging and poor-condition assets are increasingly susceptible to deterioration, equipment failures, and weather-related damage, increasing the risk of customer interruptions and reliability degradation for the customers supplied from those feeders. Rebuilding these assets through Voltage Consolidation addresses the risks associated with aging and poor condition assets. Figure 1 illustrates an example of three 4.16kV feeders as they egress from a distribution station.



Figure 1: Photograph of a 4.16kV Pole Line Outside Forrest Jefferson DS

In addition, the legacy design of the 4.16kV system limits operational flexibility and system performance. Many 4.16kV feeders cannot be transferred to adjacent stations because of voltage incompatibility with neighboring feeders, limiting Hydro One's ability to restore customers following outages or respond efficiently to changing operating conditions. Furthermore, this system voltage may make it more difficult to transfer load and reconfigure the network during outages, due to limited capacity on 4.16kV feeders.

The more than 1,900 circuit kilometres of existing 4.16kV distribution line offer limited capacity relative to modern distribution standards, with a typical 4.16kV feeder having a capacity limit of approximately 2 MVA - a demand level that can be consumed by only a small number of customers. Unlike higher-voltage systems, 4.16kV feeders can become constrained with relatively modest increases in demand. Voltage Consolidation

significantly increases load-serving capability within the existing infrastructure footprint. For example, an 8kV feeder can accommodate approximately twice the load of a 4kV feeder, with capability increasing further at higher voltage classes such as 12.5kV, 25kV, and 27.6kV. The additional capacity supports future load growth, including increasing electrification, and the integration of distributed energy resources (DERs).

The 4.16kV system also presents some obsolescence risks by relying on equipment and station configurations that are increasingly difficult to maintain, source, and support. Figure 2 below shows an example of a 4.16kV metal-clad switchgear, which is the primary protective device for feeders emanated from the Carleton Place Napoleon DS. It is increasingly difficult to procure replacement parts for metal-clad switchgear, creating reliability risks associated with the inability to restore customers during equipment-related outages.



Figure 2: Photograph of a 4.16kV Metal-Clad Switch Gear at Carleton Place Napoleon DS

Voltage Consolidation addresses the reliability, lack of operational flexibility, capacity limitations, and obsolescence risks, of the 4.16kV system by modernizing the network to align with current distribution standards. A more standardized distribution system also simplifies near-term design, construction, and operations of the distribution system. Long-term benefits of Voltage Consolidation include simplified maintenance, procurement flexibility, streamlined inventory management, mitigation of obsolescence risks, and contracting efficiency through the use of common equipment and materials.

2.0 INVESTMENT DESCRIPTION

Voltage consolidation involves converting a distribution station and the feeders it supplies from 4.16kV to a higher standard system voltage, typically 8.32kV or above. The work is undertaken as a single area project: the station transformer is replaced or reconfigured to operate at the higher voltage, and the downstream distribution lines, poles, conductors, transformers, and switches in that area are replaced or converted at the same time so that the entire area transitions together.

Over the 2028-2032 rate period, Hydro One will upgrade twenty-three 4.16kV end-of-life distribution station transformers to operate at a higher voltage and replace approximately 200 circuit kilometres of 4.16kV distribution line to operate at a higher standard system voltage that is compatible with adjacent feeder voltages to establish new feeder ties. This pacing represents a gradual approach to consolidating standard system voltages, reducing the more than 1,900 circuit-kilometer 4.16kV assets over a timeframe that coincides with the associated 4.16kV distribution station transformers reaching end-of-life.

Voltage consolidation is Hydro One's preferred renewal approach in 4.16kV areas where major station assets, particularly station transformers, are in poor condition and planned for replacement. Accordingly, Hydro One coordinates voltage conversion of 4.16kV systems with Distribution Station Renewal (DSP Section 3.11, D-SR-04), allowing both the station and downstream distribution network to transition to the higher operating voltage concurrently. Pacing of 4.16kV transformer replacement is outlined in DSP Section 3.11, D-SR-04 Section 2.0 and involves replacing poor-condition transformers where corrective maintenance cannot provide a sufficient extension of the transformer’s life. Rather than replacing assets piecemeal, area conversion bundles the renewal of poles,

conductors, transformers, switches, and other distribution assets into a single coordinated program. This approach combines the long-term benefits of voltage standardization with the renewal of end-of-life infrastructure.

3.0 OUTCOMES

Transitioning to standard voltages provides the following customer outcomes:

- Improve feeder load-carrying and DER hosting capability and enables additional, stronger feeder ties that support operational flexibility and emergency restoration activities thereby improving reliability
- Higher voltage operation lowers electrical losses and improves system efficiency
- Reduce and eventually eliminate operational activities associated with 4.16kV assets, such as procurement and inventory management
- Improve execution efficiencies through work bundling and enable better planned outage scheduling to minimize customer interruptions

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the investment in accordance with the Ontario Energy Board's ("OEB") Renewed Regulatory Framework ("RRF"):

Table 1 - RRF Outcome Summary

Customer Focus	• Avoid customer interruptions by proactively addressing poor-condition linear assets, such as poles and conductors, prior to failure. • Support future capacity needs, such as electrification and DER enablement, by providing higher voltage lines with inherently more capacity.
Operational Effectiveness	• Maintain reliable operation of the distribution system by replacing poor-condition linear assets, such as poles and conductors, in an integrated manner, bundled with major end-of-life station asset replacement investments. • Increase operational flexibility by aligning feeder voltages in 4.16kV towns to match other existing higher voltages on the outskirts of town, which provides additional feeder tie capability • Reduce feeder losses by increasing feeder voltage, and thus reducing feeder thermal (I^2R) losses.
Public Policy Responsiveness	• Enhancing system resiliency for targeted assets in locations prone to extreme weather by increasing feeder voltage to unlock additional tie capability by aligning with adjacent feeder voltages.

4.0 EXPENDITURE PLAN

2023-2027 EXPENDITURES

This is a new program and there were no expenditures during the 2023-2027 period.

2028-2032 EXPENDITURES

Table 2 below summarizes Hydro One's 2028-2032 forecast capital expenditures. These projects are outlined in greater detail in Appendix A of this document.

There are no planned expenditures for Orillia RZ or Peterborough RZ.

Table 2 - Hydro One – Investment Expenditures

($M)	Plan[1] 23-27	Act/Fcst[2] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	-	8.5	42.9	39.7	26.5	57.0	174.6
Less Removals	-	-	1.0	5.2	4.8	3.2	6.8	21.0
Less Capital Contributions	-	-	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	-	-	**7.5**	**37.8**	**35.0**	**23.3**	**50.1**	**153.6**

The forecast for voltage consolidation investments is based on recent-historical estimated project costs, and the volume of work identified over the forecast period. For each identified Voltage Consolidation investment, the length of the distribution lines to be rebuilt have been determined, and historical per kilometer unit prices were applied to estimate the cost per project, with design and construction timing aligned with DSP Section 3.11, D-SR-04 (Distribution Station Renewal) investments.

Furthermore, there are no immaterial investments, nor investments in the Orillia and Peterborough RZs, during the 2028-2032 rate period.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[2] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred Voltage Consolidation approach.

ALTERNATIVE 1: MAINTAIN 4.16KV INFRASTRUCTURE

This alternative involves completing no voltage consolidation work. Specifically, Hydro One would maintain the existing system voltages for all planned 4.16kV Distribution Station Renewal investments proposed in DSP Section 3.11, D-SR-04.

This alternative would result in continued reliability limitations for customers served by 4.16kV feeders. Since these feeders operate at a different voltage than surrounding distribution feeders, Hydro One's ability to transfer customers to adjacent feeders during outages or planned work is constrained. This reduces operational flexibility, increases restoration challenges during unplanned outages, and can result in longer outage durations for customers.

Maintaining the existing 4.16kV systems would also perpetuate the limitations associated with lower-voltage distribution infrastructure, including higher electrical losses, poorer voltage performance, and reduced feeder capacity. These constraints limit Hydro One's ability to accommodate future load growth, support electrification, integrate distributed energy resources (DERs), and utilize available capacity from adjacent stations.

In addition, maintaining legacy 4.16kV infrastructure would require Hydro One to continue supporting a separate class of assets, including specialized procurement, inventory management, engineering standards, work procedures, and technical expertise. Voltage consolidation provides an opportunity to improve operational efficiency by reducing and, over time, eliminating these legacy requirements.

Accordingly, this alternative was considered and rejected.

ALTERNATIVE 2: PACE 4.16KV VOLTAGE CONSOLIDATION IN COORDINATION WITH DISTRIBUTION STATION RENEWAL ACTIVITIES (RECOMMENDED)

This alternative involves upgrading 23 end-of-life distribution station transformers to operate at a higher voltage and replacing approximately 200 circuit kilometres of 4.16kV distribution line to operate at a higher standard system voltage that is compatible with voltages already present in the subject communities. This approach provides the operational, reliability, load capacity, supply chain, and inventory management benefits described above.

Furthermore, by coordinating voltage consolidation work with planned end-of-life Distribution Station Renewal investments (DSP Section 3.11, D-SR-04), Hydro One can efficiently modernize both the station and distribution infrastructure through a single, integrated investment strategy. This approach avoids the need to replace distribution station assets configured to serve 4.16kV systems that would otherwise require conversion in a future planning period, thereby reducing the risk of duplicative investment and stranded assets while improving overall capital efficiency.

ALTERNATIVE 3: REPLACE 4.16KV INFRASTRUCTURE IN ADVANCE OF STATION TRANSFORMERS REACHING END OF LIFE

This alternative involves upgrading thirty distribution station transformers during the 2028-2032 planning period to operate at a higher voltage and replacing more than 270 circuit kilometres of 4.16kV distribution line to operate at a higher voltage. These thirty transformers include the twenty three transformers described in Alternative 2, and seven additional 4.16kV transformers that may otherwise be addressed through corrective maintenance.

Compared with other alternatives, this approach would provide the greatest reduction in overall asset failure risk and potential customer outage mitigation. However, the incremental benefits achieved are expected to diminish relative to the additional investment level required. As a result, this alternative is not recommended.

6.0 EXECUTION RISKS AND MITIGATION

The following risks could affect the cost and timely execution of the proposed voltage consolidation projects:

- **Real Estate Acquisition Challenges:** Real estate acquisition challenges for the proposed station site if expansion is required, including land availability, market valuation, and seller expectations. This risk is managed by clearly defining station requirements early and engaging the Real Estate team at the onset to negotiate acquisition timeline and pricing to align with project in-service date.
- **Environmental Impacts:** Potential environmental remediation requirements at site or impacts related to construction near lands of cultural significance. This risk is mitigated through early involvement with the Environmental Services team during the initial design phase will identify environmental constraints and sensitive cultural lands of significance.
- **Cost Escalation:** Unexpected cost escalations, including broader industry-wide cost pressures, as detailed in SPF Section 1.8. This risk is mitigated through multiple controls:
    - Supply Chain collaboration with vendors to establish bulk and long-term pricing contracts for competitive and predictable costs
    - Project Development to consistently work with internal and external stakeholders to bundle similar design and construction projects to capture economies of scale
- **Mobile Unit Substation (MUS) Availability:** Limited availability of MUS for planned station renewal due to increased transformer failures or competing deployment of MUS for other initiatives, such as load growth investments specified in DSP Section 3.11, D-SS-01, and corrective station maintenance activities specified in Exhibit E-03-02, Section 2.1.2. This risk is mitigated through timely release of projects to execution phase to enable Hydro One to properly plan and schedule MUS and related resources to reduce risk of delays and cascading impacts to future planned projects
- **Supply Chain Disruptions:** Extended lead times for critical components, such as power transformers and electronic equipment, could jeopardize project in-service dates if materials are delayed. This risk is mitigated through ongoing communication

between supply chain and vendors regarding material lead times, combined with the ability to pre-order known long-lead items to improve material availability when required.

- **Seasonal Access Limitations:** Seasonal construction constraints may affect project execution schedules. This risk is mitigated through detailed post-engineering work planning that aligns resource allocation with optimal construction start and end dates.
- **Equipment Outage Availability**: Limited availability of equipment outages could delay construction activities. This risk is mitigated by scheduling required outages during work plan development to minimize the potential for outage cancellations after construction has commenced.
- **Property Access Risks:** Delays in obtaining temporary or permanent access to private property could affect project execution. This risk is mitigated by negotiating property access agreements during the detailed engineering stage of the project, minimizing the risk of inability to access.

APPENDIX A - HYDRO ONE DESCRIPTION OF INVESTMENTS

Table 3 - Hydro One - Detailed Material Investment Costs ($M)[3]

Project Name	Project ID	Project Description	Net Capital Investment ($M)				
			2028	2029	2030	2031	2032
Deseronto DS	D-SR-17.01	Convert existing 44/4.16kV station to 44/8.32kV DS via DS and 36km of feeder upgrades	3.3	18.1	0.0	0.0	0.0
Elk Lake DS	D-SR-17.02	Convert existing 44/4.16kV station to 44/12.5kV PDS via PDS and 23km of feeder upgrades	2.6	11.6	0.0	0.0	0.0
Shelburne DS	D-SR-17.03	Convert existing 44/4.16kV station to 44/8.32kV DS via DS and 5km of feeder upgrades	1.6	2.9	0.0	0.0	0.0
Alex Kenyon West DS	D-SR-17.04	Convert existing 44/4.16kV station to 44/8.32kV DS via DS and 1km of feeder upgrades	0.0	0.6	2.1	0.0	0.0
Arnprior Madawaska DS	D-SR-17.05	Convert existing 44/4.16kV station to 44/12.5kV DS via DS and 5km of feeder upgrades	0.0	0.6	4.0	0.0	0.0
Brockville Park T1 DS	D-SR-17.06	Convert existing 44/4.16kV station to 44/8.32kV DS via DS and 4km of feeder upgrades	0.0	0.7	3.2	0.0	0.0
Chesterville Bran DS	D-SR-17.07	Convert existing 44/4.16kV station to 44/8.32kV DS via DS and 8km of feeder upgrades	0.0	0.8	5.7	0.0	0.0
Forest McNab DS	D-SR-17.08	Convert existing 27.6/4.16kV station to 27.6/8.32kV PDS via PDS and 10km of feeder upgrades	0.0	1.1	7.5	0.0	0.0
Smiths Falls James DS	D-SR-17.09	Convert existing 44/4.16kV station to 44/13.8kV DS via DS and 6km of feeder upgrades	0.0	0.9	6.3	0.0	0.0
Trenton McAuley DS	D-SR-17.10	Convert existing 44/4.16kV station to 44/8.32kV DS via DS and 2km of feeder upgrades	0.0	0.6	2.8	0.0	0.0
Owen Sound 12 St E T1 DS	D-SR-17.11	Convert existing 44/4.16kV station to 44/13.8kV DS via DS and 5km of feeder upgrades	0.0	0.0	1.1	4.0	0.0
Shelburn Andrew DS	D-SR-17.12	Convert existing 44/4.16kV station to 44/8.32kV PDS via PDS and 6km of feeder upgrades	0.0	0.0	1.0	4.0	0.0

[3] Figures presented in the tables may not sum to the totals shown due to rounding

Project Name	Project ID	Project Description	Net Capital Investment ($M)				
			2028	2029	2030	2031	2032
Trenton Dixon DS	D-SR-17.13	Convert existing 44/4.16kV station to 44/8.32kV PDS via PDS and 13km of feeder upgrades	0.0	0.0	1.3	6.2	0.0
Brockville Park T2 DS	D-SR-17.14	Convert existing 44/4.16kV station to 44/8.32kV DS via DS and 5km of feeder upgrades	0.0	0.0	0.0	0.8	3.7
Campbellford King DS	D-SR-17.15	Convert existing 44/4.16kV station to 44/12.5kV DS via DS and 8km of feeder upgrades	0.0	0.0	0.0	0.9	4.8
Forest Jefferson DS	D-SR-17.16	Convert existing 27.6/4.16kV station to 27.6/8.32kV PDS via PDS and 12km of feeder upgrades	0.0	0.0	0.0	1.3	8.2
Maxville Prince DS	D-SR-17.17	Convert existing 44/4.16kV station to 44/8.32kV PDS via PDS and 9km of feeder upgrades	0.0	0.0	0.0	1.1	6.3
Owen Sound 12 St E T2 DS	D-SR-17.18	Convert existing 44/4.16kV station to 44/13.8kV DS via DS and 7km of feeder upgrades	0.0	0.0	0.0	0.8	3.8
Peterborough Erskine DS	D-SR-17.19	Convert existing 44/4.16kV station to 44/8.32kV PDS via PDS and 10km of feeder upgrades	0.0	0.0	0.0	0.9	4.6
Thorold Allanport DS	D-SR-17.20	Convert existing 27.6/4.16kV station to 27.6/13.8kV PDS via PDS and 3km of feeder upgrades	0.0	0.0	0.0	0.5	1.0
Thorold Front DS	D-SR-17.21	Convert existing 13.8/4.16kV station to 13.8/8.32kV PDS via PDS and 9km of feeder upgrades	0.0	0.0	0.0	0.8	3.9
Thorold Ormond DS	D-SR-17.22	Convert existing 13.8/4.16kV station to 13.8/8.32kV PDS via PDS and 5km of feeder upgrades	0.0	0.0	0.0	0.6	2.2
Virginiatown DS	D-SR-17.23	Convert existing 44/4.16kV station to 44/8.32kV DS via DS and 22km of feeder upgrades	0.0	0.0	0.0	1.6	11.6
Total			**7.5**	**37.8**	**35.0**	**23.3**	**50.1**

D-SS-01	SYSTEM UPGRADES DRIVEN BY LOAD GROWTH
Primary Trigger:	Capacity
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	250.2	282.9	357.7	259.7	227.0	1,377.4
Orillia Rate Zone (RZ)	0.20	0.13	0.00	Embedded in Hydro One Networks		
Peterborough Rate Zone (RZ)	0.00	0.00	0.00			

Summary:

Load growth investments address system capacity constraints that arise from load growth on the distribution system. These investments are triggered when forecast demand exceeds the existing capacity of system components. Capacity constraints are addressed through targeted system upgrades or modifications, ensuring the distribution system continues to reliably meet forecasted customer demand.

1.0 INVESTMENT NEED

Section 3.3 of the Distribution System Code (DSC) requires distributors to plan and build their systems to accommodate reasonable forecast load growth. In accordance with this obligation, Hydro One must ensure that its distribution system has sufficient capacity to reliably serve both existing customers and new load arising from regional growth. The System Upgrades Driven by Load Growth investments address capacity constraints that emerge when demand exceeds an asset's planning limit, considering factors such as ampacity limitations, protective equipment ratings, and voltage limitations.

The primary driver of this investment is the mitigation of specific system components, including stations, feeders, and downstream equipment, that are overloaded or forecasted to become overloaded within the 2028-2032 planning period. These constraints are identified through Hydro One's load forecasting and system planning assessments, which evaluate forecast load growth against the rated capacity and planning limits of individual assets. Where forecast demand exceeds planning limits, targeted system upgrades are required to maintain reliability, power quality, and compliance with the DSC. A number of Hydro One's assets are, or are projected to be, operating beyond their planning limits over the 2028-2032 period and require investment to increase capacity.

Load growth within Hydro One's service territory is being driven primarily by increased residential development associated with provincial and municipal housing policies, and commercial and institutional growth that typically accompanies new housing. New subdivision developments, intensification within existing communities, and mixed use developments increase both aggregate system demand and localized loading on specific parts of the distribution system. As detailed in DSP Section 3.11, D-SA-02, customers provide capital contributions towards system modifications associated with their specific load connections, in accordance with the DSC. However, load growth in a localized area due to development activity can affect upstream assets such as feeders and stations. In accordance with the DSC, these assets must be reinforced to accommodate this load growth and preserve reliability for existing customers.

System capacity constraints associated with load growth can manifest in several ways, including low voltage conditions, feeder unbalance, thermal overloads, and reduced

operating flexibility. The examples provided in Section 2, under “Feeder Investments” and “Station Investments”, illustrate the various ways system constraints can arise from load growth. These examples also demonstrate how Hydro One plans to address these constraints during the 2028-2032 planning period.

The investments proposed are required to address identified capacity constraints on specific assets that are currently overloaded or that are projected to be overloaded based on forecast demand. These investments are necessary to maintain compliance with the DSC, preserve reliability and power quality, and ensure that Hydro One can continue to support residential development, and electrification within its service territory.

Figure 1 below demonstrates the current regional utilization on Distribution Stations where System Upgrades Driven by Load Growth investments are forecasted during the 2028-2032 planning period. Furthermore, the figure illustrates by how much those assets would be overloaded if Hydro One did not undertake System Upgrades Driven by Load Growth investments. On average, the stations with proposed investments across all four of Hydro One distribution’s operating regions are currently loaded close to 90% of their planning limit. Hydro One is forecasting load demand to exceed 140% of those stations’ planning limit by 2032 averaged across the province. This figure also demonstrates transformer utilization at all other distribution stations, including both present utilization as well as forecasted utilization by 2032. Overall, this figure showcases that Hydro One is targeting stations where available capacity is low and is expected to be exceeded within the 2028-2032 planning period in contrast to the rest of its station transformer fleet.

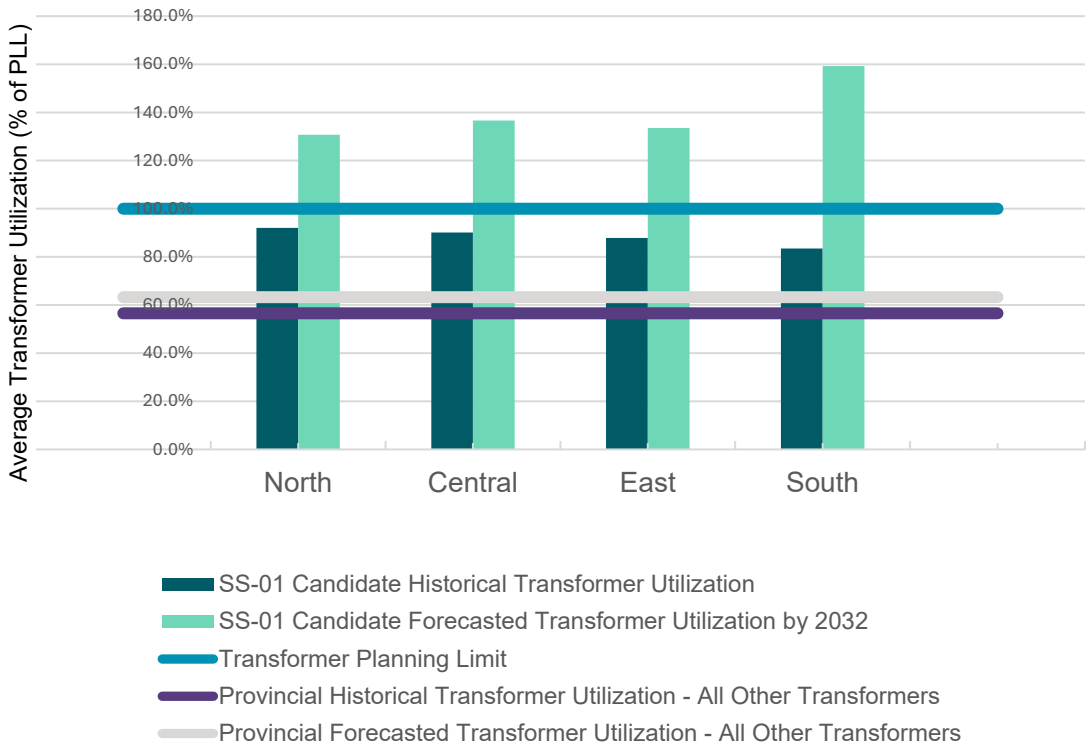


Figure 1: Historical and Forecasted Station Transformer Utilization for System Upgrades Driven by Load Growth Investments vs. all other Station Transformers

Similarly, Figure 2 below provides current average utilization of the feeders that require System Upgrades Driven by Load Growth investments across Hydro One's four regional operating areas. Current feeder utilization for the subject feeders is approximately 94% of Planning Limit. Hydro One expects average feeder utilization on these feeders to exceed 200% if these investments are not undertaken during the 2028-2032 planning period. Furthermore, this figure also demonstrates average feeder utilization for all other distribution feeders, including both present utilization as well as forecasted utilization by 2032. Overall, this figure illustrates that Hydro One is targeting feeders where available capacity is limited and is expected to be exceeded within the 2028-2032 planning period in contrast to the rest of its feeders across the province.

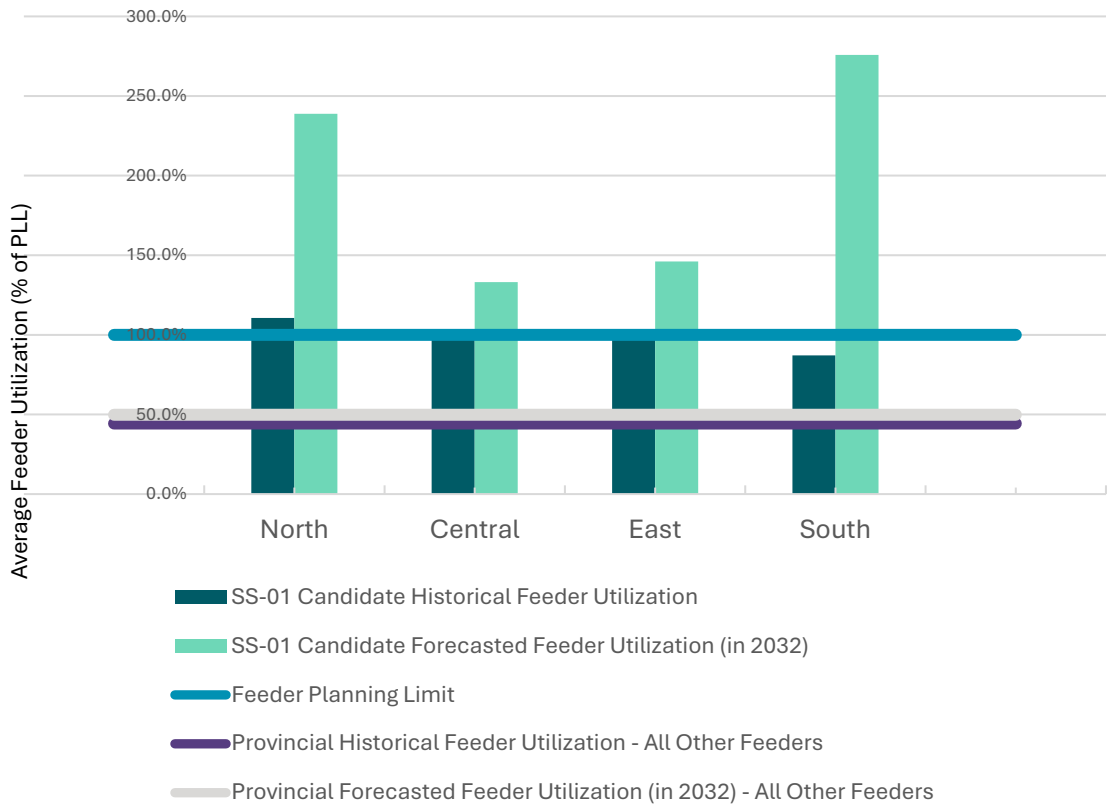


Figure 2: Regional Feeder Utilization for System Upgrades Driven by Load Growth Investments vs. all other feeders

Tables 1 and 2 below provide a view of transformer and feeder utilization by region. Specifically, for the System Upgrades Driven by Load Growth investments associated with station transformers and feeders that are overloaded or forecast to be overloaded during the 2028-2032 planning period, the tables provide:

- a regional breakdown of assets projected to become overloaded;
- the timing of projected asset overloads by region;
- the total number of overloaded assets in each region; and
- the percentage of assets in each region that are projected to become overloaded.

Table 1 - Overloaded Station Transformers Regional and Annual Breakdown

Region	Year of Overload						Total Forecasted Overloaded Assets	% Overloaded Assets by Region
	Prior to 2028	2028	2029	2030	2031	2032		
North	3	0	2	1	0	0	6	2.1%
Central	27	12	2	3	0	8	52	12.2%
East	15	4	4	2	1	3	29	9.0%
South	21	8	10	7	10	5	61	14.9%

Table 2 - Overloaded Feeders Regional and Annual Breakdown

Region	Year of Overload						Total Forecasted Overloaded Assets	% Overloaded Assets by Region
	Prior to 2028	2028	2029	2030	2031	2032		
North	4	1	1	0	0	0	6	1.5%
Central	9	6	1	0	0	0	16	1.7%
East	13	2	8	3	1	1	28	2.8%
South	14	15	6	6	6	6	53	5.7%

1.1 ELECTRIFICATION

Electrification is expected to be a significant contributor to future electricity demand growth in Ontario. IESO's Annual Planning Outlooks and related technical papers consistently identify transportation electrification, building electrification and industrial electrification as important drivers of future demand growth and changing system needs. Ontario government energy planning documents similarly frame future electricity planning around increasing demand from sources such as electrification.

Electrification is expected to contribute to capacity pressures on the distribution system. For example, increasing localized EV adoption can accelerate capacity constraints on secondary assets such as service transformers, when multiple EVs charge within the same area. Hydro One takes a measured and data driven approach to forecasting these local electrification impacts, with the use of the EPRI Hotspotter tool to estimate

overloaded secondary transformers due to EV penetration during the 2028 to 2032 period. Further details below in Section 2.3, subsection Secondary Electrification Program.

1.2 IDENTIFICATION OF REQUIRED INVESTMENTS

Hydro One applies a systematic planning process to identify distribution system investments required to address system needs due to load growth to ensure that the distribution system continues to operate reliably. This process is informed by both historical feeder level and station level loading and forecasted demand.

During localized distribution capacity assessments, load forecasts are developed based on information received from customers, developers, and municipalities, to inform the identification of local system constraints and the need for Load Growth driven System Upgrades to address those constraints. As part of the Regional Planning process, Hydro One develops forecasts to assess future capacity requirements and identify system needs arising from regional and localized growth. As discussed in DSP Section 3.7, Subsection 3.7.3.2 these forecasts incorporate municipal development and growth information obtained through ongoing engagement with municipal planning staff, review of official plans where available, and participation in regional planning activities. The resulting forecasts are used to assess supply capability and reliability at both the regional and localized level, generally focusing on portions of the system supplied at 115 kV or 230 kV.

Load forecasts used for investment planning reflect a combination of historical loading conditions and anticipated changes in customer demand. Forward looking demand expectations are developed using established forecasting methodologies and are informed by economic and demographic assumptions as described in Exhibit D-05-01, subsection 2.0, as well as local input from municipalities, developers, and customers with known or expected changes in load. These forecasts are applied at the asset level to assess the impact of load growth on individual system components and to determine when existing assets are expected to approach or exceed their planning limits.

The capability of distribution assets is assessed in accordance with Hydro One planning limits, equipment ratings, and relevant industry standards and best practices. Engineering analysis is undertaken to evaluate system performance under forecasted loading

conditions and to identify emerging system limitations, which may include capacity, voltage, or protection constraints. Based on this assessment, Hydro One identifies system needs and the associated timing by which investment is required. Potential solutions are then developed and evaluated to address the identified needs. These solutions may include modifications to existing infrastructure, targeted asset upgrades or additions, system reconfiguration, and, where appropriate, Non-Wires Solutions (NWS) as described further in DSP Section 3.6, subsection 3.6.5.

As outlined in DSP Section 3.7, Hydro One applies a risk based approach to pace and prioritize system investments. Potential solutions considered are assessed to ensure their technical viability and their ability to address the forecasted load growth. In determining the timing of investments, Hydro One considers the level of risk associated with deferring investment, informed by the expected timeline for the forecasted load to materialize. Investments required to address more immediate risks are prioritized for earlier execution, while investments associated with emerging needs are staged to align with expected demand growth. This approach ensures the proposed capital investments are prudently timed to support load growth and maintain the continued safe and reliable operation of the distribution system.

Figure 3 below illustrates the regional distribution of material investments (greater than $1 million in net expenditures) planned for the 2028-2032 period. In total, 189 material investments are required to address load growth related distribution system needs, with most investments concentrated in Southern and Central Ontario.

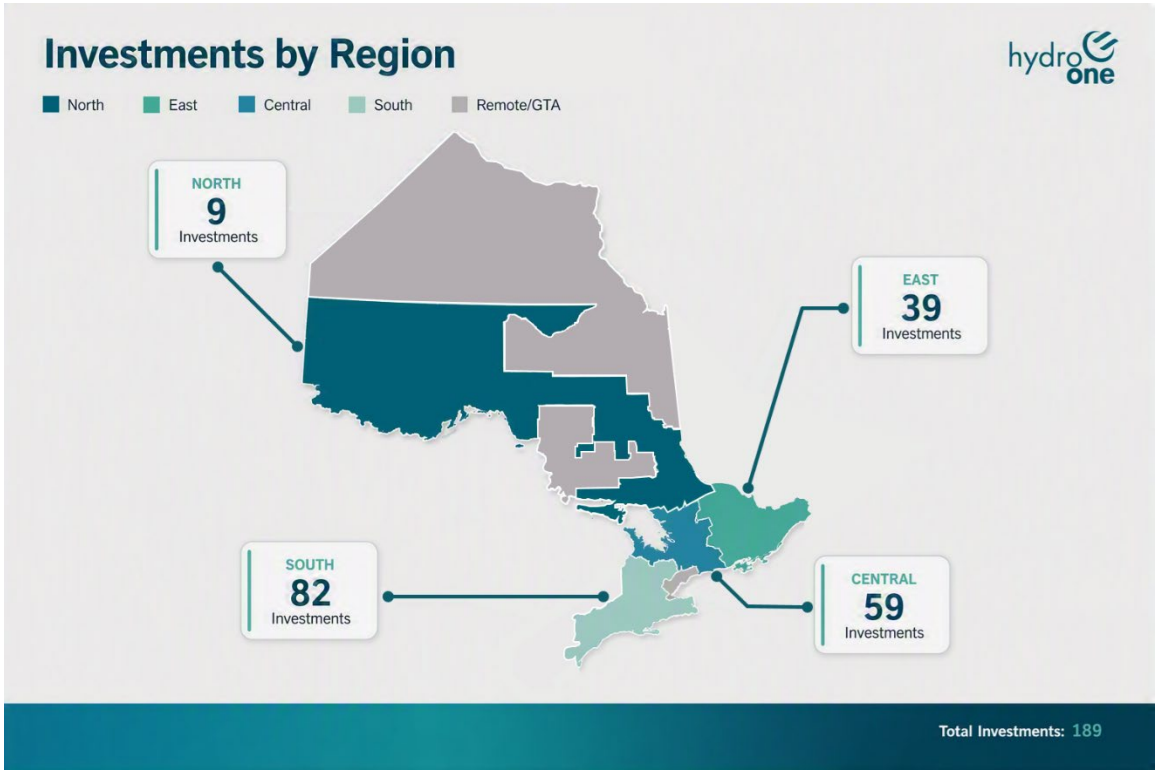


Figure 3: Regional Breakdown of Forecasted Material Load Growth Investments in the 2028-2032 Planning Period

Load growth investments, which are listed in Appendices A, B, and C to this document, address capacity constraints that would otherwise interfere with Hydro One's obligations to accommodate reasonable load growth and connect new customers in a timely manner.

Non-Wires Solutions, listed in Appendix D, are those investments which address system needs by providing customer and third party incentives to reduce peak demand loading. These are cost effective operational solutions which defer the need for traditional capital investments under this ISD, in accordance with OEB's requirements under the NWS Filing Guidelines. For more information about Hydro One's NWS process, please refer to DSP Section 3.6, subsection 3.6.5.

2.0 INVESTMENT DESCRIPTION

The proposed expenditures in this ISD primarily involve upgrades to existing stations and feeders, the construction of new stations and feeders, and the conversion of feeders or feeder sections to higher voltage levels. The appropriate solution for each area is determined based on local system configuration and the nature of the identified capacity need. The following subsections describe the feeder, station, and electrification investments included in the proposed plan.

2.1 FEEDER INVESTMENTS

Feeder investments involve the redistribution of load through the construction of new feeders, or the modification or extension 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 feeder ties.

When feeders in a geographical area have been fully utilized, and station capacity exists, new feeders from Transformer Stations (TS) or Distribution Stations (DS) may be required to meet load capacity needs. An alternative to constructing new feeders is voltage conversion, which can increase available capacity on a feeder. This involves converting lower-voltage lines to higher-voltage lines by upgrading transformers, insulators, protective devices, clearances, and sometimes conductors. Compared with lower voltage lines, the higher voltage line has a greater load carrying capacity.

Table 3 below summarizes the total numbers of feeder investments each year by region. Furthermore, the following examples illustrate how system constraints can be addressed through a feeder investment. This table includes investments which have both station and feeder work.

Table 3 - Number of Feeder Investments by In-Service Year

Region	2028	2029	2030	2031	2032
North	2	1	2	0	0
Central	5	3	7	2	4
South	6	6	19	8	8
East	2	2	8	0	3
Total	15	12	36	10	15

2.1.1 EXAMPLE FEEDER INVESTMENT: "NEWPORT PDS LOAD RELIEF"

The northern area of the Six Nations of the Grand River First Nations Reserve is experiencing residential and small business load growth, particularly around Chiefswood Rd, Mohawk Rd, 2rd line and 4th Line. This community is currently served by a single 2.5 MegaVolt-Ampere (MVA) 27.6 kiloVolt (kV) to 8.32 kV Padmount Distribution Station (PDS). Figure 4 below depicts the current electrical configuration in this area served by the PDS, the area of load growth, as well as the nearby Caledonia TS M6 27.6kV feeder. This PDS transformer, as well as the 8kV distribution lines supplied from the PDS transformer, are currently operating at approximately 80% of their planning limit. This area has experienced a 33% load increase in the last 5 years, with an additional 20% growth forecasted by 2030. At that point, the PDS transformer is forecasted to exceed its planning limit, which can result in failure of the PDS transformer due to overloading and customer voltages to fall below acceptable limits (i.e. Canadian Standards Associated CAN-C235-83[R2015], and Hydro One's Conditions of Service).

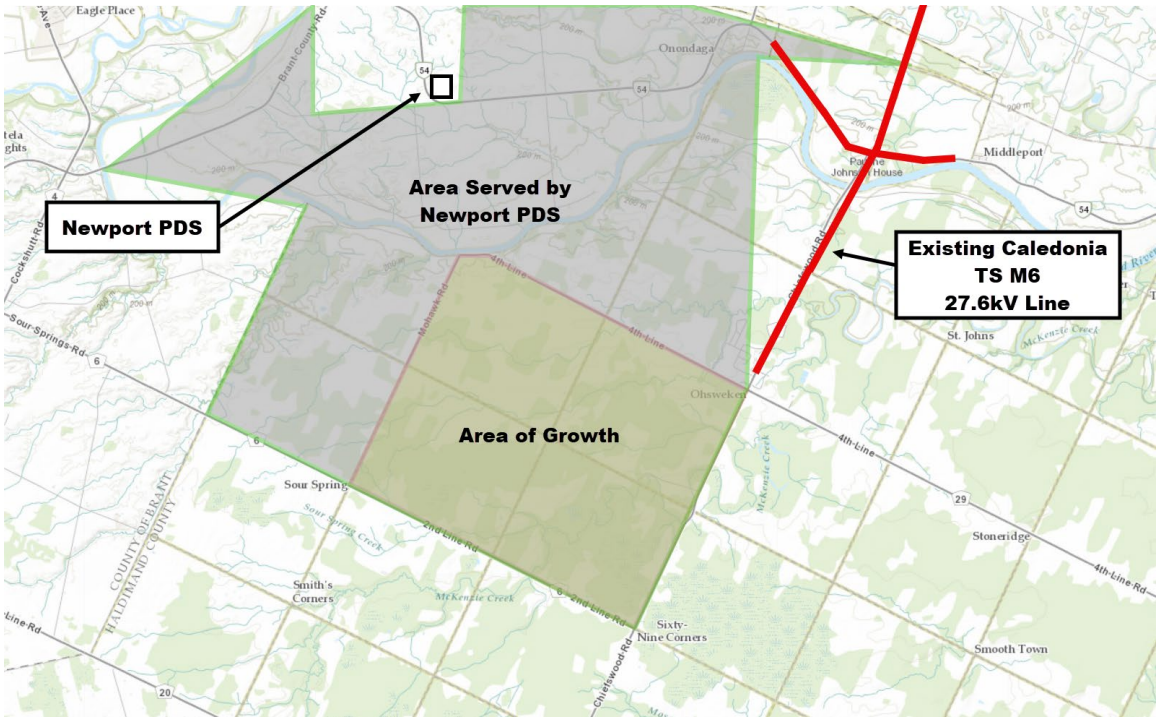


Figure 4: Geographical view of Newport PDS, Caledonia TS M6, and the areas of growth

In order to provide the Six Nations of the Grand River community with sufficient capacity, Hydro One is planning to voltage convert customers currently supplied by the Newport PDS 8.32kV distribution line, to receive electricity from a higher voltage 27.6kV distribution line in the area. This is accomplished by extending the nearby Caledonia TS M6 27.6kV distribution line to near the PDS transformer location and connecting customers to the extended feeder. Figure 5 below depicts the route of the 27.6kV feeder extension from Caledonia TS M6.

This voltage conversion creates additional capacity in two ways:

1) Customers who are now supplied from the higher voltage line will have available capacity for future growth from the new distribution line
2) Customers who remain on the PDS transformer will have available capacity for future growth as the total load on the PDS transformer has been reduced by supplying some customers currently fed from Newport PDS from the new line

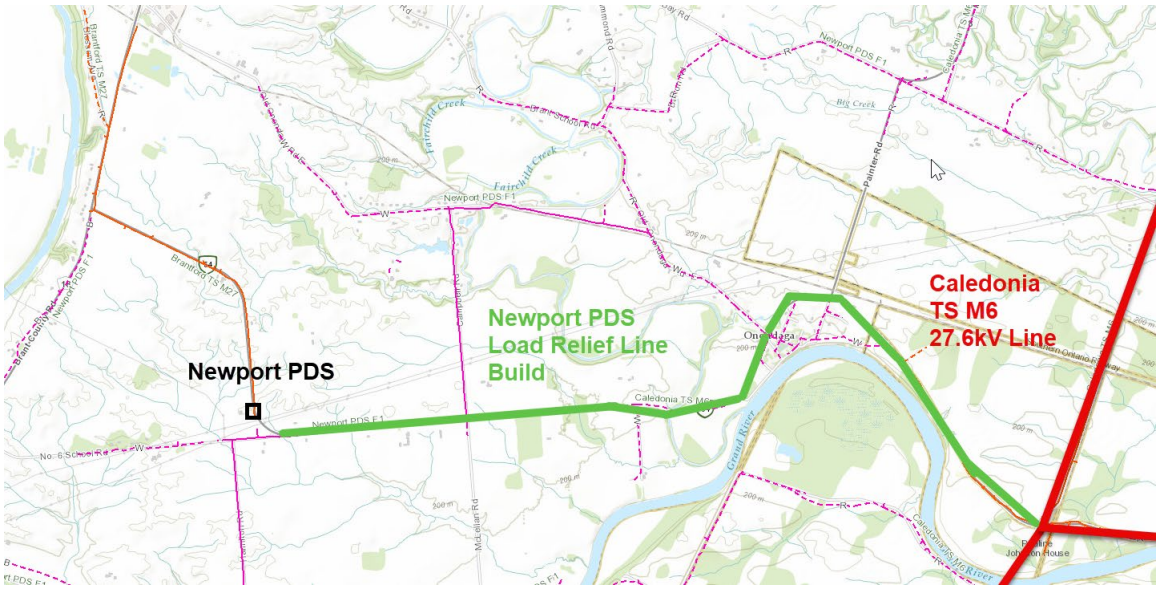


Figure 5: Routing for the Newport PDS Load Relief Project

2.1.2 EXAMPLE FEEDER INVESTMENT: "FERGUS TS M4 M8 LOAD RELIEF"

Rockwood is a community located in the Township of Guelph-Eramosa in Wellington County. The community is primarily served by Alectra Utilities, with Hydro One servicing some loads within Rockwood Village and the surrounding areas from the 8.32kV Rockwood Distribution Station. The subtransmission supply for this community comes from Fergus TS, located just outside the community of Fergus, using two 44kV feeders: the M4 and M8 feeders.

The M4 feeder runs approximately 22.5km before reaching Rockwood where it supplies an Alectra owned Municipal Station. In addition, it provides supply to Halton Hills Hydro and Milton Hydro in the areas located just south of Rockwood. The M8 feeder runs approximately 35km before reaching Rockwood, where it supplies Hydro One's Rockwood DS and an Alectra owned Municipal Station. The M8 feeder also supplies Guelph DS and Eramosa DS, which are further located upstream from Rockwood. The two 44kV feeders – M4 and M8 – also have tie points in Rockwood which allow for backup supply during contingencies.

Currently, the capacities of the two 44kV feeders are limited to approximately 15MW due to the long feeder length and the resulting end of line voltage performance. The load on

both 44kV feeders is expected to grow steadily over the next 5 years. In order to avoid low voltage issues at the end of the feeders, and to maintain operational flexibility, Hydro One is planning to install 44kV Pole mounted Voltage Regulators on both feeders. Figure 6 depicts the layout of both the M4 and M8 feeders, and the proposed locations of the 44kV voltage regulators. At the current rate of forecasted load growth, the capacities of the 44kV feeders are expected to be exhausted by 2032, and Hydro One is planning to pace the investment accordingly.

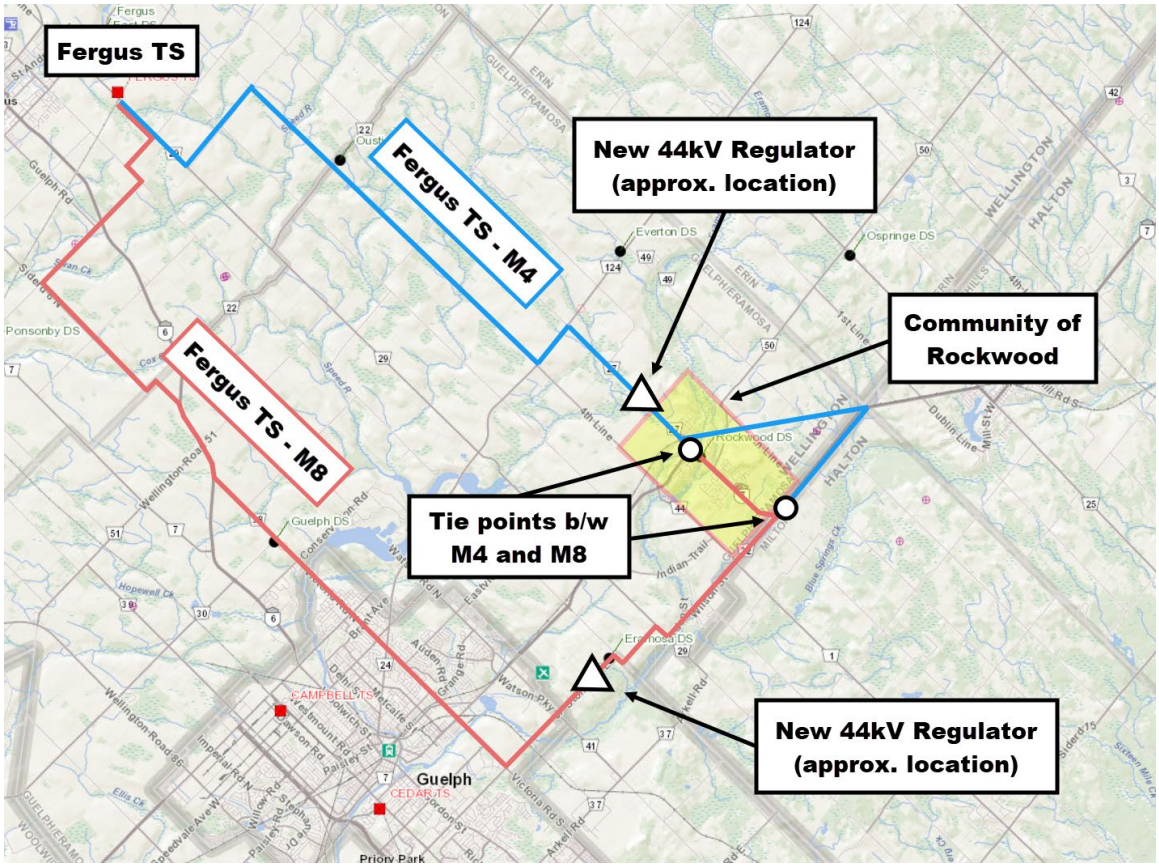


Figure 6: Fergus TS M4 and M8 feeder supply to Rockwood and proposed voltage regulator locations

2.1.3 EXAMPLE FEEDER INVESTMENT: "NORTHERN YORK REGION TS - 44KV FEEDER BUILD #4"

King City, located within the Township of King, is experiencing significant growth driven by new planned developments. In the subject area, Hydro One has already received requests for more than 1,000 new residential units. Additional residential lots are expected on the east side of Jane Street, along with commercial development – including three new schools – in the next 5 years. The area is primarily served by Eversley Distribution Station (DS), which is equipped with two 44kV-13.8kV 10MVA transformers and five 13.8kV distribution feeders.

The Kleinburg TS M23 is a 44kV sub-transmission feeder, which runs approximately 25km from Kleinburg TS, and provides electrical supply to Eversley DS and other larger commercial & industrial loads in and around King City. Figure 7 depicts the current 44kV feeder configuration in the area. Currently, this feeder is operating at 90% of its 30MW planning limit.

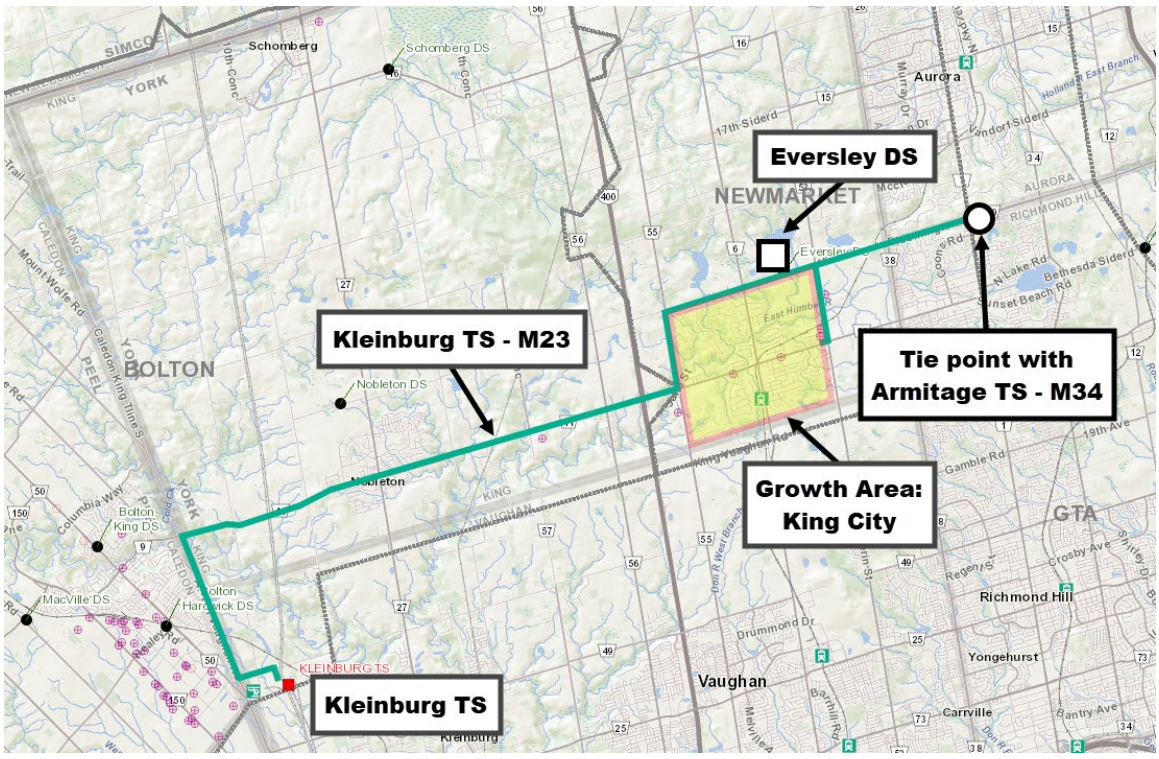


Figure 7: Existing configuration of Kleinburg TS – M23 and subject area of growth

In order to ensure sufficient capacity is available, Hydro One is planning to extend a new 44kV feeder from the planned new Northern York Transformer Station #1 and transfer Eversley DS from the existing Kleinburg TS M23 feeder. The route for the proposed new 44kV feeder is depicted below in Figure 8. This will provide load relief to Kleinburg TS M23, provide additional load capacity to enable growth in King City, and maintain load transfer capabilities during contingencies. At the current rate of load growth, the remaining capacity on the M23 is expected to be exhausted by 2030. The new Northern York Transformer Station #1 has an expected in-service date of Q1 2031, and will provide additional 44kV feeder capacity in the area. Hydro One is planning to pace the line extension in accordance with the timelines for the new Transformer Station.

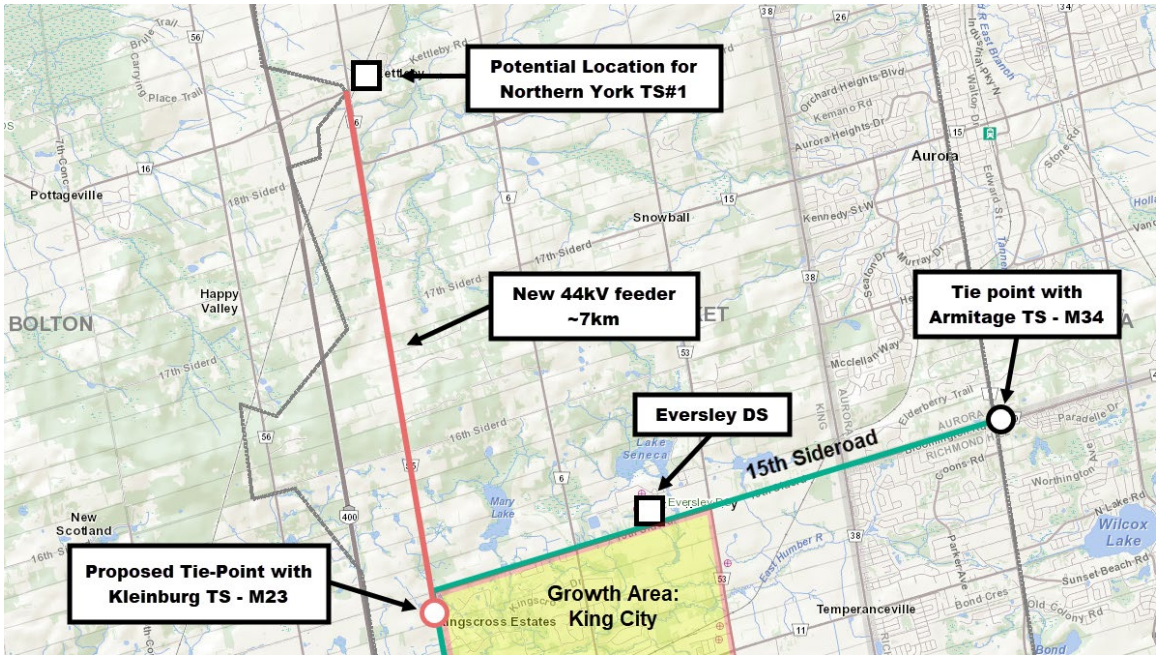


Figure 8: Proposed route of new 44kV feeder extension from Northern York TS #1

2.1.4 EXAMPLE FEEDER INVESTMENT: "JARVIS TS M3 RECONDUCTORING"

Jarvis TS M3 is a 27.6kV feeder from Jarvis TS that serves a few rural communities, and the southern portion of the Six Nations of the Grand River First Nations Reserve. The area within the reserve served by the M3 feeder is experiencing load growth, particularly in residential and commercial developments.

The M3 feeder runs for 19 km, primarily along Haldimand Road 55, from the Transformer Station before reaching the First Nations Reserve and branching off into different sections that supply the various areas within the community. The 16km section along Haldimand Road 55 is currently equipped with 3/0 Aluminum Conductor Steel Reinforced (ACSR) conductors, which limits the ability to load the M3 feeder. Based on historical loading data, this section is loaded to more than 65% of the 15.5MW planning limit of the conductor. An additional 6.3MW of new load is expected to materialize over the next 5 years, which will exceed the planning limit.

To avoid overloading the conductors of the existing M3, and to ensure sufficient load capacity is available to accommodate the expected load growth withing the Six Nations of the Grand River community, Hydro One is planning to reconductor a 16km section of the existing line up to the supply point of the community. The existing 3/0 ACSR conductors will be replaced with 556 ACSR conductors to provide additional load capacity on the Jarvis TS M3 feeder. The subject section of line being reconductored along Haldimand Road 55 is depicted in Figure 9. Hydro One anticipates that the remaining available capacity will be exhausted by 2030 and is planning to complete the Jarvis TS M3 Reconductoring project by that year.

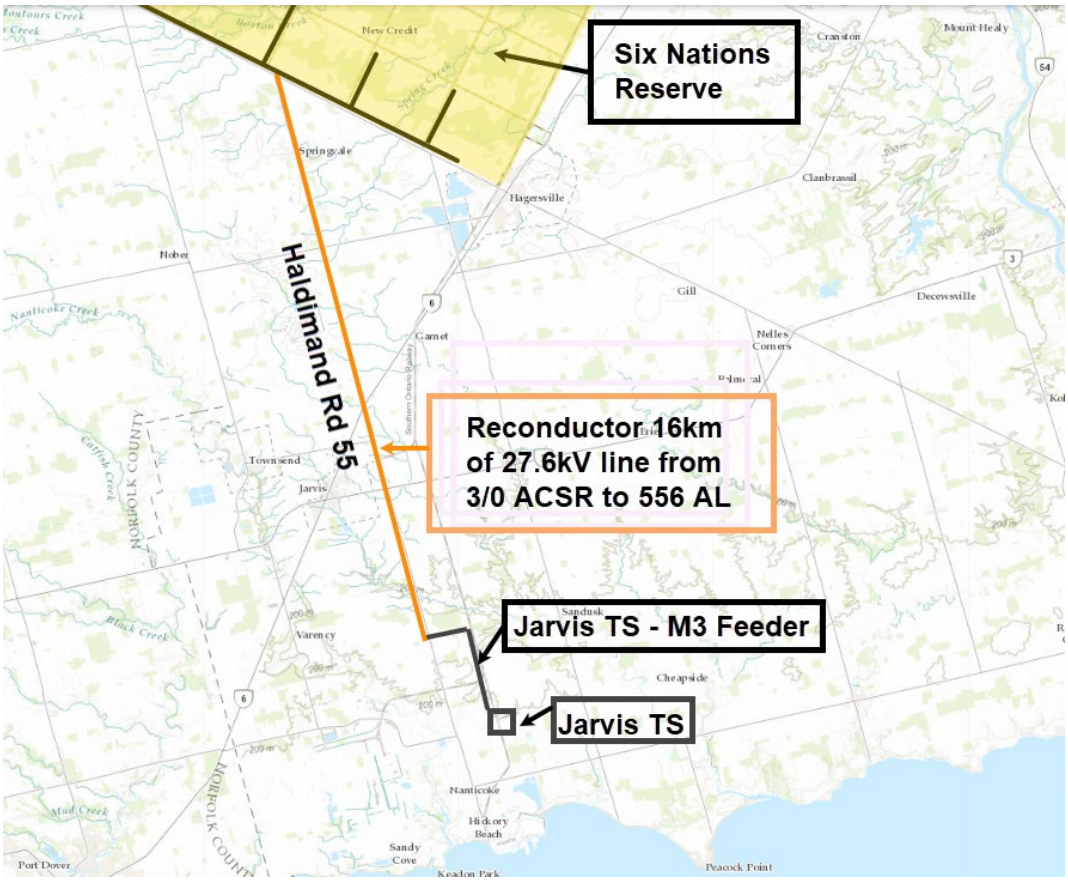


Figure 9: Subject section of the Jarvis TS M3 feeder that requires reconductoring

2.2 STATION INVESTMENTS

Station upgrade investments involve the modification of existing stations or the construction of new stations. If 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 upgrading existing infrastructure does not meet the load capacity needs, it may be necessary to construct a new station. Building a new station offers the benefit of additional feeder capacity to reduce loading on existing feeders. Additionally, this has the potential to improve load transfer capabilities which allow more operational flexibility and improve reliability during contingencies. Where new stations are proposed, SCADA enablement of the new facilities is included to provide remote loading data, faster fault location, operational flexibility, and contribute to the enablement of future DERs. Table 4 below summarizes the total number of station

investments each year by region. This table includes investments with both station and feeder work forecasted over the 2028-2032 rate period. Furthermore, the following examples illustrate how system constraints can be addressed through a station investment.

Table 4 - Number of Station Investments by In-Service Year

Region	2028	2029	2030	2031	2032
North	1	1	0	1	1
Central	14	9	5	1	8
South	10	13	1	6	5
East	5	7	6	6	4
Total	30	30	12	14	18

2.2.1 EXAMPLE STATION INVESTMENT: "NEW FERGUS DS"

Residential subdivision activity is expected to significantly expand in the community east of Elora and west of the community of Fergus – located north of the city of Guelph – over the next 5 years. In the subject area, Hydro One has already received requests for the design and construction of more than 500 residential lots on Beatty Line South of County Road 15. An additional 500 lots are also expected to be built in the northern part of the community within 5 years, with further 1000+ lots in the longer term. Including a proposed commercial block, approximately 5MW of new load is expected to materialize over the next 5 years.

The subject area is supplied by Elora Union DS, with two 8.32kV feeders – the F2 and the F4 – in the vicinity of the development lands. The existing Elora Union DS and its existing feeders are depicted below in Figure 10. Both feeders are loaded at over 80% of their 4MW planning limits. Furthermore, the existing transformer at Elora Union DS is loaded at 90% of its 6.25MVA planning limit. The expected load of 5MW, due to the proposed residential and commercial development, will far exceed the remaining capacity of the station and the feeders in the area. Furthermore, the forecasted high loading on the feeders will restrict load transfer capabilities, overload existing protection devices, and cause power quality issues.

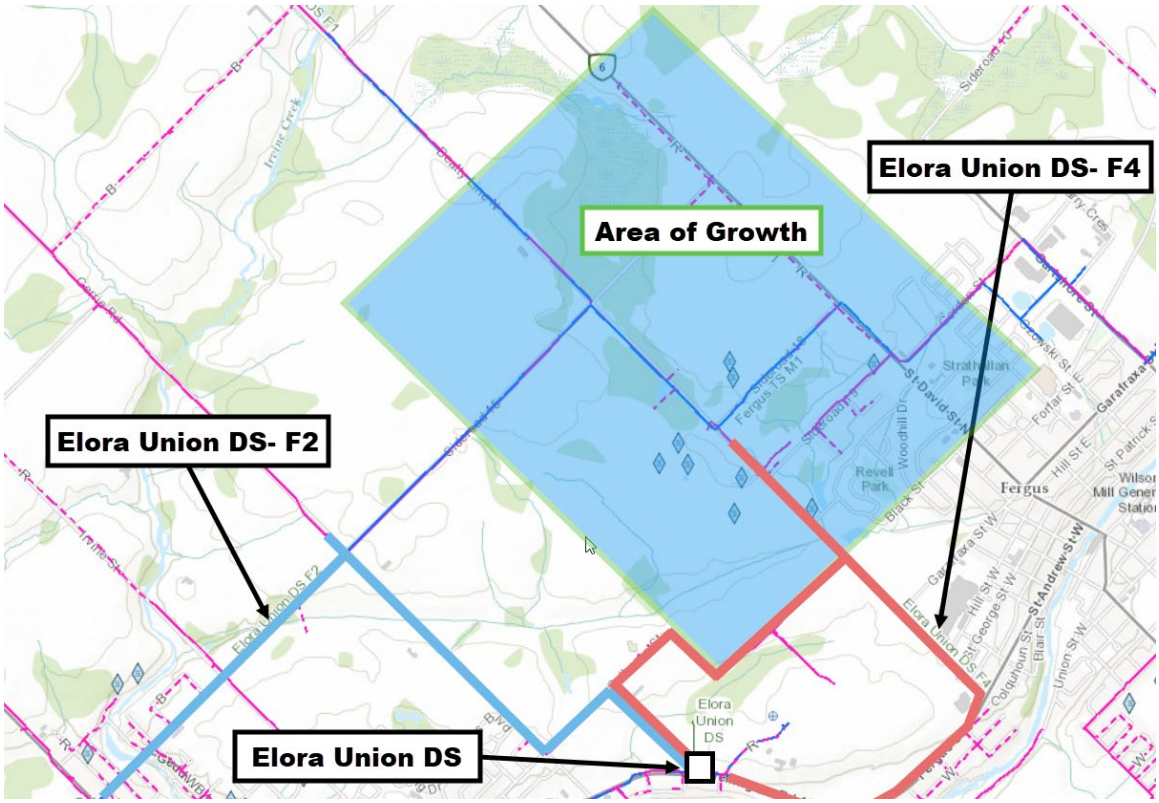


Figure 10: Elora Union DS – Existing Distribution Facilities

In order to accommodate the load growth, a new DS will be built near the development lands, as shown in Figure 11. Building a new DS, combined with construction of additional 8.32kV distribution lines from the DS, will allow reconfiguration of the existing feeder lines in the vicinity to provide additional capacity in the area, and will provide load relief to the existing feeders. The new DS will be able to provide capacity to support the forecasted load growth and limit the overloading of the transformer at Elora Union DS, thereby reducing the risk of failure of existing infrastructure. At the current rate of new home connections, Hydro One anticipates that the remaining available capacity in the area will be exhausted by 2028 and is planning to complete the New Fergus DS project by 2028.

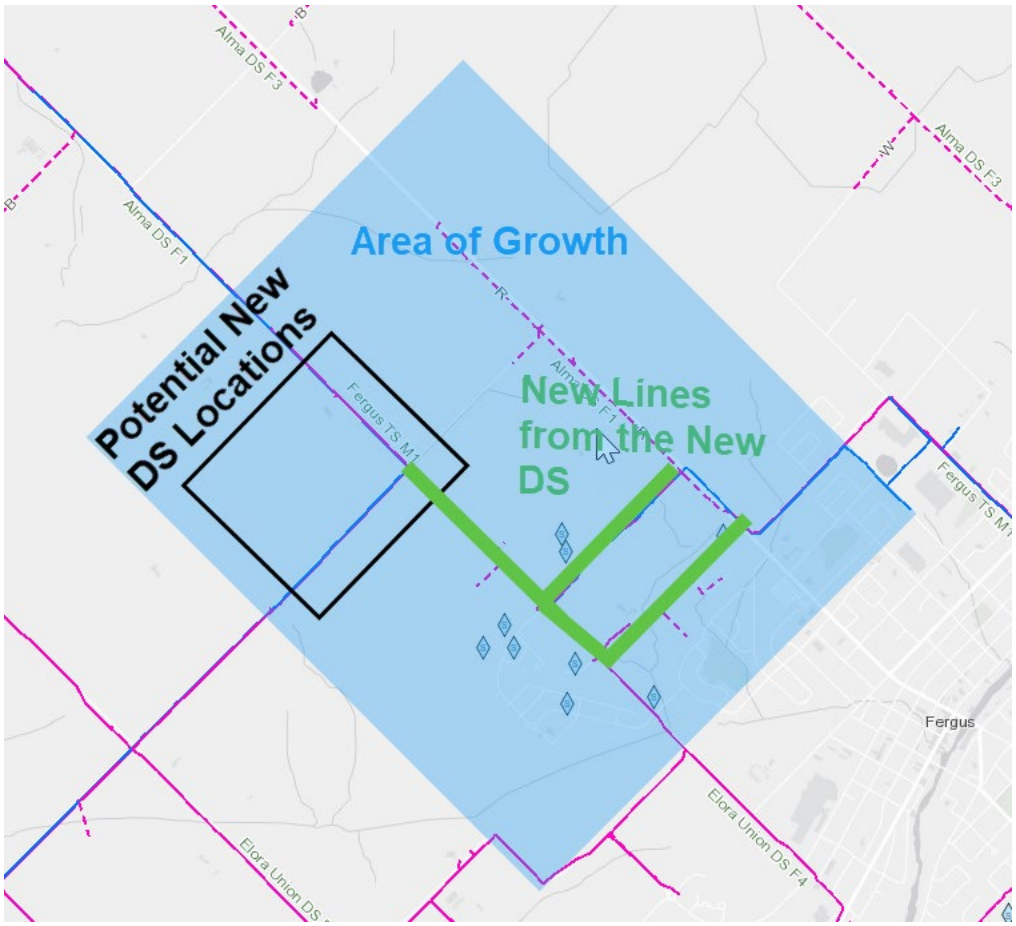


Figure 11: New Elora DS – Existing and Proposed Distribution Facilities

2.2.2 EXAMPLE STATION INVESTMENT: "CRAIGHURST DS TRANSFORMER UPGRADE"

Craighurst DS is located in the community of Craighurst – within the Township of Oro-Medonte – and it supplies the community, along with communities in the Township of Springwater. Within the community of Craighurst, Hydro One has received requests for the design and construction of more than 100 residential lots, and a pumping station, on east side of Penetanguishene Road north of Horseshoe Valley Road West. An additional 270+ residential lots are also expected to be built within the subject development area within the next 5 years, with further residential lots on the south side of Horseshoe Valley Road West in the longer term. Including a proposed school block, approximately 2MW of new load is expected to materialize over the next 5 years. Figure 12 depicts the subject

development area, the existing feeder infrastructure currently servicing the area, and the current location of the Craighurst DS.

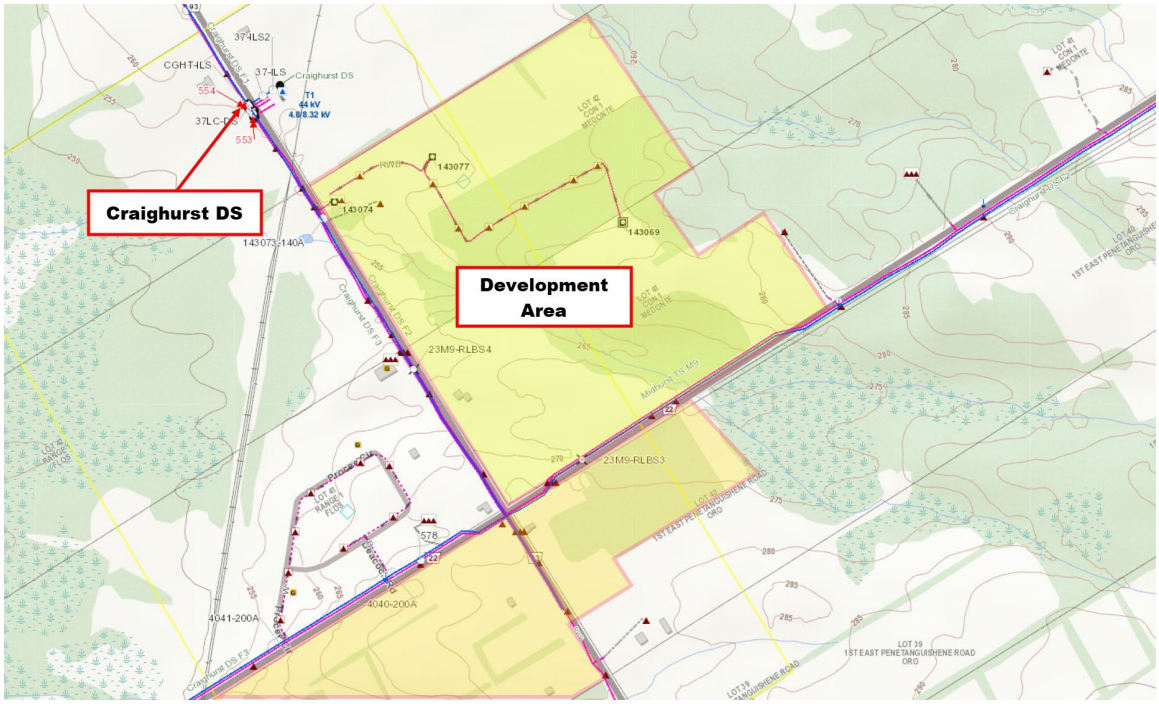


Figure 12: Craighurst DS – Existing Distribution Facilities and Development Area

The 8.32kV Distribution Station is equipped with a 5MVA 44kV-8.32kV transformer and three feeders. Currently, the transformer is loaded beyond 90% of its planning limit of 6.25MVA. The expected load of 2MW, due to the proposed residential lots and school, will exceed the remaining capacity of the transformer.

To accommodate the load growth, the existing 5MVA 44kV-8.32kV transformer will be upgraded to a 10MVA 44kV-8.32kV transformer. Upgrading the transformer will avoid overloading of the transformer at Craighurst DS, reducing the risk of failure of the existing infrastructure. At the current rate of new home connections, Hydro One anticipates that the remaining available capacity will be exhausted by 2029 and is planning to complete the Craighurst DS Transformer Upgrade project accordingly.

2.3 SECONDARY ELECTRIFICATION PROGRAM

Electrification introduces new load growth to the distribution system, with EV adoption expected to be the dominant driver of capacity constraints at service transformers, which are often the first assets to experience overloading as EV penetration increases. In response, Hydro One has developed the Secondary Electrification Program to proactively address these impacts.

To assess the impacts, Hydro One applied the Electric Power Research Institute (EPRI)'s Hotspotter Tool to evaluate localized overload risks across approximately 375,000 service transformers with available metering and asset data. The Hotspotter Tool is a probabilistic grid impact analysis platform that identifies transformers at risk of thermal overload due to increasing EV adoption. It operates at the individual service transformer level, simulating hourly EV charging demand against remaining capacity of the transformer. The analysis integrates smart meter data to establish baseline transformer loading profiles, combined with EV charging assumptions informed by Hydro One's residential energy survey information, industry research, and smart meter data disaggregation results. The Hotspotter tool is based on a probabilistic model, which reflects realistic charging behaviour, including charging diversity and timing, rather than relying on uniform or worst-case charging assumptions across the system.

Using EV adoption projections informed by federal EV adoption forecasts[1] available at the time of the analysis and together with charging behaviour assumptions grounded in observed customer data, the Hotspotter analysis identified service transformers that are highly likely to experience strain as adoption increases during the 2028-2032 planning period. The adoption forecast was subsequently adjusted to reflect updated expectations regarding the pace of EV uptake. After accounting for the impacts of the New Connections program described in DSP Section 3.11, D-SA-02, which will replace certain high-risk transformers through customer-driven upgrades, and the anticipated benefits of the EV

[1] Environment and Climate Change Canada, *Canada's Electric Vehicle Availability Standard (regulated targets for zero-emission vehicles)*, available at: https://www.canada.ca/en/environment-climate-change/news/2023/12/canadas-electric-vehicle-availability-standard-regulated-targets-for-zero-emission-vehicles.html.

managed charging program, which may reduce transformer loading and defer or eliminate replacement needs, Hydro One identified approximately 2800 service transformers that are highly likely to experience overloading.

To estimate the associated investment requirements, Hydro One used an average unit cost per service transformer, based on historical replacement and upgrade information. The unit cost reflects the transformer replacement and associated secondary work that is commonly required as part of the upgrade.

3.0 OUTCOMES

3.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 5 - Outcome Summary

Customer Focus	• Ensure adequate capacity within the distribution system to meet existing and forecast customer electricity needs to enable economic development. • Ensure acceptable power quality is provided to customers. • Enable timely customer connections by proactively managing system loading and capacity constraints.
Operational Effectiveness	• Maintain the safe and effective operation of the distribution system by avoiding the overload of distribution assets • Reduce the risk of lengthy customer outages caused by the failure of overloaded assets. • Maintain service delivery within appropriate voltage ranges and power quality standards.
Public Policy Responsiveness	• Comply with Section 3.3 of the DSC, which requires distributors to plan the system to accommodate reasonable forecast load growth.

4.0 EXPENDITURE PLAN

Tables 6 and 7 summarize Hydro One and Orillia RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 planning period. There are no planned and forecast net capital expenditures for Peterborough RZ. A detailed breakdown of each investment can be found in Appendix A.

Table 6 - Hydro One - Investment Expenditures

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	505.8	744.0	278.7	314.0	401.2	287.7	254.0	1,535.5
Less Removals	40.2	75.5	28.5	31.1	43.4	28.0	27.0	158.0
Less Capital Contributions	0.0	1.7	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**465.7**	**666.8**	**250.2**	**282.9**	**357.7**	**259.7**	**227.0**	**1,377.4**

Table 7 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	7.81	0.20	0.98	0.0	Embedded in Hydro One Networks		
Less Removals		0.33	0.0	0.85	0.0			
Less Capital Contributions		0.0	0.0	0.0	0.0			
Net Capital Expenditures		**7.48**	**0.20**	**0.13**	0.0			

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be $201.1M higher than planned. This increase is driven by load growth materializing earlier and at a greater rate than forecasted when the plan was approved, requiring a higher volume of investments than originally anticipated. Since 2023, Hydro One has experienced an increase in customer connections and broader regional growth across its service territory, resulting in a larger number of stations, feeders and assets reaching, or forecasted to reach, their planning limits earlier than anticipated. Under this program, Hydro One delivered 123 material investments compared to 93 planned, including additional feeder builds and station reinforcements advanced from future years, and other upgrades identified through updated planning assessments.

[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Actual" refers to Actual (2023-25) and Forecast (2026-27) expenditures.

In addition to an increase in volume of investments, expenditures have also increased relative to the assumptions underlying the approved plan as a result of various factors including higher material costs, supply chain disruptions, and commodity inflation, as discussed in SPF Section 1.8, Managing Market Cost Pressures. In response to these challenges, Hydro One prioritized and paced investments based on the extent and timing of emerging system needs. However, the number and urgency of load-driven capacity constraints ultimately required additional expenditures to maintain system reliability, customer service quality, and the ability to connect new load across the distribution system.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, Hydro One expects to deliver 190 material System Upgrades Due to Load Growth Investments, which encompasses 88 feeder investments, 51 station investments, 50 investments with both feeder and station work, and the secondary electrification program. A detailed breakdown of these material investments is provided in the appendices for each Hydro One rate zone. No material investments have been identified for the Orillia and Peterborough rate zones; associated expenditure tables for these areas are provided in Appendices B and C, respectively.

The forecast for material Investments Driven by Load Growth is developed based on historical unit costs and the expected volume of work over the planning period. For distribution feeder projects, estimated costs are derived by applying historical cost per kilometer to the approximate length of proposed feeder routes. For distribution station projects, cost estimates are based on unit costs informed by historical project experience, including the number of transformer banks and recloser specifications. Where investments include both feeder and station components, the total estimated cost reflects the combination of both station and feeder elements.

The factors influencing the cost of the investment include:

- The number, configuration, and length of distribution circuits on the subject section of line that is being upgraded or newly built
- The extent of forestry and vegetation management required along the proposed feeder path

- The quantity and type of equipment required on the new poles, such as switches, capacitor banks, voltage regulators, protection & control equipment, and SCADA devices
- The extent of underground infrastructure and associated civil works required, including cables, duct banks, and grounding systems
- Property access (i.e. easement, rights-of-way) and real estate acquisition costs
- Site specific conditions, including constructability, topography, geotechnical conditions, environmental constraints, and accessibility
- Cost of materials and major equipment, including transformers, switchgears, protection equipment, SCADA equipment, and station structures
- Other requirements from the road authority or property owner impacted by the load growth projects

During the 2028-2032 planning period, Hydro One plans to initiate investments driven by load growth in alignment with identified need dates based on forecasted demand and considers the resulting investment pacing to be prudent. The projects identified in this ISD will progress through various project stages with expenditures reflecting the natural sequencing of activities.

Higher expenditures in 2030 represents a ramp-up of construction activities for projects planned to be in-service by 2030, as well as ongoing design work for projects with later need dates within the planning period. In subsequent years, expenditures continue to align with the progression of design and construction activities required to support projects scheduled for completion in 2031 and 2032.

5.0 ALTERNATIVES

As indicated in DSP Section 3.7, subsection 3.7.3.4, System Upgrades Driven by Load Growth are considered non-discretionary because they are required to meet growing customer demand and maintain system reliability. However, the timing of individual investments may be subject to evolving load forecasts, customer requirements, and other external factors that affect when capacity constraints materialize.

ALTERNATIVE 1: DO NOTHING

This alternative was rejected as it does not meet the Distribution System Code requirement to plan and build for reasonable forecast load growth and exposes the system and Hydro One's customers to unacceptable levels of risk. This alternative would result in load growth continuing without investment until system constraints result in asset overloading, equipment failure, or power quality issues, requiring Hydro One to respond reactively on an emergency basis. Under this approach, increasing demand would place sustained stress on existing lines, transformers, and station equipment, accelerating asset degradation, reducing asset life, and increasing the likelihood of unplanned outages. Overloading may also create protection coordination issues, which may negatively impact system reliability and safety, while limiting operational flexibility for planned outages and maintenance. Customers would experience more frequent and longer outages, along with potential voltage and power quality issues.

ALTERNATIVE 2: NON-WIRES SOLUTIONS (ADOPTED WHERE COST-EFFECTIVE, SEE APPENDIX D)

Consistent with the OEB's NWS Guideline for Electricity Distributors and Benefit-Cost Analysis Framework for Addressing Electricity System Needs, Hydro One has integrated an NWS assessment into its Planning Process. The process evaluates the suitability of NWS alternatives by comparing their ability to address identified system needs relative to the traditional "wires" alternative, considering timing, cost-effectiveness, and the nature of the underlying need. The NWS process is focused on load growth investments, as NWS are particularly well suited to address system needs driven by peak demand loading. Additional details regarding Hydro One's NWS process are provided in DSP Section 3.6, subsection 3.6.5. Application of this process identified 16 projects for which NWS solutions are expected to defer traditional infrastructure investments beyond the 2028-2032 period. Collectively, these deferrals represent approximately $103M of investment. The resulting list of projects selected for execution as NWS within this filing can be found in Appendix D. In addition to these 16 projects, NWS is actively being used to defer one project, SS-01.102 “Kashabowie HVDS”, from the current 2023-2027 rate period to within the 2028-2032 period.

ALTERNATIVE 3: SYSTEM UPGRADES TO MEET LOAD GROWTH (RECOMMENDED)

This alternative involves proceeding with the identified investments to address system needs based on forecasted load growth, including proceeding with the Secondary Electrification Program. The recommended plan satisfies Section 3.3 of the DSC, which requires distributors to plan and expand their systems in response to reasonable forecast load growth. Proceeding with the required system upgrades to maintain loading on assets within asset capabilities ensures delivery of power to customers within acceptable industry power quality standards and maintains reliability by preventing asset overloads that increase risk of failure.

Throughout the 2028-2032 period, Hydro One will continue to evaluate load growth investments through its NWS screening process while further refining the capabilities necessary to identify, evaluate, and implement NWS solutions. To provide operational flexibility to implement its NWS program and to deploy additional cost-effective NWS solutions as new system needs emerge, Hydro One is proposing an NWS Operational Solutions Variance Account to record variances between forecast and actual NWS expenditures. Additional details regarding the proposed account are provided in Exhibit G-01-03, Subsection 9.4.

6.0 EXECUTION RISK AND MITIGATION

Risks that can impact the timing 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. Similarly, construction of new or upgraded distribution feeder facilities requires permits (i.e. municipalities, conservation authorities) and easements. 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. Material delays related to lead times for critical components, such as transformers and electronic equipment, caused by supply chain conditions can also jeopardize project in-service dates.

This risk will be mitigated by maintaining communications between supply chain and vendors, combined with the ability to pre-order components when required.

The timing and magnitude of future load growth may differ from the current forecast projections due to factors such as economic conditions, customer development schedules, and changes in customer demand. As a result, actual load growth in the 2028-2032 planning period may materialize faster or slower than anticipated, potentially affecting the timing of System Upgrades Driven by Load Growth investments. To manage this uncertainty, Hydro One continuously monitors system loading and customer developments and updates local load forecasts as necessary to support prudent investment decisions. This ongoing monitoring enables Hydro One to identify areas where load growth is materializing as forecast, accelerating, or progressing more slowly than anticipated, and to adjust the timing and prioritization of investments accordingly. Through this adaptive planning approach, Hydro One can advance investments where needs emerge earlier than forecast, and defer investments where growth materializes later than anticipated, helping ensure that infrastructure investments are made when required.

APPENDIX A - DESCRIPTION OF INVESTMENTS – HYDRO ONE

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
City of Owen Sound Tie-Line Reinforcement	SS-01.1	Build new 44kV:4.16kV 3MVA Padmounted DS with two feeder positions and extend the Owen Sound TS M21 44kV feeder by approximately 1 kilometer to support load growth in the Owen Sound area.	9,872	Central	0.0	1.0	3.9	0.0	0.0
Beaverton M29 extension	SS-01.2	Extend Beaverton TS - M29 feeder by approximately 4km, along with conductor upgrades, to support load growth in the Uxbridge area.	4,612	Central	2.0	0.0	0.0	0.0	0.0
King City DS - New Station & Feeders	SS-01.3	Build a new single-bank 44kV:13.8kV 10MVA DS with two feeder positions to support load growth in the Town of King.	4,242	Central	5.0	0.0	0.0	0.0	0.0
Port Perry Area Load Growth	SS-01.4	Build new 44kV:8.32kV 3MVA Padmounted DS with two feeder positions to support load growth in the Port Perry area.	1,026	Central	0.0	0.5	2.5	0.0	0.0
Aspdin DS Transformer Upgrade	SS-01.5	Upgrade the existing 44kV:12.5kV 6MVA transformer at Aspdin DS to 10MVA to support load growth in the Aspdin area.	3,330	Central	0.5	3.4	0.0	0.0	0.0
Muskoka TS M1-M5 New Tie Line	SS-01.6	Extend Muskoka TS - M5 44kV feeder by approximately 15km to support load growth in the Muskoka region.	10,526	Central	10.1	0.0	0.0	0.0	0.0
Uxbridge DS #2 Upgrade	SS-01.7	Upgrade the existing 44kV:8.32kV 5MVA transformer at Uxbridge DS to 10MVA to support load growth in the Uxbridge area.	2,143	Central	1.0	0.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Craighurst DS Transformer Upgrade	SS-01.8	Upgrade the existing 44kV:8.32kV 5MVA transformer at Craighurst DS to 10MVA to support load growth in the Craighurst area.	1,782	Central	0.5	3.4	0.0	0.0	0.0
Solina DS Upgrade and Feeder Expansion	SS-01.9	Build a second 44kV:27.6kV 10MVA transformer bank with two new feeders in Solina DS, to support load growth in the Courtice area.	3,973	Central	4.0	0.0	0.0	0.0	0.0
Stayner TS - M5 Padmount Transformer	SS-01.10	Build new 44kV:8.32kV 3MVA Padmounted DS with two feeder positions to support load growth in the Stayner area.	1,363	Central	0.0	0.6	2.0	0.0	0.0
Muskoka TS M1 Reconductor	SS-01.11	Reconductor 12.7 kilometers of 44kV line on the Muskoka TS - M1 feeder to support load growth in the Muskoka area.	10,526	Central	0.0	0.0	1.2	3.0	3.0
Wilson TS M11 44kV Line Extension	SS-01.12	Extend Wilson TS M11 44kV feeder by approximately 5km to support load growth in the Clarington area.	3,015	Central	0.5	4.7	0.0	0.0	0.0
Meaford TS M2 Conductor Refurbishment Load Growth	SS-01.13	Reconductor approximately 2.5 kilometers of 44kV line on the Meaford TS M2 44kV feeder to support load growth in the Meaford and Thornbury areas.	5,996	Central	0.0	0.3	2.4	0.0	0.0
Owen Sound TS M26 Conductor Refurb Load Growth	SS-01.14	Reconductor approximately 6 kilometers of 44kV line on the Owen Sound TS M26 44kV feeder to support load growth in the Owen Sound area.	3,916	Central	0.0	0.3	2.4	0.0	0.0
Lora Bay DS	SS-01.15	Build a new single-bank 44kV:8.32kV 7.5MVA DS with three feeder positions and extend the Meaford TS M2 44kV feeder by	2,428	Central	3.6	0.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		approximately 0.5 kilometer to support load growth in the Lora Bay area.							
Douglas Point TS M1 44 kV Feeder Regulation	SS-01.16	Install 44kV regulators on Douglas Point TS M1 44kV feeder to support load growth and voltage support in the Port Elgin and Southhampton areas.	2,699	Central	1.3	0.0	0.0	0.0	0.0
Holland Centre RS 44kV Pole Platform Regulator	SS-01.17	Install 44kV regulators on Owen Sound TS M26 44kV feeder to support load growth and voltage support in the Berkeley and Markdale areas.	3,916	Central	0.0	0.1	1.3	0.0	0.0
Footes Bay DS Transformer Upgrade	SS-01.18	Upgrade the existing 44kV:12.5kV 6MVA transformer at Footes Bay DS to 10MVA to support load growth in the Footes Bay community.	2,148	Central	0.5	3.4	0.0	0.0	0.0
Northern York Region TS - 44kV Feeder Build #1	SS-01.19	Build approximately 12.5 kilometers of new 44kV line to extend the M1 feeder from Northern York TS to support load growth in the Bradford-West Gwillimbury area.	8,955	Central	0.0	1.3	6.0	6.1	0.0
New Monaghan DS and feeders	SS-01.20	Build a new single-bank 44kV:8.32kV 10MVA DS with three feeder positions to support load growth in the Cavan-Monaghan township.	2,656	Central	2.3	0.0	0.0	0.0	0.0
Otonabee TS 27.6kV M9 Feeder Extension	SS-01.21	Extend Otonabee TS M9 27.6kV feeder by approximately 1km to support load growth in the Peterborough area.	1,852	Central	1.4	0.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
New Clarington DS and feeders	SS-01.22	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions to support load growth in the Clarington area.	7,359	Central	4.0	0.0	0.0	0.0	0.0
New Asphodel DS and feeders	SS-01.23	Build a new single-bank 44kV:8.32kV 10MVA DS with three feeder positions to support load growth in the Norwood area.	1,717	Central	4.0	0.0	0.0	0.0	0.0
Pointe Au Baril DS F1 New Tieline	SS-01.24	Extend Pointe Au Baril DS - F1 8.32kV feeder by approximately 3.5km, along with approximately 6km 1ph-3ph upgrade of Pointe Au Baril F1 and Alban DS F1 8.32kV feeders, to support load growth in the Parry Sound area.	1,247	Central	3.0	0.0	0.0	0.0	0.0
New Thunder Bridge DS and feeders	SS-01.25	Build a new single-bank 44kV:12.5kV 10MVA DS with three feeder positions and approximately 1km of 44kV line extension to support load growth in the Lindsay area.	1,583	Central	2.0	0.0	0.0	0.0	0.0
New Dalston DS and Feeders	SS-01.26	Build a new single-bank 44kV:8.32kV 10MVA DS with three feeder positions to support load growth in the Midhurst area.	3,069	Central	1.0	0.0	0.0	0.0	0.0
New York Durham DS and feeders	SS-01.27	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions and approximately 1km of 27.6kV line extension to support load growth in the Stouffville area.	8,561	Central	5.0	0.0	0.0	0.0	0.0
Grenfel DS Transformer Upgrade	SS-01.28	Upgrade the existing 44kV:8.32kV 3MVA transformer at Grenfel DS to 7.5MVA to support load growth in the Grenfel community.	1,272	Central	0.5	3.4	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Green Lane Load Growth	SS-01.29	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions to support load growth in the East Gwillimbury area.	3,490	Central	0.0	0.0	0.6	1.7	4.9
New Bloor DS and feeders Load Growth	SS-01.30	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions to support load growth in the Clarington area.	9,244	Central	0.0	0.0	0.6	2.3	7.5
Curve Inn DS 8.32KV T1 Upgrade	SS-01.31	Upgrade the existing 44kV:8.32kV 5MVA transformer at Curve Inn DS to 10MVA to support load growth in the Newcastle community.	664	Central	0.0	0.5	3.4	0.0	0.0
Blue Mountain DS New F3	SS-01.32	Extend Blue Mountain DS - F3 27.6kV feeder by approximately 1.5km to support load growth in the Blue Mountain area.	1,295	Central	0.0	0.1	1.0	0.0	0.0
Sunnidale Corners DS Transformer Upgrade	SS-01.33	Upgrade the existing 44kV:8.32kV 5MVA transformer at Sunnidale Corners DS to 7.5MVA to support load growth in the Stayner area.	1,363	Central	0.0	0.0	0.0	0.6	3.6
Snow Valley DS Upgrade - T2	SS-01.34	Build a second 44kV:27.6kV 10MVA transformer bank with two new feeders in Snow Valley DS, to support load growth in the Midhurst area.	634	Central	0.0	0.5	1.7	6.0	0.0
Utopia DS Upgrade - T2	SS-01.35	Build a second 44kV:27.6kV 10MVA transformer bank with two new feeders in Utopia DS, to support load growth in the Utopia area.	4,654	Central	3.5	0.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Bradford North DS Load Growth	SS-01.36	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions and approximately 3km of 27.6kV line extension to support load growth in the Bradford-West Gwillimbury area.	7,790	Central	3.1	0.0	0.0	0.0	0.0
Oro DS - Load Growth	SS-01.37	Upgrade the existing 44kV:8.32kV 6MVA transformer at Oro DS to 10MVA to support load growth in the Oro area.	1,445	Central	0.0	0.5	3.5	0.0	0.0
New Fergus Hill DS and Feeders	SS-01.38	Build a new single-bank 44kV:13.8kV 10MVA DS with two feeder positions and approximately 1km of 13.8kV line extension to support load growth in the Orillia area.	1,757	Central	0.0	0.0	0.6	1.7	4.9
Elmhurst & Homestead Load Growth	SS-01.39	Build a new dual-bank 44kV:27.6kV 10MVA DS with four feeder positions and approximately 2km of 27.6kV line extension to support load growth in the Keswick and Queensville communities.	6,566	Central	3.9	0.0	0.0	0.0	0.0
Lakefield DS #1 Transformer Upgrade	SS-01.40	Upgrade the existing 44kV:12.5kV 6MVA transformer at Lakefield DS #1 to 10MVA to support load growth in the Lakefield community.	2,303	Central	0.0	0.0	0.0	0.6	3.6
Springville DS Transformer Upgrade	SS-01.41	Upgrade the existing 44kV:8.32kV 5MVA transformer at Springville DS to 10MVA to support load growth in the Fairmount community.	1,241	Central	0.0	0.5	3.4	0.0	0.0
Waubaushene TS 8th Feeder	SS-01.42	Build approximately 6 kilometers of new 44kV line to extend the M8 feeder from	1,098	Central	0.6	5.1	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		Waubaushene TS to support load growth in the Midhurst area.							
Sutton DS#2 Load Growth	SS-01.43	Upgrade the existing 44kV:8.32kV 5MVA transformer at Sutton DS#2 to 7.5MVA to support load growth in the Georgina area.	1,246	Central	0.0	0.0	0.0	0.6	3.6
Northern York Region TS - 44kV Feeder Build #3	SS-01.44	Build approximately 6.5 kilometers of new 44kV line to extend the M3 feeder from Northern York TS to support load growth in the Township of King.	6,419	Central	0.0	0.0	0.0	0.7	6.5
Northern York Region TS - 44kV Feeder Build #4	SS-01.45	Build approximately 7.2 kilometers of new 44kV line to extend the M4 feeder from Northern York TS to support load growth in the Bolton area.	4,254	Central	0.0	0.6	2.8	2.8	0.0
Argyle DS Transformer Replacement	SS-01.46	Upgrade the existing 44kV:8.32kV 6MVA transformer at Argyle DS to 10MVA to support load growth in the Beaverton area.	876	Central	0.5	3.4	0.0	0.0	0.0
Huntsville DS T1 Upgrade	SS-01.47	Upgrade the existing 44kV:12.5kV 6MVA transformer at Huntsville DS to 10MVA to support load growth in the Huntsville area.	2,066	Central	0.0	0.5	3.4	0.0	0.0
Pleasant Point DS Transformer Replacement	SS-01.48	Upgrade the existing 44kV:12.5kV 5MVA transformer at Pleasant Point DS to 10MVA to support load growth in the Kwartha Lakes area.	1,313	Central	1.0	0.0	0.0	0.0	0.0
New Cheese Factory DS and feeders	SS-01.49	Build a new single-bank 44kV:12.5kV 10MVA DS with three feeder positions and approximately 2km of 12.5kV line extension to support load growth in the Lindsay area.	1,313	Central	0.0	0.0	0.6	2.3	7.9

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Mount Albert DS	SS-01.50	Build new 44kV:8.32kV 3MVA Padmounted DS with two feeder positions to support load growth in the Mount Albert area.	3,025	Central	0.0	0.5	1.9	0.0	0.0
Carling DS Transformer Upgrade	SS-01.51	Upgrade the existing 44kV:12.5kV 3MVA transformer at Carling DS to 10MVA to support load growth in the Shebeshekong Lake area.	718	Central	0.5	3.5	0.0	0.0	0.0
Cameron DS F3 expansion to Ops DS F1	SS-01.52	Extend Cameron DS - F3 12.5kV feeder by approximately 1km to support load growth in the Town of Lindsay.	1,583	Central	0.1	1.0	0.0	0.0	0.0
Gravenhurst DS Transformer Upgrade	SS-01.53	Upgrade the existing 44kV:12.5kV 6MVA transformer at Gravenhurst DS to 10MVA to support load growth in the Gravenhurst area.	1,397	Central	0.5	3.5	0.0	0.0	0.0
Baysville DS Transformer Upgrade	SS-01.54	Upgrade the existing 44kV:12.5kV 6MVA transformer at Baysville DS to 10MVA to support load growth in the Baysville area.	2,551	Central	0.5	3.5	0.0	0.0	0.0
Pineland DS Transformer Upgrade	SS-01.55	Upgrade the existing 44kV:12.5kV 7.5MVA transformer at Pinelands DS to 10MVA to support load growth in the Muskoka Lakes area.	1,725	Central	0.5	3.5	0.0	0.0	0.0
Jones DS Transformer Upgrade	SS-01.56	Upgrade the existing 44kV:12.5kV 6MVA transformer at Jones DS to 10MVA to support load growth in the Gravenhurst area.	885	Central	0.0	0.0	0.0	0.6	3.7

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Golden Beach DS Transformer Upgrade	SS-01.57	Upgrade the existing 44kV:12.5kV 6MVA transformer at Golden Beach DS to 10MVA to support load growth in the Bracebridge area.	1,180	Central	0.0	0.0	0.0	0.6	3.7
Parry Sound TS M1 Padmount Transformer	SS-01.58	Build new 44kV:12.5kV 3MVA Padmounted DS with two feeder positions to support load growth in the Nobel area.	718	Central	0.0	0.0	0.0	0.5	2.1
New Enfield TS #2- New 44KV Feeders	SS-01.59	Build 10 kilometers of new 44kV line to extend new feeders from Enfield TS#2 to support load growth in the Clarington area.	18,088	Central	0.0	0.0	0.0	1.0	9.9
Pembroke HVDS Conversion	SS-01.60	Build a new dual-bank 115kV:12.5kV 20MVA High-Voltage DS with two feeder positions, and 3km of 12.5kV line extension, to support load growth in the Pembroke area.	2,765	East	12.5	0.0	0.0	0.0	0.0
Alexander DS Load Growth	SS-01.61	Extend Alexander DS F2 and F3 27.6kV feeders by approximately 3.3 kilometers to support load growth in the Mississippi Mills area west of Ottawa.	2,565	East	0.5	3.4	0.0	0.0	0.0
Perth DS 8.32kV	SS-01.62	Upgrade the existing 44kV:8.32kV 3MVA transformer at Perth DS to 10MVA to support load growth in the Perth area.	947	East	4.5	0.0	0.0	0.0	0.0
Carleton Place #2 DS F2 Load Growth	SS-01.63	Voltage convert approximately 4.5 kilometers of Carleton Place DS#2 F2 8.32kV feeder by extending the Alexander DS F1 27.6kV feeder to support load growth in the Almonte area.	1,546	East	0.0	0.0	0.7	3.4	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Caintown DS 3 phase Lake St SW124 to 206	SS-01.64	Upgrade approximately 2 kilometers of Caintown DS F3 8.32kV feeder from single phase to three phase to support load growth in the Caintown area	389	East	0.0	0.2	1.4	0.0	0.0
Black Corners DS Load Growth	SS-01.65	Upgrade the existing 44kV:8.32kV 5MVA transformer at Black Corners DS to 7.5MVA to support load growth in the Perth area.	1,854	East	0.0	0.1	1.6	5.6	0.0
Jones Creek DS Load Growth	SS-01.66	Upgrade the existing 44kV:8.32kV 5MVA transformer at Jones Creek DS to 10MVA to support load growth in the Belleville area.	1,672	East	1.3	0.0	0.0	0.0	0.0
Shannonville DS Load Growth	SS-01.67	Build new 44kV:8.32kV 3MVA Padmounted DS with two feeder positions to support load growth in the Shannonville area.	951	East	0.0	0.4	3.1	0.0	0.0
Gardiner TS M14 Load Relief	SS-01.68	Extend Gardiner TS M15 44kVkV feeder by approximately 0.8 kilometers to support load growth in the Odessa area.	11,333	East	0.0	0.3	0.9	0.0	0.0
Arnprior Madawaska DS F1 Load Growth	SS-01.69	Extend Arnprior Madawaska DS F2 4.16kV feeder by approximately 1.3 kilometers to support load growth in the Town of Arnprior.	348	East	0.0	0.3	0.9	0.0	0.0
Carp DS T1 PLL	SS-01.70	Extend Carp DS F4 12.5kV feeder by approximately 2.9 kilometers to support load growth in the West Ottawa area.	825	East	0.0	2.1	1.7	0.0	0.0
South Gower DS	SS-01.71	Upgrade the existing 44kV:8.32kV 5MVA transformer at South Gower DS to 10MVA	1,496	East	0.0	0.3	4.5	3.5	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		to support load growth in the Kemptville area.							
Embrun DS	SS-01.72	Upgrade the existing 44kV:8.32kV 5MVA transformer at Embrun DS to 10MVA to support load growth in the Embrun area.	1,599	East	0.0	0.5	7.8	0.0	0.0
Lancaster DS Transformer Upgrade	SS-01.73	Upgrade the existing 44kV:8.32kV 5MVA transformer at Lancaster DS to 10MVA to support load growth in the Lancaster area.	915	East	0.0	0.0	0.0	0.6	3.6
Drummond DS T1 8.32kV	SS-01.74	Upgrade the existing 44kV:8.32kV 3MVA transformer at Drummond DS to 7.5MVA to support load growth in the Carleton Place area.	2,221	East	4.8	0.0	0.0	0.0	0.0
Fairfield DS Load Growth	SS-01.75	Upgrade the existing 44kV:8.32kV 5MVA transformer at Fairfield DS to 10MVA to support load growth in the Amherstview area.	1,004	East	3.9	0.0	0.0	0.0	0.0
Westbrook DS Load Growth	SS-01.76	Upgrade the existing 44kV:8.32kV 5MVA transformer at Westbrook DS to 10MVA to support load growth in the Westbrook comnunity.	1,514	East	2.0	0.0	0.0	0.0	0.0
Carrying Place DS Transformer Upgrade	SS-01.77	Upgrade the existing 44kV:8.32kV 5MVA transformer at Carrying Place DS to 10MVA to support load growth in the Carrying Place area.	1,634	East	0.5	3.4	0.0	0.0	0.0
West Lake DS Transformer Upgrade	SS-01.78	Upgrade the existing 44kV:8.32kV 5MVA transformer at West Lake DS to 10MVA to support load growth in the Picton area.	1,322	East	3.1	2.5	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Pinegrove DS Load Growth	SS-01.79	Upgrade the existing 44kV:12.5kV 6MVA transformer at Pinegrove DS to 10MVA to support load growth in the Arnprior west area.	2,228	East	0.0	0.6	1.3	5.4	0.0
Arnprior Elgin DS Load Growth	SS-01.80	Build approximately 3.3 kilometers of new 4.16kV line to extend the F2 feeder from Arnprior Airport DS to support load growth in the Town of Arnprior.	1,129	East	0.0	0.1	1.0	0.0	0.0
Napanee TS Upgrade Line Build	SS-01.81	Build approximately 6.5 kilometers of new 44kV feeder from Napanee TS to support load growth in the Napanee area.	5,591	East	0.0	0.0	0.0	1.2	10.7
Greenwood DS Load Growth	SS-01.82	Upgrade the existing 44kV:12.5kV 6MVA transformer at Greenwood DS to 10MVA to support load growth in the Pembroke area.	1,356	East	0.0	0.5	3.8	-0.3	0.0
New Carleton Place DS Load Growth	SS-01.83	Build a new single-bank 44kV:8.32kV 10MVA DS with four feeder positions, and approximately 6.5 kilometers of 44kV line extension, to support load growth in the Carleton Place area.	3,400	East	0.0	0.2	1.2	4.9	9.8
Embrun F3 to 28 kV Voltage Conversion	SS-01.84	Voltage convert approximately 2.8 kilometers of Embrun DS F3 8.32kV feeder by extending the Marionville DS F1 27.6kV feeder to support load growth in the Embrun area.	1,154	East	1.8	0.0	0.0	0.0	0.0
Picton DS F1 Load Growth	SS-01.85	Extend Picton DS F1 8.32kV feeder by approximately 1.5 kilometers to support load growth in the Picton area.	558	East	0.0	0.3	1.1	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Brockville 8kV Load Growth	SS-01.86	Build a new single-bank 44kV:8.32kV 10MVA DS with three feeder positions, and approximately 1 kilometer of 8.32kV line extension, to support load growth in the Brockville area.	2,692	East	5.9	0.0	0.0	0.0	0.0
Dewitt Corners DS F3 3ph Conversion Load Growth	SS-01.87	Upgrade approximately 9 kilometers of Dewitt Corners DS F3 8.32kV feeder from single phase to three phase to support load growth in the Tay Valley area	570	East	0.0	0.0	0.0	0.7	2.0
Cobden DS SCADA Enablement Load Growth	SS-01.88	Install fan monitoring and SCADA telemetry at Cobden DS to provide additional capacity to support load growth in the Cobden area.	2,261	East	0.2	1.0	0.0	0.0	0.0
Dewitt Corners DS Load Growth	SS-01.89	Upgrade the existing 44kV:8.32kV 7.5MVA transformer at Dewitt Corners DS to 10MVA to support load growth in the Perth area.	2,953	East	0.0	0.0	0.0	0.9	6.5
New DS in Perth Load Growth	SS-01.90	Build a new single-bank 44kV:8.32kV 10MVA DS with four feeder positions, and 2km of 8.32kV line extension, to support load growth in the Perth area.	947	East	1.8	5.3	2.2	0.0	0.0
Odessa DS Load Growth	SS-01.91	Upgrade the existing 44kV:8.32kV 5MVA transformer at Odessa DS to 10MVA to support load growth in the Odessa area.	1,707	East	0.7	3.2	3.2	0.0	0.0
Brighton 4kV System relief	SS-01.92	Build new 44kV:4.16kV 3MVA Padmounted DS with two feeder positions to support load growth in the Shannonville area.	1,002	East	0.0	0.1	1.5	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Manotick DS F3 Build and SCADA	SS-01.93	Extend Manotick DS F3 8.32kV feeder by approximately 3.5 kilometers to support load growth in the Manotick area.	979	East	6.9	0.0	0.0	0.0	0.0
Chesterville Frood DS Upgrade	SS-01.94	Upgrade the existing 44kV:8.32kV 5MVA transformer at Chesterville Frood DS to 10MVA to support load growth in the Chesterville area.	933	East	1.0	8.5	0.0	0.0	0.0
Russell HVDS Upgrade	SS-01.95	Upgrade the existing 115kV:8.32kV 6MVA transformer at Russell High Voltage DS to 12.5MVA and rebuild Russell DS F3 and F4 8.32kV feeders for approximately 4 kilometres to support load growth in the Town of Russell.	1,180	East	2.7	9.3	0.0	0.0	0.0
Marysville DS F4 Expansion	SS-01.96	Extend Marysville DS F4 8.32kV feeder by approximately 2.5 kilometers to support load growth in the Marysville area.	671	East	1.3	2.6	0.0	0.0	0.0
Brockville King St DS	SS-01.97	Build a new single-bank 44kV:8.32kV 10MVA DS with three feeder positions, and approximately 2 kilometers of 8.32kV line extension, to support load growth in the Brockville area.	706	East	1.1	2.6	7.0	0.0	0.0
Morrisburg TS M23 Regulator	SS-01.98	Install 44kV regulators on Morrisburg TS M23 44kV feeder to support load growth and voltage support in the Johnstown area.	1,092	East	0.6	1.5	0.0	0.0	0.0
Cobalt DS - Station Relocation	SS-01.99	Build new 44kV:12.5kV 3MVA Padmounted DS with three feeder positions and extend the Dymond TS M2 44kV feeder by approximately 3.5	1,260	North	1.8	0.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		kilometer to support load growth in the Cobalt area.							
Lebel PDS	SS-01.100	Build new 44kV:12.5kV 3MVA Padmounted DS with one feeder position to support load growth in the King Kirkland area.	281	North	0.0	0.5	1.9	0.0	0.0
White River DS Third Transformer Installation	SS-01.101	Build a third 115kV:25kV 7.5MVA transformer bank in White River DS, to support load growth in the White River area.	718	North	0.0	7.0	0.0	0.0	0.0
Kashabowie HVDS	SS-01.102	Build a new dual-bank 115kV:12.5kV 7.5MVA High Voltage DS with two feeder positions to support load growth in the Kashabowie area.	623	North	0.0	0.5	3.3	13.6	0.0
Lac Seul FN 1ph to 3ph Conversion	SS-01.103	Upgrade approximately 24 kilometers of Sam Lake DS F1 25kV feeder from single phase to three phase to support load growth in the Lac Seul First Nations community.	491	North	0.0	0.6	5.2	0.0	0.0
Chapleau DS #2 Upgrade - Load Growth	SS-01.104	Build a new single-bank 115kV:25kV 7.5MVA bank with two feeder positions at Chapleau DS#2 and approximately 1km of 25kV line extension to support load growth in the Chapleau area.	1,658	North	10.4	0.0	0.0	0.0	0.0
Devlin DS F1 Three-phase Conversion - Load growth	SS-01.105	Upgrade approximately 20 kilometers of Devlin DS F1 12.5kV feeder from single phase to three phase to support load	320	North	4.8	0.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		growth in the Naicatchewenin First Nations community.							
Crilly DS Replacement	SS-01.106	Build a new single-bank 230kV:25kV 7.5MVA DS with two feeder positions and 2km of 25kV line extension to support load growth in the Midhurst area.	480	North	0.0	0.5	3.3	6.6	10.2
Kenora DS F1 Three-phase Conversion - Load Growth	SS-01.107	Upgrade approximately 5 kilometers of Kenora DS F1 12.5kV feeder from single phase to three phase to support load growth in the Dalles First Nations community.	771	North	0.1	1.2	0.0	0.0	0.0
Kleinburg TS M6 Mayfield Rd Line Extension	SS-01.108	Extend Kleinburg TS M6 27.6kV feeder by 2km to support load growth in the Mayfield area.	1127	South	0.0	0.3	2.4	0.0	0.0
Tilsonburg-Norfolk Tie Line	SS-01.109	Extend Norfolk TS M1 27.6kV feeder by approximately 2 kilometers to support load growth in the Delhi area.	4,474	South	2.8	0.0	0.0	0.0	0.0
Macville - new 27.6kV station and feeders	SS-01.110	Build a new dual-bank 44kV:27.6kV 10MVA DS with two feeder positions and 3.5km of 27.6kV line extension to support load growth in the Macville area.	519	South	2.0	0.0	0.0	0.0	0.0
Elora Area Load Relief	SS-01.111	Upgrade the existing 44kV:8.32kV 5MVA transformer at Ponsonby DS to 7.5MVA and approximately 0.65 kilometer of 8.32kV line extension to support load growth in the Elora area.	6,746	South	4.9	0.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Grand Bend Express Feeder - Load Growth	SS-01.112	Build approximately 1.5 kilometers of new 27.6kV line to extend the F3 feeder from Grand Bend East DS to support load growth in the Grand Bend area.	4,576	South	0.2	1.6	0.0	0.0	0.0
Bondhead Area Load Growth	SS-01.113	Upgrade the existing 44kV:8.32kV 5MVA transformer at Bondhead DS to 10MVA to support load growth in the Bondhead community.	1,340	South	0.5	3.3	0.0	0.0	0.0
McGregor DS Replacement	SS-01.114	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at McGregor DS to 7.5MVA to support load growth in the McGregor community.	1,332	South	0.0	0.5	2.8	0.7	0.0
Alloa Load Growth	SS-01.115	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions to support load growth in the Alloa area.	1,559	South	4.9	1.8	0.0	0.0	0.0
Tillsonburg TS New DESN Feeder Build	SS-01.116	Build approximately 55 kilometers of 27.6kV line to extend two new feeders from Tilsonburg TS to support load growth in the greater Tilsonburg area.	18,839	South	0.6	17.1	17.5	17.8	0.0
Palmerston TS – M2 Load relief - New feeder	SS-01.117	Build approximately 8.4 kilometers of new 44kV line to extend the M5 feeder from Palmerston TS to support load growth in the Perth County and Wellington County areas.	3,081	South	1.2	10.7	0.0	0.0	0.0
Newport PDS Load Relief	SS-01.118	Voltage convert approximately 6 kilometers of Newport PDS F1 8.32kV feeder by extending the Caledonia TS M6 27.6kV	463	South	0.0	0.4	2.8	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		feeder to support load growth in the Six Nations area.							
Lambton TS M7/M2 Feeder Build	SS-01.119	Build approximately 15 kilometers of new 27.6kV line to extend the M2 and M7 feeders from Lambton TS to support load growth in the Lambton county area.	7,656	South	0.0	0.0	0.0	4.3	5.4
Leamington Area DESN5 Feeder Development	SS-01.120	Build approximately 11 kilometers of 27.6kV line to extend twelve new feeders from Leamington Area TS DESN6 to support load growth in the Kingsville and Leamington areas.	16,259	South	0.0	0.0	1.1	14.9	16.2
Leamington Area DESN6 Feeder Development	SS-01.121	Build approximately 15 kilometers of 27.6kV line to extend twelve new feeders from Leamington Area TS DESN6 to support load growth in the Kingsville and Leamington areas.	16,259	South	0.0	1.6	19.4	14.0	9.3
Greens Corners Transformer Replacement Load Growth	SS-01.122	Voltage convert approximately 11 kilometers of Greens Corners DS F2 8.32kV feeder by extending Norfolk TS M3 27.6kV feeder to support load growth in the Simcoe area.	435	South	0.0	0.7	6.7	0.0	0.0
St Williams DS New Feeder Position	SS-01.123	Build approximately 3 kilometers of 8.32kV line to extend one new feeder from the St. Williams DS to support load growth in the St. Williams area.	1,450	South	0.0	0.3	2.7	0.0	0.0
Aylmer West Conversion	SS-01.124	Extend Aylmer TS M2 27.6kV feeder by approximately 8 kilometers to support load growth in the east of Town of Aylmer.	394	South	0.0	0.5	4.5	0.0	0.0

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					2028	2029	2030	2031	2032
Youngsville DS Transformer Replacement-Load Growth	SS-01.125	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Youngsville DS to 7.5MVA to support load growth in the Youngsville area.	742	South	3.4	0.0	0.0	0.0	0.0
Shelburne 4th Line DS and feeders	SS-01.126	Build a new single-bank 44kV:8.32kV 10MVA DS with three feeder positions and 1km of 8.32kV line extension to support load growth in the Shelburne area.	2,531	South	1.0	0.0	0.0	0.0	0.0
Wardsville DS Upgrade	SS-01.127	Upgrade the existing 27.6kV:8.32kV 2MVA transformer at Wardsville DS to 5MVA to support load growth in the Wardsville community.	447	South	0.5	3.4	0.0	0.0	0.0
New DESN at Middleport TS Feeder Build	SS-01.128	Build approximately 45 kilometers of 27.6kV line to extend eight new feeders from the new Middleport TS to support load growth in the Hamilton and Ancaster areas.	45,880	South	8.1	36.8	37.5	0.0	0.0
Delhi Industrial DS Protection Upgrades	SS-01.129	Upgrade secondary protection equipment at Delhi Industrial DS to accommodate load growth in the Delhi area.	653	South	0.1	1.0	0.0	0.0	0.0
Mount Forest DS #2 Load Growth	SS-01.130	Upgrade the existing 44kV:8.32kV 5MVA transformer at Mount Forest DS #2 to 10MVA to support load growth in the Mount Forest area.	1,145	South	3.5	2.8	0.0	0.0	0.0
Dundalk Area Load Growth	SS-01.131	Build a new single-bank 44kV:8.32kV 10MVA DS with three feeder positions to support load growth in the Dundalk community.	2,041	South	1.5	6.0	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
New Yarmouth Center DESN Feeder Build	SS-01.132	Build approximately 28 kilometers of 27.6kV line to extend twelve new feeders from the new Yarmouth Centre TS to support load growth in the area surrounding St. Thomas.	5,445	South	0.0	2.2	10.2	10.2	0.0
Malden M12 Meloche Rd Extension	SS-01.133	Extend Malden TS M12 27.6kV feeder by approximately 1.2 kilometers to support load growth in the Amherstburg area.	3,580	South	0.0	0.1	1.1	0.0	0.0
Kent TS M1 Feeder Build	SS-01.134	Build approximately 7 kilometers of new 27.6kV line to extend the M1 feeder from Kent TS to support load growth in the Chatham-Kent area.	2,909	South	0.0	0.5	1.9	2.0	0.0
Kingsville M1 Offloading	SS-01.135	Extend Malden TS M11 27.6kV feeder by approximately 3 kilometers to support load growth in the Towns of Kingsville and Essex.	3,673	South	0.0	0.5	3.4	0.0	0.0
Bear Line Chatham Line Extension	SS-01.136	Extend Kent TS M24 27.6kV feeder by approximately 4 kilometers to support load growth in the Chatham-Kent area.	2,907	South	0.0	0.8	1.7	0.0	0.0
Dunnville TS M1 Load Relief	SS-01.137	Build two 27.6kV:8.32kV 2.5MVA Padmounted Distribution Stations with one feeder position, and extend Dunville TS M2 27.6kV feeder by approximately 6.5 kilometers, to support load growth in the Haldimand County area.	678	South	0.4	5.3	0.0	0.0	0.0
Norfolk TS M4 Extension	SS-01.138	Extend Norfolk TS M4 27.6kV feeder by approximately 10 kilometers to support load growth in the Norfolk area.	4,696	South	0.0	0.5	5.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Commerce Way TS New Feeder Build - Load Growth	SS-01.139	Build approximately 5 kilometers of 27.6kV line to extend two new feeders from the Commerce Way TS to support load growth in the City of Woodstock.	16,848	South	4.7	0.0	0.0	0.0	0.0
New Erin Sideroad 17 DS and Feeders - Load Growth	SS-01.140	Build a new single-bank 44kV:12.5kV 10MVA DS with three feeder positions to support load growth in the Town of Erin.	829	South	4.7	0.0	0.0	0.0	0.0
Commerce Way TS New Feeder Build #3 - Load Growth	SS-01.141	Build approximately 3 kilometers of 27.6kV line to extend one new feeder from the Commerce Way TS to support load growth in the City of Woodstock.	11,872	South	2.5	0.0	0.0	0.0	0.0
New Listowel South DS and Feeders	SS-01.142	Build a new single-bank 44kV:8.32kV 7.5MVA DS with three feeder positions to support load growth in the Town of Listowel area.	1,898	South	3.6	0.0	0.0	0.0	0.0
New Listowel North DS - Load Growth	SS-01.143	Build a new single-bank 44kV:8.32kV 7.5MVA DS with three feeder positions to support load growth in the Town of Listowel area.	901	South	1.6	5.4	0.0	0.0	0.0
New Listowel East PDS - Load Growth	SS-01.144	Build new 44kV:8.32kV 3MVA Padmounted DS with two feeder positions to support load growth in the Town of Listowel area.	207	South	0.0	0.5	2.2	0.0	0.0
Gourock DS F1 Load Growth Conversion	SS-01.145	Voltage convert approximately 6 kilometers of Gourock DS F1 8.32kV feeder by extending the Puslinch DS F1 27.6kV	674	South	0.0	0.3	2.4	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		feeder to support load growth in the Cambridge area.							
Puslinch DS Load Relief	SS-01.146	Build a new dual-bank 115kV:27.6kV 15MVA High Voltage DS with four feeder positions and approximately 2.8km of 27.6kV line extension to support load growth in the Puslinch area.	17,183	South	0.2	0.5	8.3	7.7	0.0
New Fergus DS	SS-01.147	Build a new single-bank 44kV:8.32kV 10MVA DS with four feeder positions and and approximately 2.2km of 8.32kV line extension to support load growth in the Elora area.	6,746	South	7.4	0.0	0.0	0.0	0.0
Schomberg DS T2 Fan Monitoring	SS-01.148	Install fan monitoring and SCADA telemetry at Schomberg DS to provide additional capacity to support load growth in the Schomberg area.	2,425	South	0.2	1.0	0.0	0.0	0.0
Cedar Mills DS Fan Monitoring	SS-01.149	Install fan monitoring and SCADA telemetry at Cedar Mills DS to provide additional capacity to support load growth in the Palgrave area.	4,148	South	0.2	1.0	0.0	0.0	0.0
Fergus TS M6 Extension Load Growth	SS-01.150	Extend Fergus TS M6 44kV feeder by approximately 8 kilometers to support load growth in the Town of Fergus area.	2,402	South	0.8	5.9	0.0	0.0	0.0
Ingersoll TS M50 Load Relief	SS-01.151	Extend Ingersoll TS M44 27.6kV feeder by approximately 3.5 kilometers to support load growth in the Ingersoll area.	601	South	1.2	0.0	0.0	0.0	0.0
Pelham Load Relief	SS-01.152	Build a new dual-bank 115kV:27.6kV 15MVA High Voltage DS with four feeder	12,178	South	4.5	5.7	27.6	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		positions and approximately 20km of 27.6kV line extension to support load growth in the Pelham area.							
Vanastra DS Express Feeder - Load Growth	SS-01.153	Build approximately 3 kilometers of new 8.32kV line to extend the F3 feeder from Vanastra DS to support load growth in the Town of Bayfield area.	1,945	South	0.0	0.1	1.0	0.0	0.0
Kleinburg TS M30 Feeder	SS-01.154	Build approximately 19 kilometers of new 44kV line to extend the M30 feeders from Kleinburg TS to support load growth in the Mayfield and Snelgrove areas.	2,015	South	0.0	1.2	5.8	5.6	0.0
Kleinburg TS M9 Feeder	SS-01.155	Build approximately 9 kilometers of new 27.6kV line to extend the M9 feeder from Kleinburg TS to support load growth in the Bolton area.	1,126	South	0.7	4.5	3.0	0.0	0.0
New Alliston DS and feeders	SS-01.156	Build a new dual-bank 44kV:27.6kV 10MVA DS with two feeder positions and approximately 2km of 27.6kV line extension to support load growth in the Alliston area.	748	South	0.0	0.0	0.6	1.7	10.1
Everett DS Load Growth	SS-01.157	Build a new single-bank 44kV:8.32kV 10MVA DS with three feeder positions to support load growth in the Everett community.	2,123	South	0.0	0.0	0.6	1.7	4.9
Six Nations 27.6kV Conversion	SS-01.158	Voltage convert approximately 17 kilometers of Lythmore DS F2 and F3, and sections of Caledonia TS M3 and Jarvis TS M3 feeders, from 8.32kV to 27.6kV to	1,067	South	3.8	3.9	0.0	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		support load growth in the Six Nations area.							
Wanstead TS Load Growth	SS-01.159	Build approximately 10 kilometers of new 27.6kV line to extend the M5 feeder from Wanstead TS to support load growth in the Lambton county area.	930	South	0.0	1.0	2.9	9.7	0.0
Haycroft DS Load Growth	SS-01.160	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Haycroft DS to 7.5MVA to support load growth in the Haycroft community.	1,219	South	0.5	4.6	0.0	0.0	0.0
Vittoria DS Load Relief	SS-01.161	Build new 27.6kV:8.32kV 2.5MVA Padmounted Distribution Station with two feeder positions, and extend Norfolk TS M3 27.6kV feeder by approximately 7 kilometers, to support load growth in the Turkey Point area.	1,905	South	0.0	0.8	7.4	0.0	0.0
Ingersoll TS M45 - Southern Load Relief	SS-01.162	Extend Buchanan TS M21 27.6kV feeder by approximately 5.3 kilometers to support load growth in the Crampton area.	2,183	South	4.8	0.0	0.0	0.0	0.0
Troy DS F2 Conversion	SS-01.163	Voltage convert approximately 2.5 kilometers of Troy DS F2 8.32kV feeder by extending the Dundas TS M8 27.6kV feeder to support load growth in the Town of Troy.	244	South	0.0	0.0	0.0	0.2	1.3
New Maple Grove HVDS	SS-01.164	Build a new dual-bank 115kV:27.6kV 15MVA High Voltage DS with four feeder positions and approximately 12.4km of	7,332	South	0.0	0.5	3.0	27.8	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
		27.6kV line extension to support load growth in the north London area.							
Caledonia Argyle DS Load Relief - Haldimand	SS-01.165	Upgrade the existing 27.6kV:8.32kV 3MVA transformer at Caledonia Argyle DS to 5MVA to support load growth in the Caledonia area.	706	South	2.3	0.0	0.0	0.0	0.0
Markdale North PDS Load Growth	SS-01.166	Build new 44kV:4.16kV 3MVA Padmounted DS with one feeder position and extend the Owen Sound TS M26 44kV feeder by approximately 0.5 kilometer to support load growth in the Markdale community.	655	South	0.0	0.5	1.9	0.0	0.0
Dover Centre DS Transformer Upgrade	SS-01.167	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Dover Centre DS to 7.5MVA to support load growth in the Dover Centre community.	1,431	South	0.0	0.5	3.0	0.5	0.0
Kent TS M17 Offload	SS-01.168	Extend Kent TS M1 27.6kV feeder by approximately 12 kilometers to support load growth in the Chatham-Kent area.	119	South	0.0	0.5	4.9	5.9	0.0
Rodney West DS Transformer Upgrade	SS-01.169	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Rodney West DS to 7.5MVA to support load growth in the Rodney community.	1,168	South	0.0	0.5	3.0	0.5	0.0
Thamesville North DS Transformer Upgrade	SS-01.170	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Thamesville DS to 7.5MVA to support load growth in the Thamesville community.	1,222	South	0.0	0.5	2.2	1.3	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Tilbury West DS F2 Feeder Extension	SS-01.171	Extend Tilbury West DS F2 27.6kV feeder by approximately 16 kilometers to support load growth in the Coatsworth area.	405	South	0.0	0.5	8.7	4.0	0.0
Bloomsburg M3 Load Relief	SS-01.172	Extend Jarvis TS M2 27.6kV feeder by approximately 10 kilometers to support load growth in the Port Dover area.	4,556	South	0.0	0.5	4.5	0.0	0.0
Keith TS New Feeder Build	SS-01.173	Build approximately 25 kilometers of new 27.6kV line to extend the M7 and M8 feeders from Keith TS to support load growth in the La Salle and Amherstburg area.	7,057	South	0.0	0.5	9.7	11.9	0.0
New Wildfield DS and Feeders	SS-01.174	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions and approximately 1km of 44kV line extension to support load growth in the Wildfield area.	1,126	South	5.3	1.2	0.0	0.0	0.0
Corbetton DS – 8.32kV Feeder Extension	SS-01.175	Extend Corbetton DS - F1 8.32kV feeder by approximately 2km to support load growth in the Dundalk community.	1,162	South	1.6	0.0	0.0	0.0	0.0
New DS & Feeders in Mount Wolfe area	SS-01.176	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions to support load growth in the Palgrave and Colgan area.	3,499	South	0.0	0.0	0.6	1.7	8.2
Lauzon TS DESN2 Egress Build	SS-01.177	Build approximately 16 kilometers of 27.6kV line to extend five new feeders from Lauzon TS to support load growth in the City of Windsor and the Town of Tecumseh.	7,309	South	0.0	1.1	9.7	0.0	0.0

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Stratford DS Transformer Replacement	SS-01.178	Voltage convert approximately 9 kilometers of Stratford DS F1 and F2 8.32kV feeders by extending the Stratford TS M1 and M6 27.6kV feeders to support load growth in the Stratford area.	723	South	0.6	5.1	0.0	0.0	0.0
Stratford East Hope Transformer Replacement	SS-01.179	Upgrade the existing 27.6kV:8.32kV 3MVA transformer at Stratford East Hope DS to 5MVA to support load growth in the Stratford area.	379	South	1.1	0.0	0.0	0.0	0.0
Harriston DS #2 Transformer Upgrade	SS-01.180	Upgrade the existing 44kV:8.32kV 5MVA transformer at Harriston DS#2 to 10MVA to support load growth in the Harriston area.	919	South	5.6	0.0	0.0	0.0	0.0
New Bolton North Hill DS and Feeders	SS-01.181	Build a new single-bank 44kV:27.6kV 10MVA DS with two feeder positions and approximately 2km of 27.6kV line extension to support load growth in the Bolton North Hill area.	1,074	South	0.0	0.0	0.6	0.9	10.0
Jarvis TS M3 Reconductoring	SS-01.182	Reconductor 16 kilometers of 27.6kV line on the Jarvis TS M3 feeder to support load growth in the Six Nations area.	1,742	South	0.4	6.1	2.1	0.0	0.0
Merlin DS Transformer Upgrade	SS-01.183	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Merlin DS to 7.5MVA to support load growth in the Merlin community.	958	South	0.5	3.3	0.0	0.0	0.0
Bickford Load Growth	SS-01.184	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Bickford DS to 7.5MVA to support load growth in the Bickford area.	1,574	South	0.0	0.0	0.0	0.6	3.7

Project Name	Project ID	Project Description	Count of Existing Customers that would benefit	Region	Net Capital Investment ($M)				
					2028	2029	2030	2031	2032
Fergus TS M4 M8 Load Relief	SS-01.185	Regulators on M8 and M4 to support load growth in the greater Fergus area	3,419	South	0.0	0.0	0.0	0.2	1.8
Coatsworth DESN1 Feeder Development	SS-01.186	Build approximately 12 kilometers of 27.6kV line to extend twelve new feeders from Coatsworth TS to support load growth in the Coatsworth area.	1,027	South	0.0	0.0	1.1	7.9	17.2
Coatsworth DESN2 Feeder Development	SS-01.187	Build approximately 7 kilometers of 27.6kV line to extend twelve new feeders from Coatsworth TS to support load growth in the City of Windsor and the Town of Tecumseh.	1,027	South	0.0	0.0	1.1	5.6	8.0
Carlisle DS Relocation Load Relief	SS-01.188	Build a new single-bank 27.6kV:8.32kV 10MVA DS with three feeder positions to support load growth in the Carlisle area.	1,533	South	1.9	4.9	0.0	0.0	0.0
New DESN at Nebo TS Feeder Build	SS-01.189	Build approximately 20 kilometers of 27.6kV line to extend six new feeders from the Nebo TS to support load growth in the Hamilton area.	45,880	South	0.0	0.0	2.9	13.5	13.7
Secondary System Electrification	SS-01.190	Upgrade secondary side service transformers forecasted to be overloaded due to Electric Vehicle penetration.	N/A	Various	7.8	8.0	8.1	9.0	9.2
Other Projects (<$1M)				Various	5.0	4.3	4.3	0.7	0.3
Total					**250.2**	**282.9**	**357.7**	**259.7**	**227.0**

APPENDIX B - DESCRIPTION OF INVESTMENTS - ORILLIA RZ

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2028	2029	2030	2031	2032
Other Projects (<$1M)			0.20	0.13	0.00	Embedded in Hydro One Networks	
Total			**0.20**	**0.13**	**0.00**		

APPENDIX C - DESCRIPTION OF INVESTMENTS - PETERBOROUGH RZ

Project Name	Project ID	Project Description	Net Capital Investment ($ Millions)				
			2028	2029	2030	2031	2032
Other Projects (<$1M)			0.00	0.00	0.00	Embedded in Hydro One Networks	
Total			**0.00**	**0.00**	**0.00**		

APPENDIX D - NWS PROJECTS

Project Name	Project ID	Project Description	Region	Gross Capital Investment ($ Millions)[4]				
				2028	2029	2030	2031	2032
Birr DS Load Growth	NWS.01	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Birr DS to 7.5MVA to support load growth in the Ilderton area	South	0.0	0.5	5.2	0.0	0.0
Carleton Place Francis DS Load Growth	NWS.02	Upgrade the existing 44kV:4.16kV 5MVA transformer at Carleton Place Francis DS to 10MVA to support load growth in the town of Carleton Place	East	0.0	0.0	0.8	7.0	0.1
Chesterville M1 Load Growth	NWS.03	Extend a new Chesterville TS M4 44kV feeder for 11km to reduce loading on the M1 feeder and support growth in the Winchester area	East	0.0	0.4	4.0	9.0	0.0
New Bragg DS and feeders	NWS.04	Build a new single-bank 44kV:27.6kV, 10MVA DS with two feeder positions, to support continued growth in the Clarington area	Central	0.0	0.5	1.7	5.6	0.0
Fergusonvale DS Transformer Upgrade	NWS.05	Upgrade the existing 44kV:8.32kV 5MVA transformer at Fergusonvale DS to 10MVA to support load growth in Springwater township	Central	0.0	0.5	3.9	0.0	0.0
Dixons Corners DS	NWS.06	Upgrade the existing 44kV:8.32kV 5MVA transformer at Dixons Corners DS to 10MVA to support load growth in the Winchester area	East	0.0	0.3	2.2	2.0	0.0

[4] Figures presented in the tables may not sum to the totals shown due to rounding.

Horsey Bay DS T2 Load Growth	NWS.07	Upgrade the existing 44kV:8.32kV 5MVA T2 transformer at Horsey Bay DS to 10MVA to support load growth in the Kingston area	Central	0.0	0.5	1.1	0.6	0.0
Kingsville Pulford DS Load Growth	NWS.08	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Kingsville Pulford DS to 7.5MVA to support load growth in the Kingsville area	South	0.0	0.5	4.7	0.0	0.0
Lanark DS Load Growth	NWS.09	Upgrade the existing 44kV:8.32kV 5MVA transformer at Lanark DS to 10MVA, and add a new F4 feeder, to support load growth in the Lanark area	East	0.0	0.8	6.8	0.1	0.0
Smithfield DS Load Growth	NWS.10	Upgrade the existing 44kV:8.32kV 5MVA transformer at Smithfield DS to 7.5MVA to support load growth in the Trenton area	Central	0.0	0.5	3.9	0.0	0.0
Southwold DS Load Growth	NWS.11	Upgrade the existing 27.6kV:8.32kV 2.8MVA transformer at Southwold DS to 5MVA to support load growth in the area west of St. Thomas	South	0.0	0.6	3.0	1.8	0.0
Violet Hill DS Load Growth	NWS.12	Upgrade the existing 44kV:8.32kV 5MVA transformer at Violet Hill DS to 7.5MVA to support load growth in the area east of Shelburne	Central	0.0	0.5	3.9	0.0	0.0
Warwick DS Load Growth	NWS.13	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at Warwick DS to 7.5MVA to support load growth in the Watford area.	South	0.0	0.5	5.6	0.0	0.0
West Lorne DS Load Growth	NWS.14	Upgrade the existing 27.6kV:8.32kV 5MVA transformer at West Lorne DS to 7.5MVA to support load growth in the West Lorne area.	South	0.0	0.5	5.2	0.0	0.0

Whitefish DS Upgrade – Load Growth	NWS.15	Upgrade the existing 44kV:12.5kV 6MVA transformer at Whitefish DS to 7.5/10/12.5MVA to support load growth in the area west of Sudbury.	North	0.0	0.5	3.3	9.6	0.0
Woodland Beach DS Transformer Upgrade	NWS.16	Upgrade the existing 44kV:8.32kV 5MVA transformer at Woodland Beach DS to 10MVA to support load growth north of Wasaga Beach	Central	0.0	0.5	3.9	0.0	0.0
TOTAL				**0.0**	**8.0**	**59.0**	**35.6**	**0.1**

D-SS-02	RELIABILITY IMPROVEMENTS
Primary Trigger:	Reliability
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	10.8	18.6	27.1	24.5	3.6	84.5
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This investment is for the construction of new feeder ties, enhancement of existing feeder ties to increase load transfer capability, and the reduction of feeder exposure by splitting existing feeder load into two or more feeders. The Reliability Improvements investment mitigates the impact of outages and is expected to improve reliability and increase operational flexibility on the targeted feeders.

There are no planned capital expenditures for Orillia RZ or Peterborough RZ.

1.0 INVESTMENT NEED

Hydro One's distribution system is typically planned based on a radial supply. A radial design relies on a single supply source with no alternate source of power in the event of an outage. As a result, when there is an outage on a radial feeder the issue must be located and remedied before power can be restored to the impacted customers on that feeder, or portion of the feeder. These reliability impacts can be mitigated through creating new feeder ties, enhancing existing feeder ties to increase load transfer capability, or reducing feeder exposure by splitting existing feeder load into two or more feeders.

Customer engagement results identified decreasing outages and improving restoration time among top priorities; over 70% of customers support investments to improve overall system reliability (see SPF Section 1.6, Attachment 1, p. 550-552). This investment will improve feeder performance and reliability for customers served from 22 feeders.

The preferred reliability improvement approach for each feeder is selected based on the technically feasible option(s) and reliability analyses. For radial feeders that currently do not tie to another feeder, feeder ties can be constructed to establish transfer capabilities. Where a feeder tie is not feasible, investment can be made to reduce feeder exposure (i.e., reducing the number of customers reliant on a single feeder) by splitting existing feeder load into two or more feeders. For feeders with existing ties but without meaningful load transfer capability, system upgrades are performed to increase the capacity of load that can be transferred via the existing feeder tie, allowing more customers to be supplied from an alternate source when there is an outage on the primary supply.

This investment will reduce the impact of outages for customers supplied from the impacted feeders.

2.0 INVESTMENT DESCRIPTION

This investment is focused on improving reliability of 22 feeders through three different mitigation methods: 1. Creating new feeder ties by building new lines; 2. Enhancing existing feeder ties and enabling additional load transfer capability by performing system upgrades; and 3. Reducing feeder exposure by building new infrastructure to split up existing long feeders.

Candidate feeders are determined based on their historical contribution to system SAIDI, the number of customers served and the geographic configuration of the feeder which influences the feasible mitigation options. Each feeder is assessed to determine the appropriate reliability improvement solution. Appendix A lists the reliability improvement projects included under this investment, along with a description of their scope.

For feeders that are radial without any existing ties to another feeder, an alternate source of supply is considered. Construction of a new feeder tie enables an alternate source of supply. A new feeder tie point is evaluated based on its proximity to another feeder and the historical reliability performance of both feeders. If the feeder can be reasonably extended to meet another feeder, a new feeder tie point can be established between them. This new feeder tie would allow loads on one feeder to be transferred to the other feeder when the normal supply feeder experiences an outage. The ability to load transfer can reduce the frequency and duration of outages experienced by customers on the faulted feeder.

For feeders that have an established feeder tie, transfer capability can be limited by equipment rating and power quality on the receiving feeder. Enhancements such as increasing conductor size and the addition or upgrade of voltage regulators on the feeders can increase load transfer capability between the feeders. The increased load transfer capability allows the feeder tie to benefit additional customers. As a result, more customers benefit from reduced outage impact if their normal supply feeder experiences an outage.

For long feeders with extended exposure, reduction of feeder exposure is considered. This can be achieved by building new infrastructure with the purpose of splitting the long feeder into two or more feeders. When a long feeder is split into multiple shorter feeders, the impact of an outage is reduced due to the reduced number of customers on the faulted feeder.

2.1 INVESTMENT EXAMPLES

2.1.1 CREATING NEW FEEDER TIE - "MIDHURST TS M4-M9 TIE"

The Midhurst Transformer Station (TS) M4 and M9 feeders are both radial feeders that supply multiple distribution stations (DS) with over 9,000 residential and small commercial customers. Both feeders are approximately 40 km in length. Based on historical data, both Midhurst TS M4 and M9 feeders were among the feeders that contributed most to system SAIDI.

The proposed reliability improvement investment involves a 7 km line expansion on the Midhurst TS M4 feeder and an additional remote operable switch, to establish a tie with the Midhurst TS M9 feeder. This feeder tie will enable an alternate supply for over 5,000 residential and small commercial customers. This reduces power restoration time for those customers when a fault interrupts one of the feeders.

Figure 1 shows the current feeder configuration for the Midhurst TS M4 and Midhurst TS M9. With a radial design, any faults on either feeder will cause an interruption to the distribution stations supplied by the faulted feeder.

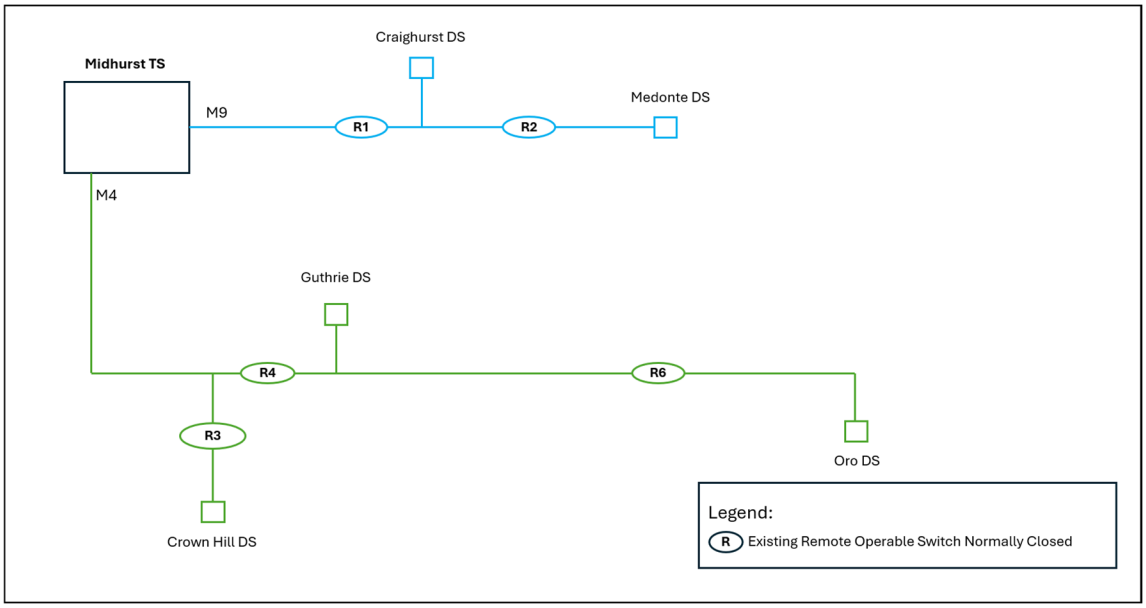


Figure 1: Current feeder configuration before investment

Figure 2 shows the feeder configuration after the addition of a 7 km tie line between the endpoints of Midhurst TS M4 and Midhurst TS M9 feeders. This configuration creates an alternate source of supply for both feeders and provides the flexibility to supply some impacted distribution stations from either Midhurst TS M4 or M9. When an interruption occurs on M9, Craighurst DS and Medonte DS can be restored through supply from M4, depending on the fault location. Similarly, when an interruption occurs on M4, the supply to Oro DS and Guthrie DS can be restored by M9.

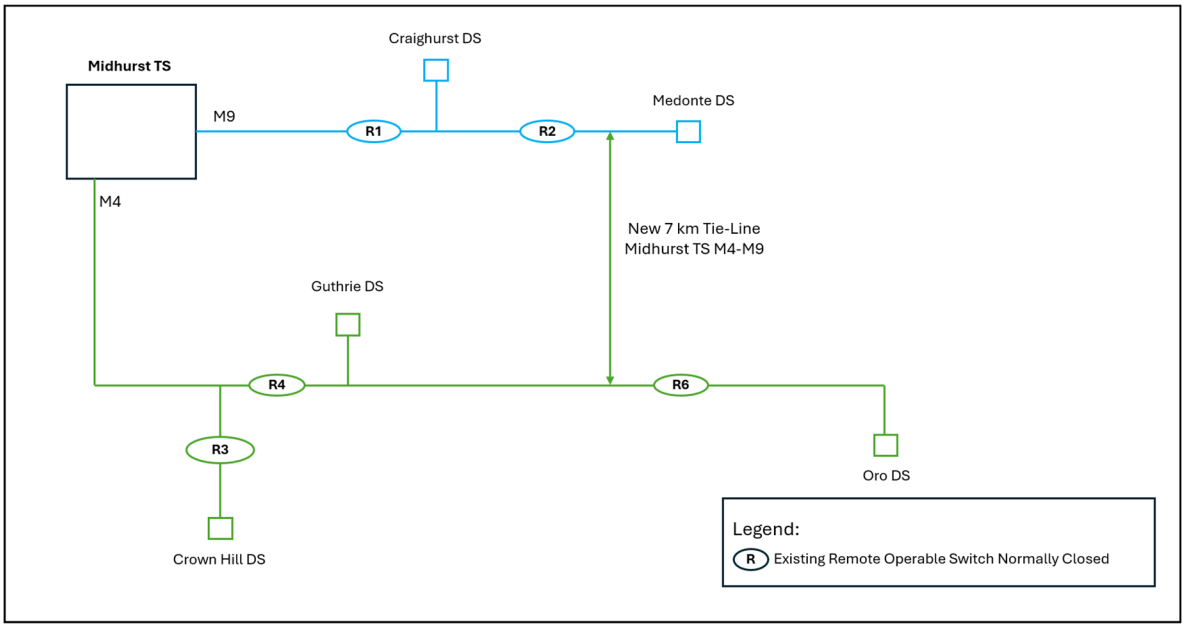


Figure 2: Normal Feeder Configuration After 7 km Tie Line Investment

2.1.2 ENHANCING EXISTING FEEDER TIE - "MUSKOKA TS M7 – RECONDUCTOR ON ECCLESTONE DRIVE"

The Muskoka TS M7 has an existing feeder tie with Bracebridge TS M21. Near the existing tie point, there is a 2.4 km section of mixed 1/0 and 3/0 ACSR conductor, which limits the amount of load that can be transferred via the existing tie point. Based on historical data, both Muskoka TS M7 and Bracebridge TS M21 feeders were among the feeders that contributed most to system SAIDI.

This proposed reliability improvement investment involves upgrading the 2.4 km of mixed 1/0 and 3/0 ACSR conductor to 556 AL conductor. This investment will increase the ampacity rating of Muskoka TS M7 at the tie point, improving the load transfer capability between Bracebridge TS M21 and Muskoka TS M7.

Figure 3 shows the location of the conductor section with limited ampacity. By upgrading that section of conductor, the existing tie point can be utilized at a greater capacity, enhancing the operational flexibility between Muskoka TS M7 and Bracebridge TS M21.

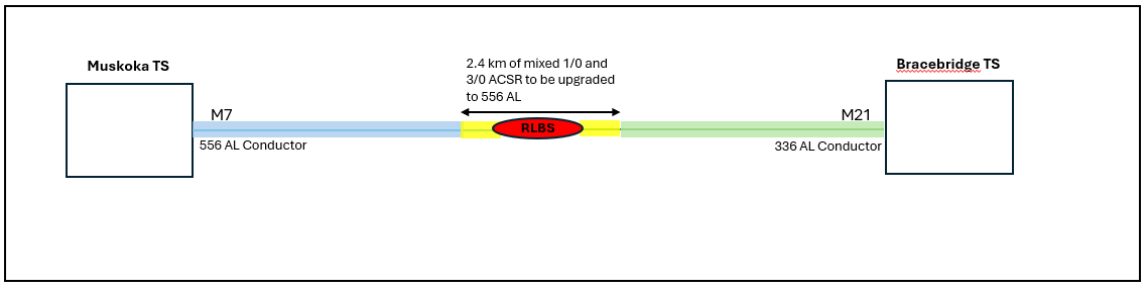


Figure 3: Feeder Configuration with the Proposed 2.4 km Feeder Upgrade

2.1.3 REDUCING FEEDER EXPOSURE - "WENDOVER F3 RELIABILITY"

Wendover DS F3 feeder covers over 100 km of distance overall, serving 2,500 residential, commercial, and DER customers. Due to its extended coverage, any fault on the feeder could impact many customers. Based on historical data, Wendover DS F3 was among the feeders that contributed most to system SAIDI.

This proposed reliability improvement investment involves installing a new feeder position for Wendover DS F2 within Wendover DS. Customers to the north of Wendover DS will be transferred to the new F2 feeder. Customers south of Wendover DS will continue to be supplied by the existing F3 feeder. This would enable 30% of the existing F3 feeder to be transferred and supplied from the new Wendover DS F2. By splitting the feeder into two feeders, the exposure of each feeder would be reduced, limiting the customer impact of a fault on either feeder.

Figure 4 shows the current feeder configuration of Wendover DS F3. The North and South branch of the feeder are both radially supplied from a single supply point Wendover DS F3.

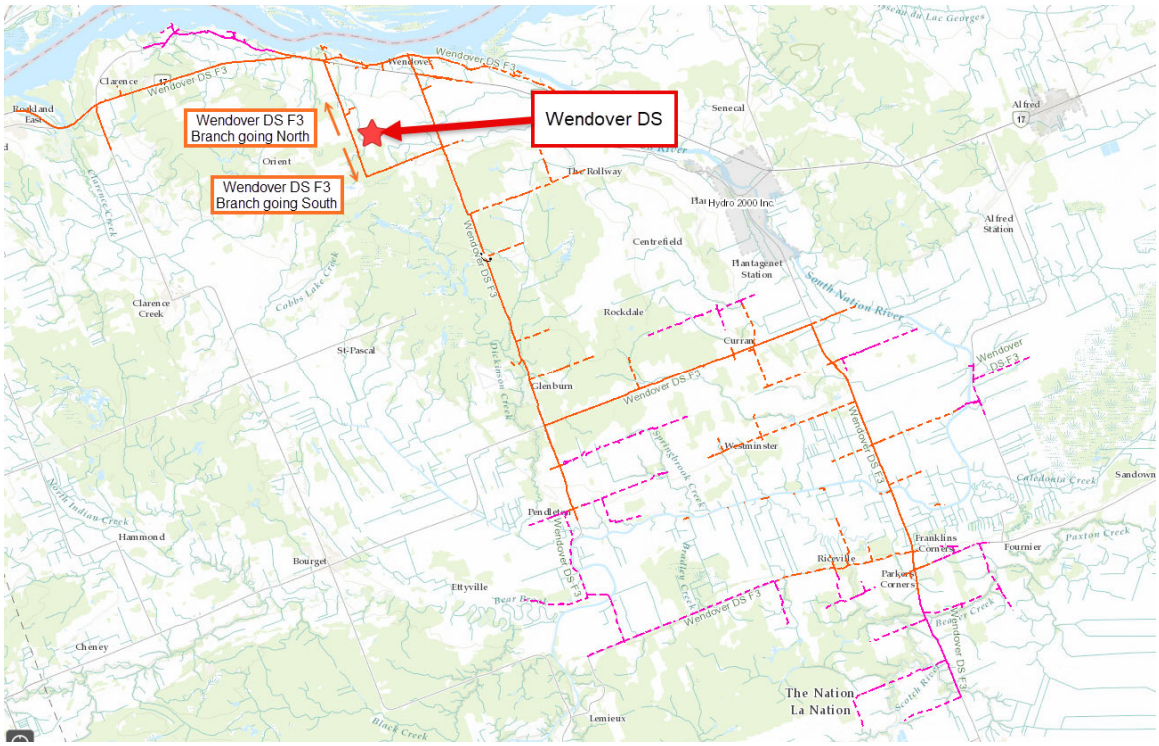


Figure 4: Current configuration of Wendover DS F3

Figure 5 shows the feeder configuration after the feeder has been split into Wendover DS F2 and Wendover DS F3. As a result, overall feeder exposure is split into two feeders and Wendover DS F3 will reduce its feeder exposure by 30% as the new Wendover DS F2 will pick up 30% of the current Wendover DS F3 feeder length.

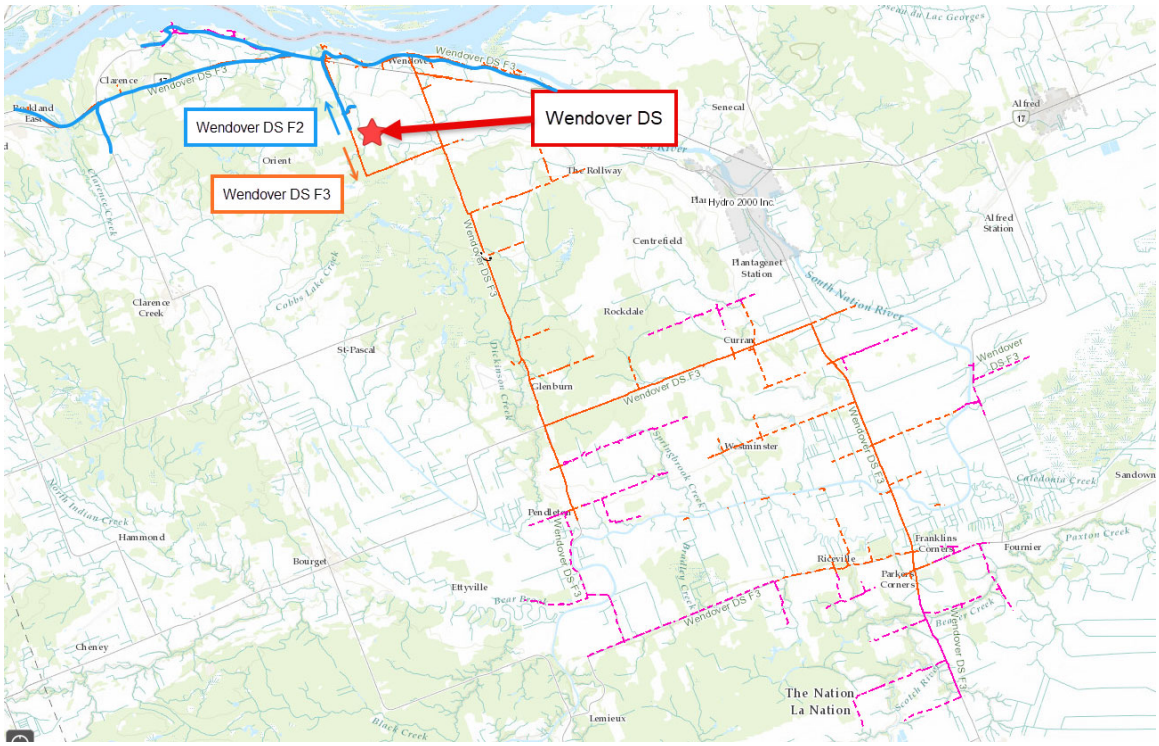


Figure 5: Feeder Configuration of Wendover DS F2 and Wendover DS F3 After a New Feeder Position is Constructed within Wendover DS

3.0 OUTCOMES

Reliability Improvement projects will:

- Improve operational efficiencies by restoring power to as many customers as possible via new feeder ties;
- Improve load transfer capability between feeders to reduce impact of power interruption events via enhanced existing feeder tie capability; and
- Reduce the frequency of interruptions by reducing feeder exposure.

3.1 OEB RRF OUTCOMES

Table 1 below presents the 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 • Reduced customer impact in power interruption events
Operational Effectiveness	• Increased operational flexibility and load transfer capability between feeders in reasonable proximity of each other • Reduced outage duration and/or frequency and improved reliability

4.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 planning period. There are no planned projects for Orillia RZ and Peterborough RZ. A detailed breakdown of all expenditures under this investment can be found in Appendix A.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	43.9	18.5	10.8	20.8	30.4	27.3	4.6	93.8
Less Removals	5.4	2.1	0.0	2.2	3.3	2.8	1.0	9.3
Less Capital Contributions	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**38.5**	**15.7**	**10.8**	**18.6**	**27.1**	**24.5**	**3.6**	**84.5**

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be $22.8M lower than planned. The variance reflects lower expenditures driven primarily by the reprioritization of funding in response to non-discretionary emerging system needs. As a result, three material investments are proceeding in the 2023-2027 rate period compared to six material investments that were planned.

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

2028-2032 EXPENDITURES

Hydro One forecasts expenditures for this investment to be $84.5M over the 2028-2032 planning period.

The factors influencing the cost of the investment include:

- the extent of new line construction and/or forestry work required for the new feeder section;
- the setbacks required by the road authority or property owner for the new feeder section;
- asset additions or upgrades needed to accommodate the system upgrades for the new alternate supply, such as a larger conductor, a new transformer or regulator;
- escalation on the cost of key distribution system components required to complete investment scopes; and
- unforeseen property/easement issues.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: DO NOTHING

Under this alternative, Hydro One would not proceed with the proposed reliability investments. This alternative was rejected because it would not result in reliability improvements and is not aligned with customer priorities.

ALTERNATIVE 2: NON-WIRES SOLUTIONS

From a technical standpoint, reliability needs on radial feeders could potentially be addressed through energy storage by islanding the feeders to enable back feed from an alternate source. However, for feeders serving many customers, providing sufficient energy storage capacity to replace the unsupplied energy during an outage would not be cost effective. The 22 feeders planned for remediation under this investment all have high contributions to SAIDI, serve many customers, and are geographically located within reasonable distance of other feeders. The wires investment is less complex, has a longer service life, and is not subject to the energy capacity limitations associated with storage

solutions. Accordingly, this alternative was rejected as a NWS could not reasonably and cost-effectively address the need.

ALTERNATIVE 3: TARGETED RELIABILITY IMPROVEMENTS (RECOMMENDED)

Under this alternative, Hydro One would implement targeted projects to improve reliability on selected feeders through the construction of feeder ties, enhancement of existing feeder ties, and reduction of feeder exposure. Feeders are selected based on criteria that ensure expenditures will result in material reliability improvements. This recommended alternative results in the execution of cost-effective opportunities to improve reliability and operational flexibility and is aligned with stated customer priorities.

6.0 EXECUTION RISK AND MITIGATION

The main risks concerning project execution are emergent issues identified during the detailed design stage. Table 3 provides the main execution risks and their associated mitigation strategy:

Table 3 - Risks and Mitigations

Execution Risk	Risk Mitigation
Need for additional property and easement to facilitate new line build and associated new equipment	Hydro One Real Estate to conduct early engagement with landholders and rights holders
Environmental concerns with new line build and associated new equipment	Managed through standard environmental studies and forestry clearing procedures
Outage availability for upgrades to enhance feeder ties scopes	Managed through extensive 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.

APPENDIX A - DESCRIPTION OF INVESTMENTS[4]

Project Name	Project ID	Project Description	Net Capital Investment ($M)				
			2028	2029	2030	2031	2032
Armitage TS M12 Conductor Upgrade	SS 02.1	Enhance existing feeder tie and load transfer capability by reconductoring 3 km of overhead line on Armitage TS M12. This project will enable load transfer of two additional DS serving over 2,000 customers between Armitage TS M12 and M32.	0.0	0.3	2.3	0.0	0.0
Aylmer Area Voltage Conversion	SS 02.2	Create new feeder tie by building 10 km of new line with 7 km of voltage conversion between Aylmer TS M2 and Tillsonburg TS M4 to enable load transfer capability.	0.0	0.3	0.5	5.3	0.0
Dokis FN Reliability Improvement	SS 02.3	Create new feeder tie by negotiating joint use of customer-owned line to enable alternate source of supply from Trout Lake TS M7 during an outage on Noelville DS F1, using a 44:12.47 kV PDS.	0.6	1.7	2.6	0.0	0.0
Gilmour DS New HVDS	SS 02.4	Reduce feeder exposure for over 2,000 customers radially supplied from Coe Hill DS F2 by building a new HVDS with two new feeders to divide existing Coe Hill DS F2 into three different supply feeders.	9.9	9.0	0.0	0.0	0.0
Midhurst TS M4-M9 44 kV Tie-line	SS 02.5	Create new feeder tie by building 8 km of new line between Midhurst TS M4 and M9 to enable load transfer capability.	0.0	0.7	5.2	1.0	0.0

[4] Figures presented in the tables may not sum to the totals shown due to rounding.

Project Name	Project ID	Project Description	Net Capital Investment ($M)				
			2028	2029	2030	2031	2032
Muskoka TS M2 M10 New Tie	SS 02.6	Create new feeder tie by building 2.8 km of new line between Muskoka TS M2 and M10 to enable load transfer capability.	0.0	0.5	2.1	0.0	0.0
Muskoka TS M3 M7 New Tie	SS 02.7	Create new feeder tie by building 4.1 km of new line between Muskoka TS M3 and M7 to enable load transfer capability.	0.1	1.0	2.9	0.0	0.0
Muskoka TS M7-Reconductor on Ecclestone Drive	SS 02.8	Enhance existing feeder tie and load transfer capability by reconductoring 2.4 km of overhead line at the existing tie point between Muskoka TS M7 and Bracebridge TS M21. With other feeder ties already existing in the area, this project will improve the operational flexibility in the area by increasing the load transfer capability between Bracebridge TS M21 and Muskoka TS M7.	0.1	1.7	0.0	0.0	0.0
Orillia TS M7-Midhurst TS M4 New Tie	SS 02.9	Create new feeder tie by building 8 km of new line between Orillia TS M7 and Midhurst TS M4 to enable load transfer capability.	0.0	0.7	2.6	4.0	0.0
St. Lawrence M25 x St. Isidore M5 Tie Line	SS 02.10	Create new feeder tie by building 13.2 km of new line between St. Lawrence TS M25 and St. Isidore TS M5 to enable load transfer capability.	0.0	1.3	5.1	6.9	0.0
Stayner TS M2 Tie Line	SS 02.11	Create new feeder tie by building 7 km of new line between Everett TS M5 and Stayner TS M2 to enable load transfer capability.	0.0	0.6	2.7	2.7	0.0

Project Name	Project ID	Project Description	Net Capital Investment ($M)				
			2028	2029	2030	2031	2032
Wendover F3 reliability	SS 02.12	Reduce feeder exposure of existing Wendover DS F3 by adding new feeder Wendover DS F2 to divide existing Wendover DS F3 into two different supply feeders.	0.1	0.9	0.0	0.0	0.0
Wilson TS M14 44kV Feeder Regulation	SS 02.13	Enhance existing feeder tie and load transfer capability by installing voltage regulator on Wilson TS M14. This project will address voltage drop concerns that currently limit load transfer capability between Wilson TS M14 and Enfield TS M4. With voltage regulation, additional load can be transferred between Wilson TS M14 and Enfield TS M4.	0.0	0.0	1.1	4.5	3.6

D-SS-03	DEMAND SYSTEM MODIFICATIONS
Primary Trigger:	Capacity
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	22.2	22.7	23.1	24.2	24.7	117.0
Orillia RZ	0.17	0.18	0.18	Embedded in Hydro One Networks		
Peterborough RZ	0.20	0.20	0.21			

Summary:

This non-discretionary investment addresses near-term system needs that arise because of localized growth on the distribution system and cause equipment overload or power quality issues. The primary trigger of this investment is capacity. Demand-driven system modifications are investments that enable localized load growth by promptly addressing capacity limitations.

1.0 INVESTMENT NEED

Demand system modifications are non-discretionary investments addressing near-term system needs that arise from naturally occurring changes to the distribution system. Naturally occurring system changes are usually caused by localized load growth. Load growth can cause a variety of issues such as equipment thermal overloads, protection limitations, power quality violations, and system inefficiencies. Under Ssection 3.3 (Enhancements) of the Distribution System Code (DSC), Hydro One is required to continue to plan and build its distribution system to mitigate such issues and accommodate reasonable forecast load growth.

2.0 INVESTMENT DESCRIPTION

Demand system modifications are minor investments driven by immediate or near-term needs. This investment includes the following types of demand work:

1. Immediate investments are primarily in response to urgent issues, such as power quality complaints typically driven by voltage excursions with respect to CSA CAN-C235-19. These investments are required to be implemented on an expedited basis.
2. Near-term localized growth investments are emergent and are executed to accommodate stringent customer timelines and localized growth. Demand System Modification investments are identified through known customer connection forecasts and regular power system analyses using tools such as CYME Power Engineering Software. CYME and other tools assess loading, voltage performance, feeder balance, protection limits, and line-end conditions to anticipate and address emerging system constraints associated with incremental customer load additions that may give rise to concerns in constrained areas of the Hydro One network. As these impacts are primarily attributable to underlying system limitations rather than material customer-driven load increases, the associated investments are not assigned to individual customers. These investments are required to align with and be completed in accordance with customer connection timeline requirements.

Projects executed under this investment are typically of the following nature:

- Addressing phase imbalance

- Addressing overloaded equipment
- Addressing protection deficiencies
- Addressing power quality issues

Demand system modifications address changes or upgrades on the primary side of the distribution system 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.

Upon identification of a system issue, Hydro One performs an evaluation to outline the feasible mitigating options. Technical criteria such as voltage delivery standards are used to assess power quality issues, and equipment thermal limits are used to assess capacity issues.

Demand System Modification investments typically 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. These modifications are undertaken on an urgent basis to address immediate and near-term system requirements. Accordingly, projects under this program are generally executed within compressed timelines, typically ranging from a few months to approximately one year. Projects executed under this program are also subject to a defined maximum capital cost threshold, ensuring that only appropriately sized, small-scale demand investments are included within this category.

3.0 OUTCOMES

The primary outcome of the investment 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-C235-19).

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits from the investment in accordance with the Ontario Energy Board's Renewed Regulatory Framework:

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.

4.0 EXPENDITURE PLAN

Tables 2, 3, and 4 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the prior rate period and forecast net capital expenditures for the planning period.

Table 2 - Hydro One – Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	81.1	132.0	25.3	25.8	26.3	27.5	28.1	132.9
Less Removals	9.2	13.3	3.0	3.1	3.2	3.3	3.4	16.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**71.9**	**118.6**	**22.2**	**22.7**	**23.1**	**24.2**	**24.7**	**117.0**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act" refers to Actual (2023-25) and "Fcst" refers to Forecast (2026-27) expenditures.

Table 3 - Orillia RZ – Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	N/A	0.96	0.21	0.22	0.22	Embedded in Hydro One Networks		
Less Removals		0.14	0.04	0.04	0.04			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.82**	**0.17**	**0.18**	**0.18**			

Table 4 - Peterborough RZ – Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	N/A	0.70	0.24	0.25	0.25	Embedded in Hydro One Networks		
Less Removals		0.10	0.04	0.04	0.05			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.60**	**0.20**	**0.20**	**0.21**			

The factors influencing the cost of Demand System Modifications are driven by the capability of Hydro One's existing assets to support localized growth, as well as the complexity, volume and scope of the remediation required to address identified system limitations.

2023-2027 EXPENDITURES

Over the 2023-2027 period, Hydro One forecasts net capital expenditures for this investment of $118.6M, compared to planned expenditures of $71.9M. Actual/forecast expenditures from 2023-2027 exceeded the plan, due to a significant increase in project volumes driven by localized load growth and an elevated number of customer-driven requests. Specifically, the program experienced a substantial increase in the number of demand-driven system modification projects in 2023, 2024, and 2025. Additionally, overall program expenditures have been further impacted by material cost escalation, with notable increases in key equipment costs such as voltage regulators and reclosers, consistent with increases outlined in SPF Section 1.8 for distribution equipment.

Witness: Peter Faltaous

2028-2032 EXPENDITURES

Over the planning period, forecast net capital expenditures are $117.0M. The factors influencing the cost of Demand System Modifications include the capability of Hydro One's existing assets to support localized growth, as well as the complexity, volume and scope of the remediation required to address identified system limitations. The level of investment is forecasted to increase compared to the 2023 – 2027 plan because of sustained growing volume of localized load growth driving a higher volume of work, and increased material costs. Forecast expenditures for this program are informed by historical cost trends, which indicate a sustained increase in demand system modification projects. Projected spending for the 2028-2032 period is aligned with actual/forecast demand system modification expenditures for the 2023-2027 period.

5.0 ALTERNATIVES

No alternatives are considered because failure to respond to immediate and near-term demand system needs that arise because of localized growth would violate the DSC and may result in unacceptable system performance.

6.0 EXECUTION RISK AND MITIGATION

Increased material costs and a higher volume of projects are identified as execution risks for this investment.

Costs for critical materials necessary to execute demand system modifications including, for example, cables, reclosers and voltage regulators, are subject to escalation. Cost escalation is caused by several factors including supply-chain disruptions, constrained manufacturing capacity, rising commodity prices, tariffs, increased demand for distribution grid equipment and inflation. These cost conditions reflect broader utility-sector market conditions (see SPF Section 1.8, subsection 1.8.3 for more information). Material cost pressure is mitigated through Hydro One's disciplined procurement practices including the use of multi-year contracts, indexed pricing, and multi-supplier strategies to provide sourcing resilience and flexibility, and to minimize pricing volatility and supply disruptions.

Project volume may differ from forecasts because of the demand-driven and non-discretionary nature of this investment. Therefore, overall project volumes are not within

the company's control. However, Hydro One will actively manage the associated execution impacts, particularly increased labour requirements, by maintaining operational flexibility and leveraging scalable resourcing strategies as discussed in Exhibit E-06-02 Workforce Planning.

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D-SS-04	ENERGY STORAGE SOLUTIONS
Primary Trigger:	Reliability
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	56.9	84.0	198.8	204.1	147.4	691.3
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This investment entails the deployment of battery energy storage systems (BESS) to address persistently poor reliability for customers experiencing an excessive number of hours of outages per year, particularly in rural and remote areas serviced often by long, radial feeders with limited or no redundancy. This investment includes two complementary solutions: (i) grid-scale BESS that provide front-of-meter backup power to communities through a microgrid configuration; and (ii) the Residential Battery Energy Storage Program, which installs a behind-the-meter system for eligible residential customers.

There are no planned capital expenditures for Orillia Rate Zone (RZ) or Peterborough RZ

1.0 INVESTMENT NEED

Hydro One faces a persistent and material reliability gap for a subset of customers, most notably in First Nations communities and rural areas served by long, radial distribution feeders. These customers tend to experience longer and more frequent outages than the system average as a result of the inherent limitations of long radial feeders in a rural network topology. In many cases, grid supply cannot be restored until faults are physically located and repaired, resulting in extended interruption durations relative to customers served by feeders with better reliability. Figures 1 and 2 below provide a comparison of reliability metrics between Hydro One average customers and Hydro One First Nations customers.

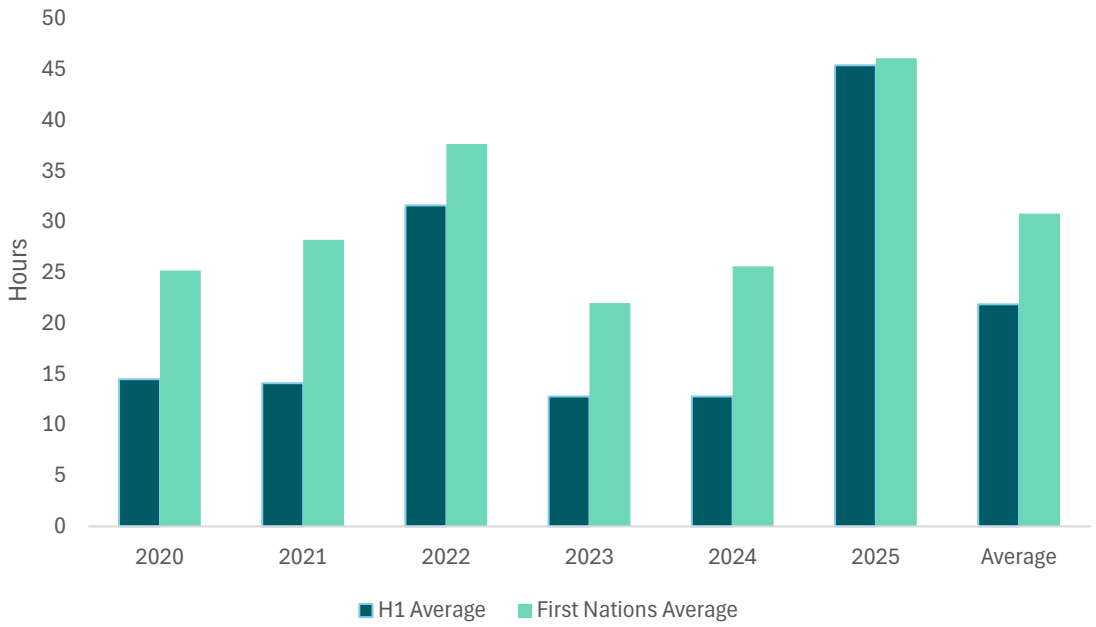


Figure 1: Comparison of Hydro One and First Nations Customers Interruption Duration

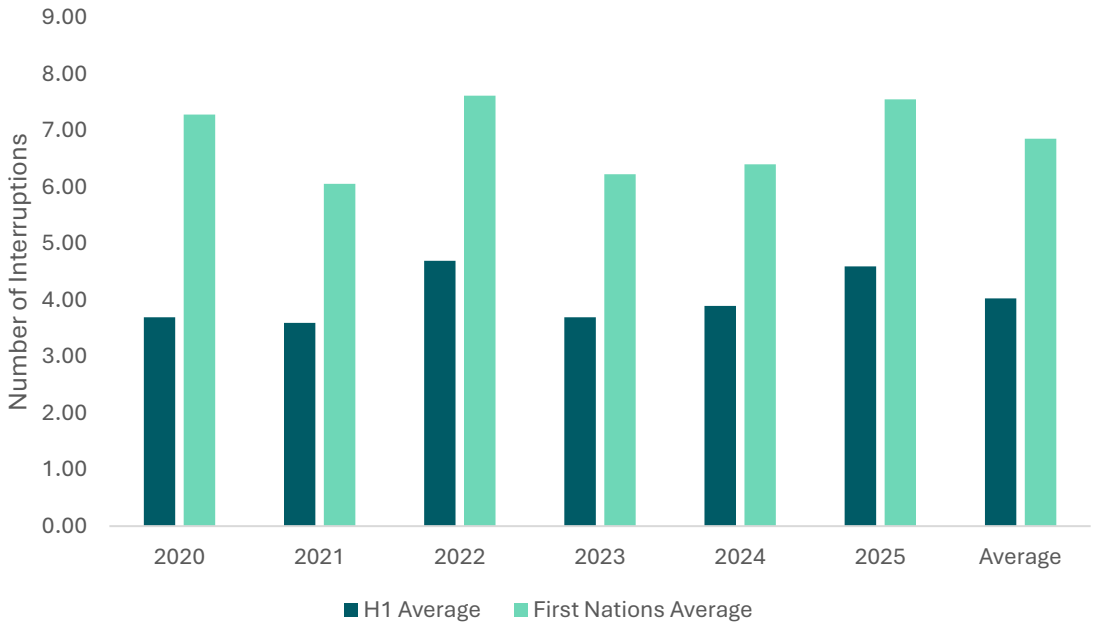


Figure 2: Comparison of Hydro One and First Nations Customers Interruption Frequency

Figures 1 and 2 above show that from 2020 to 2025, a typical Hydro One customer experienced 22 hours of outages and 4.0 sustained interruptions per year on average, whereas the average performance in a First Nations community was approximately 31 hours of outages and 7 sustained interruptions per year. The reliability data shown in Figures 1 and 2 represent all interruption causes including Force Majeure and Loss of Supply. Relative to the typical Ontario customer, this represents a 41% increase in the duration of outages and a 75% increase in the number of sustained interruptions per year. Note that Hydro One's system performance in 2022 and 2025 was exceptionally poorer than other years due to two generational storms; the May 2022 derecho and March 2025 ice storm, respectively, which caused unprecedented outages and asset damage across the province.

For affected communities, prolonged outages create health, safety, and economic risks. Households, schools, businesses, and community services may lose access to heating, refrigeration, and medical equipment. These impacts are particularly acute in First Nations

communities, where outages can affect essential aspects of daily life, food security, and community wellbeing.

Traditional poles-and-wires solutions are often not viable to improve reliability for rural customers and communities. Improving reliability through conventional means would require significant capital investment in new feeders or redundant supply over long distances to serve relatively small customer populations. As a result, these approaches are frequently cost prohibitive and deliver limited incremental benefits.

Battery storage systems provide a targeted solution that supplies temporary power during upstream outages, regardless of cause. These systems improve reliability by providing localized backup power and offer a scalable and flexible alternative to traditional infrastructure investments. The proposed investment directly addresses the needs of the customers most affected by outages, aligns with customer preferences for improved service, and represents a prudent alternative where conventional infrastructure upgrades are not practical or cost-effective.

2.0 INVESTMENT DESCRIPTION

Advancements in battery technology have positioned BESS as a viable solution for improving reliability. BESS can provide a secondary supply during a system outage and can temporarily support customer loads on a feeder section when the upstream power supply is interrupted, and may also support other grid services.

For many First Nations communities and rural residential customers, battery energy storage is the only economically viable option to improve reliability as traditional wires alternatives in these areas are either inadequate or cost prohibitive.

Battery storage can be 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 battery energy storage systems that can back up a whole community. To that end, this investment consists of two streams: (i) the Grid-Scale BESS program, and (ii) the Residential BESS program.

Grid Scale Battery Energy Storage Program

The grid-scale battery storage program targets rural communities served by long, radial feeders with persistently poor reliability at locations where traditional reliability solutions are not economically viable or practical, with a particular focus on First Nations communities experiencing frequent and prolonged outages.

Traditional wires solutions are often not a practical means of improving reliability in rural and First Nations communities due to their significant costs and limited incremental resilience benefit. For example, the Ojibway Nation of Saugeen is served from the end of a 98 km radial circuit. To provide an alternate supply source through a conventional wires solution would require construction of an additional feeder over a comparable distance. Excluding other associated infrastructure requirements, such as station upgrades, the cost of constructing a second 98 km feeder is estimated to be approximately three times greater than the cost of deploying a grid-scale BESS.

In addition to the higher cost, the reliability benefits of a wires solution are limited. While a second feeder would provide an alternate supply path, the community would remain exposed to many of the same outage drivers affecting the surrounding distribution system. By contrast, a grid-scale BESS can provide backup power during outages regardless of the upstream cause, reducing both the frequency and duration of customer interruptions. As a result, grid-scale BESS represents a technically and economically viable and resilient solution for improving service reliability in these communities.

The First Nations Reliability Report, D-SS-04 Attachment 1, provides interruption duration and frequency for First Nations communities and compares the results to Hydro One's system-wide average performance over the 2020-2025 period. The report shows 40 communities with average annual outage durations exceeding 30 hours of interruption on average per year. Additionally, 63 communities have average annual interruption duration above the system average of 22 hours/year during the 2020 – 2025 period.

While these communities may be candidates for a grid-scale BESS solution, a variety of factors may affect project viability including community support, the availability of suitable

land for battery installation, permitting and environmental considerations, and distribution system configuration constraints.

Recognizing this uncertainty, Hydro One proposed three levels of investment for the grid-scale BESS program through its Customer Engagement Survey (SPF Section 1.6, Attachment 1, p. 554 – 555, 619 – 620). The draft plan proposed 30 projects, corresponding to the 40 communities that meet the current selection criteria, recognizing that some projects will prove to be infeasible. The spend-more option proposed 50 projects, reflecting the broader set of 63 communities whose outage duration exceeds the system average, while maintaining contingency for projects that may not proceed. The spend-less option proposed 10 projects as a lower investment alternative.

Customer engagement results indicated that a majority of participating customers supported the draft plan, while a smaller proportion preferred the spend less option. In consideration of this feedback, Hydro One refined the program scope and proposes to undertake 25 grid-scale BESS projects during the plan period (which would correspond to approximately 4,000 customers assuming an average of 160 customers per community). This approach balances customers' preferences with practical delivery considerations and maintains flexibility to address the communities experiencing the greatest reliability challenges.

Residential Battery Energy Storage Program

The Residential BESS program is targeted at individual residential customers, particularly those in rural areas who have experienced poor reliability, with average outage durations exceeding 50 hours per year in at least two of the preceding five years. The number of eligible customers based on historical data is around 20,000. Under this program, residential battery energy storage systems are installed at customer premises to provide backup power during service interruptions.

The Residential BESS program is informed by customer outreach and engagement to identify participants who both meet defined eligibility requirements and are willing to participate in the program. The customer selection criteria are designed to ensure that the battery systems are operated within their technical limits. To qualify for the program,

customers are required to meet the following criteria to ensure the battery system will not sit idle for extended periods of the year and will be operated within its rated power limits:

- Experience an average annual outage duration exceeding 50 hours in at least two of the past five years
- be non-seasonal/year-round residents, to maximize the potential benefits of the battery.
- billed at the residential rate class
- not rely on electric space heating, to remain within battery power constraints
- live in single dwellings.

In addition to the customer eligibility criteria, participants are required to meet the following technical site requirements:

- reliable internet signal to enable remote monitoring and control; and
- sufficient wall space in a temperature-controlled room to accommodate the batteries.

The program has demonstrated a high level of success in improving customer reliability outcomes and overall service experience. Since program inception, participating customers have experienced an average reduction in outage duration of approximately 90%. In aggregate, the program has reduced customer outage time by over 1.6 million customer-minutes (approximately 27,600 hours). On average, the Residential BESS program has mitigated approximately 95% of monthly outage duration, with peak performance approaching near-complete mitigation of outage impacts.

Customer feedback on the program has been consistently positive. In a recent survey of more than 200 participating customers, 98% of respondents indicated satisfaction with both the program and the performance of the residential battery system. Respondents frequently cited increased peace of mind and improved continuity of essential services during outages.

To date, the Residential BESS program has delivered reliability improvements for participating customers, at a lower cost than conventional wires solutions. For illustrative

purposes, a traditional wires solution to serve approximately 60 Residential BESS program-eligible customers on the Dorset DS F1 feeder would be expected to require roughly 64 km of new line construction, at an estimated total cost of approximately $37M. In comparison, a hypothetical Hydro One-owned portfolio of residential battery storage systems for those specific 60 customers would be an expected total cost of approximately $1.7M, representing a cost reduction of approximately 95%. Unlike a traditional wires solution, which remains exposed to weather-related risks, residential battery storage directly mitigates outage impacts by providing localized backup power to those individual customers, regardless of the cause or location of the upstream outage. This targeted approach is particularly appropriate for feeders such as Dorset DS F1, which serves a high proportion of seasonal customers, and investments can be focused on those year-round customers most affected by outages.

Hydro One proposes to install residential battery systems at approximately 5,400 homes across the province over the plan period. These volumes are principally informed through customer engagement preferences for reliability improvements, balanced with execution-related considerations from Hydro One's experience over the last three years, including program scalability (installer availability, installer certification requirements, and vendor onboarding timelines), deployment logistics (regional coordination, site access constraints and installation scheduling), and observed participation dynamics (customer attrition through outreach, agreement acceptance, and site assessment requirements). Installation-related considerations, including customer acceptability and technical constraints, have historically resulted in only a portion (around 40%) of targeted eligible customers progressing to installation, while licensed installer requirements continue to pose challenges to scaling. Accordingly, the projected pace of deployment reflects Hydro One's considered view of a realistic, achievable, and prudent level of execution under the proposed program.

3.0 OUTCOMES

Reliability improvement projects using BESS solutions will:

- Reduce the impact of outages, and respond to concerns raised by customers and communities;
- Reduce outage durations and frequency for customers experiencing worse-than-average reliability; and
- Provide a cost-effective solution for reliability improvement.

The BESS solutions can also provide distribution system ancillary services (e.g., peak shaving and voltage support); however, these are secondary use cases of the BESS asset. Any consideration of such services will be strictly conditional on there being no material impact to the primary use case of reliability improvement through reducing outage duration and frequency.

3.1 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 poor reliability by reducing the duration and number of outages for these customers.
Operational Effectiveness	• Improve reliability for customers experiencing an excessive number of hours of outages per year by temporarily supplying these customers from battery energy storage systems when the normal supply source is lost.

4.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 rate period.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	129.8	37.6	57.0	84.1	198.9	204.1	147.4	691.4
Less Removals	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.1
Less Capital Contributions	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**129.8**	**36.3**	**56.9**	**84.0**	**198.8**	**204.1**	**147.4**	**691.3**

2023-2027 EXPENDITURES

As outlined in DSP Section 3.9, Subsection 3.9.2.1, increases in demand-driven investments resulted in deferral of several planned investments including Energy Storage projects. As a result, 2023-2027 expenditures for this investment are forecasted to be $93.5M lower than planned. On a volume basis, the program is forecast to deliver one grid-scale BESS project and approximately 360 residential battery installations (including installations supported by $1.0M in IESO Grid Innovation Fund funding), relative to a planned portfolio of six grid-scale BESS projects and approximately 1,300 residential battery installations. This reflects deferral of a significant portion of the originally planned scope, including approximately 940 residential battery installations and five of the six planned grid-scale BESS projects. These investments also experienced the general cost pressures outlined in SPF Section 1.8, Subsection 1.8.2 and 1.8.3.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, Hydro One expects to complete 25 grid-scale battery energy storage projects and 5,400 residential battery installations. This forecast reflects ongoing reliability needs and is expected to materially improve reliability for customers and communities experiencing prolonged outages. It also reflects higher deployment costs associated with higher volumes as the program scales beyond its initial implementation phase.

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Grid-scale BESS Program

The grid-scale BESS project cost forecast is based on the Lac La Croix First Nation BESS project. Lac La Croix is representative of the communities targeted under this program in terms of system size, customer population, operating requirements, and the logistical challenges associated with remote locations. As a result, the project's current scope, schedule, and cost estimates provide the basis for forecasting future grid-scale BESS deployments.

A typical grid-scale BESS project is delivered over a four-year lifecycle, with limited spending during early development and community engagement activities, increasing through detailed design and procurement, peaking during EPC execution, and declining during final installation, commissioning, and in-servicing. This expenditure pattern is consistent with the Lac La Croix project and forms the basis of the forecast spending profile for future deployments. Hydro One plans to initiate 12 projects in 2028, 8 projects in 2029, and 5 projects in 2030. Based on this schedule, 20 projects are expected to be placed in service by the end of 2032, with the remaining 5 projects expected to be in service in 2033. Annual spending varies based on the mix of projects progressing through each phase of the delivery cycle.

The largest cost component is the Engineering, Procurement and Construction (EPC) contract, which includes detailed engineering, equipment procurement, factory testing, installation, commissioning, and in-servicing. Battery equipment represents only a portion of total project costs. Other key cost drivers include site preparation, land acquisition, access requirements, distribution system upgrades, switching and protection equipment, SCADA connectivity, interconnection facilities, and other community-specific infrastructure requirements. Table 3 provides an estimated breakdown of the project costs for the Lac La Croix grid-scale BESS project, which is a good representative on average of future project costs.

Table 3 - Cost Breakdown of Typical Grid-Scale BESS Project

Item	Percentage Cost
Construction	33%
Battery Equipment	23%
Indirect Costs[4]	21%
Project Management	12%
Engineering	7%
Interconnection	3%
Land Acquisition	1%

Residential BESS Program

The capital cost forecast for this program is based on a quote obtained from the current Residential BESS program vendor for a turnkey solution under a Hydro One–owned asset model. The forecast assumes an average installed cost of approximately [redacted] per system and annual installations of roughly 1,080 units over the plan period.

EB-2021-0110 Settlement Commitment to Consider Third Party Ownership

Pursuant to the commitment made in the EB-2021-0110 Settlement Proposal, Hydro One undertook competitive procurements to assess third-party ownership (Energy-as-a-Service) and Hydro One-owned delivery models for both Grid-Scale and Residential BESS applications. The procurement results for Residential BESS demonstrated that the Energy-as-a-Storage (EaaS) model provides the higher lifecycle cost option and is expected to deliver approximately 20% higher costs over 15 years and approximately 45% higher costs over 20 years relative to the Hydro One Owned model. For grid-scale BESS, the EaaS model showed approximately 45% higher cost than Hydro One-owned assets. Based on these results, Hydro One proposes to own and operate all BESS assets included in the 2028-2032 planning period. Further details on the procurement process, evaluation methodology, and results are provided in Attachment 2.

[4] Indirect costs include contingency, overhead and interest.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended alternative.

ALTERNATIVE 1: DO NOTHING

This alternative would not address the current reliability challenges experienced by vulnerable customers. Without the proposed investments, these customers would remain exposed to sustained and frequent service interruptions, with no meaningful improvement in reliability outcomes. Accordingly, this alternative is not recommended, as it fails to meet the objective of improving service reliability for vulnerable customer segments.

ALTERNATIVE 2: CONVENTIONAL POLES AND WIRES SOLUTION

This alternative is rejected as it would not be a cost-effective or practical means of improving reliability for vulnerable customers. Conventional wires solutions would require substantial investment in new feeders or distribution infrastructure to serve relatively few customers, while remaining exposed to the same outage drivers affecting the existing system, including severe weather, vegetation contact, and difficult terrain.

ALTERNATIVE 3: ENERGY STORAGE SOLUTION – ACCELERATED PACE

Under the accelerated alternative, Hydro One would deploy 50 grid-scale BESS projects and install Residential BESS systems at approximately 8,000 homes over the 2028-2032 period, improving reliability for up to 16,000 vulnerable customers.

This alternative was developed to assess the benefits of accelerating reliability improvements for customers experiencing long outage durations. The proposed 50 grid-scale projects would address approximately 80% of communities with outage durations above the system average, recognizing that some projects may not proceed due to technical, community, or site-specific constraints. The proposed 8,000 Residential BESS installations are the estimated maximum achievable installations over the planning period. This reflects an expected implementation rate of approximately 40% of the roughly 20,000 targeted eligible customers, after accounting for customer attrition due to participation agreement non-acceptance, installation constraints, and uncertainties related to the BESS technology selection.

While this alternative would provide reliability benefits to a larger number of customers than the proposed plan, Hydro One determined that the proposed plan represents the more appropriate balance of reliability benefits and cost. Customer engagement results were generally consistent with this conclusion, with a significant portion of surveyed customers expressing a preference for a lower-cost option. Accordingly, Hydro One did not select the accelerated alternative.

ALTERNATIVE 4: ENERGY STORAGE SOLUTION – DECELERATED PACE

Under the decelerated alternative, Hydro One would deploy 10 grid-scale BESS projects and install Residential BESS systems at approximately 2,000 homes over the 2028-2032 period, improving reliability for approximately 3,500 vulnerable customers.

The 10 grid-scale projects would address approximately 25% of First Nations communities that experience greater than 30 hours of outage per year. The proposed 2,000 Residential BESS installations would achieve approximately 25% of the estimated maximum achievable installations.

While this alternative requires a lower level of investment, it would provide reliability benefits to significantly fewer customers than the proposed plan. Hydro One determined that the proposed plan provides a more appropriate balance between cost and the reliability benefits delivered to customers in alignment with customer engagement results.

ALTERNATIVE 5: ENERGY STORAGE SOLUTION – DRAFT PLAN PACE (RECOMMENDED)

Under this alternative, Hydro One will implement 25 grid-scale BESS solutions and deliver the Residential BESS program to 5,400 homes over the 2028-2032 period. Together, these investments are expected to improve reliability for up to 9,400 vulnerable customers currently experiencing poor reliability. This is in line with Phase 2 of the Customer Engagement Survey Draft Plan to improve reliability for around 10,000 customers (SPF Section 1.6, Attachment 1, p. 554 – 555, 619 – 620).

This alternative was selected because it improves reliability for vulnerable customers and reflects Hydro One's assessment of the practical considerations associated with delivering

these programs, informed by its experience during the current rate period. Customer engagement results were generally consistent with this conclusion and demonstrated strong support for investments targeted at improving reliability for affected customers.

6.0 EXECUTION RISK AND MITIGATION

The main risks concerning project execution for grid-scale battery storage include the following:

- **Procurement and Logistics Risks**: Battery availability due to worldwide demand and uncertainty around global supply chain. These risks are mitigated by selecting a vendor through a competitive RFP process and 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 and considering crown land parcels that can be allocated to the project through the Ontario Ministry of Natural Resources and Forestry (MNRF).
- **Telecommunications Risks:** Cellular signal strength at the battery storage sites may not be sufficient to monitor battery system performance, send control signals, and receive telemetry data. This risk is mitigated by verifying signal strength is suitable before selecting the battery site, or by utilizing other technologies such as satellite, fiberoptics, and point-to-point radio for communication at these sites.

The main risks concerning project execution for Residential battery storage include:

- **Procurement and Logistics Risks:** Battery availability due to worldwide demand and uncertainty around the global supply chain. Unit costs are also subject to market factors, including vendor selection, BESS technology, and product availability, which may affect the number of installations delivered within the 2028–2032 planning period. These risks are mitigated by selecting a vendor through a competitive RFP process and working together with the vendor in the early stage of the program.
- **Telecommunications Risks:** Reliable communications are required to monitor battery system performance and receive telemetry data. Inadequate internet

connectivity at a customer's premises may limit the ability to support these functions. This risk is mitigated by requiring customers to have a stable and reliable internet connection as a prerequisite for participation in the program. Internet connectivity will be assessed as part of the site qualification process, and installations will only proceed at locations where sufficient communications capability is available to support the operational requirements of the battery system.

- **Regulatory and Code Compliance Risks**: Residential battery system installations are subject to evolving electrical codes, safety standards, and local permitting requirements. Changes in applicable codes or standards may restrict installation at certain customer locations or require additional protective measures, potentially increasing per site costs, affecting installation schedules, or in some cases, result in the site, or the broader project scope, no longer being feasible to execute. These risks are mitigated through ongoing monitoring of regulatory and code developments, standardized system designs, and close coordination with authorities having jurisdiction to ensure compliance and minimize implementation impacts.

First Nations Reliability Report 2025



Witness: Peter Faltaous

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1.0 PURPOSE

Pursuant to Section 5.0 of the Settlement Proposal of the Custom IR Application (2023-2027) for Hydro One (EB-2021-0110), Hydro One Distribution committed to prepare and provide an Indigenous Reliability Report as part of its next cost-based rate application. This report provides the results of the reliability data analysis performed for the 89 First Nations communities listed in Hydro One's Distributor Licence. The analysis excludes communities served by Hydro One Remote Communities Inc.

Hydro One also received feedback through a customer engagement exercise conducted by Innovative Research Group (Innovative).[1] This engagement provided valuable insights into the importance that First Nations communities place on reliable electricity service, complementing the quantitative reliability data presented in this report.

2.0 NATURE OF FIRST NATIONS SUPPLY

First Nations communities are often located at the end of rural distribution feeders that are typically radial and longer than an average Hydro One feeder. As a result, these lengthy feeders have increased exposure and are vulnerable to interruptions with potentially long outage durations as there are no alternate supply sources.

3.0 DATA SOURCES

Two data sources were used to inform the analysis of First Nations communities' reliability performance: community reliability metrics and First Nations engagement.

3.1 FIRST NATIONS ENGAGEMENT

Hydro One serves 89 First Nations communities representing close to 23,000 distribution system customers. Innovative Research Group reached out to all 89 communities and met with 18 First Nations Chiefs and/or their representatives. Through these meetings, Hydro One was able to collect feedback on Hydro One's 2028-2032 draft investment plan. This engagement exercise built upon a previous engagement conducted in 2024 to collect input

[1] SPF Section 1.6, Attachment 1, p. 611 – 622

from First Nations Chiefs and/or their representatives on their electricity needs and general preferences.

As per SPF Section 1.6, Attachment 1 p. 611 – 622, the results of the customer engagement exercise showed that First Nations communities are generally supportive of the following objectives:

1. Improve day-to-day reliability by 2032;
2. Reduce the risk of outages and shorten restoration times related to severe weather; and
3. Improve reliability for around 10,000 customers through targeted initiatives.

Representatives from First Nations communities were supportive of reliability-focused investments, since First Nations communities statistically experience poorer reliability than Hydro One customers on average.

3.2 COMMUNITY RELIABILITY DATA

This report provides the average annual outage duration and outage frequency for each First Nations community served by Hydro One Distribution and listed in Hydro One's Distribution Licence over the 2020-2025 period. In addition, the report includes an aggregate breakdown of outage causes across all on-reserve First Nations customers, showing the percentage contribution of each outage cause to overall outage duration and outage frequency.

As seen in Figures 1 and 2, the leading causes of service interruption are tree contacts and defective equipment. It should be noted that traditional investments made to address these vegetation and equipment issues have limited ability to improve reliability for many First Nations communities. These communities are often served by long radial feeders, where customers are exposed to outages occurring anywhere along the circuit. While vegetation maintenance and asset renewal can reduce outage frequency, they cannot eliminate outages, and even low failure rates can result in significant interruption duration for customers at the end of the line.

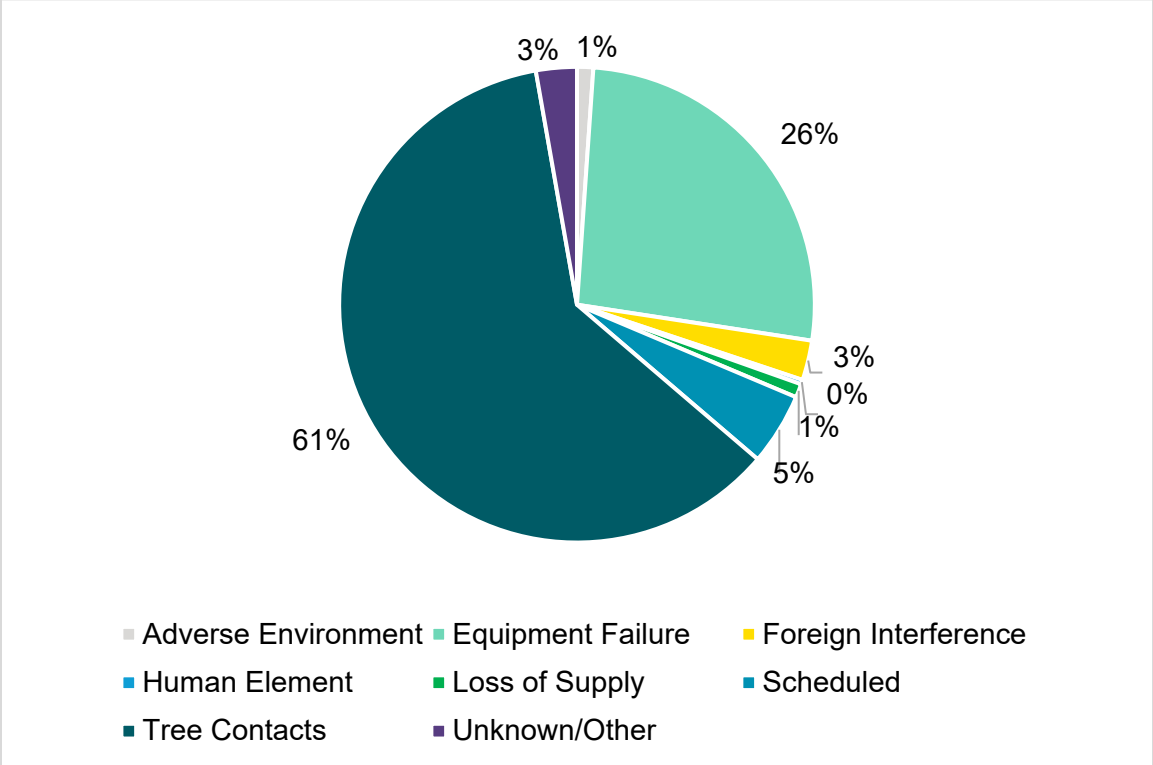


Figure 1: Percentage of Outage Causes to Outage Duration for First Nations Communities (2020-2025)

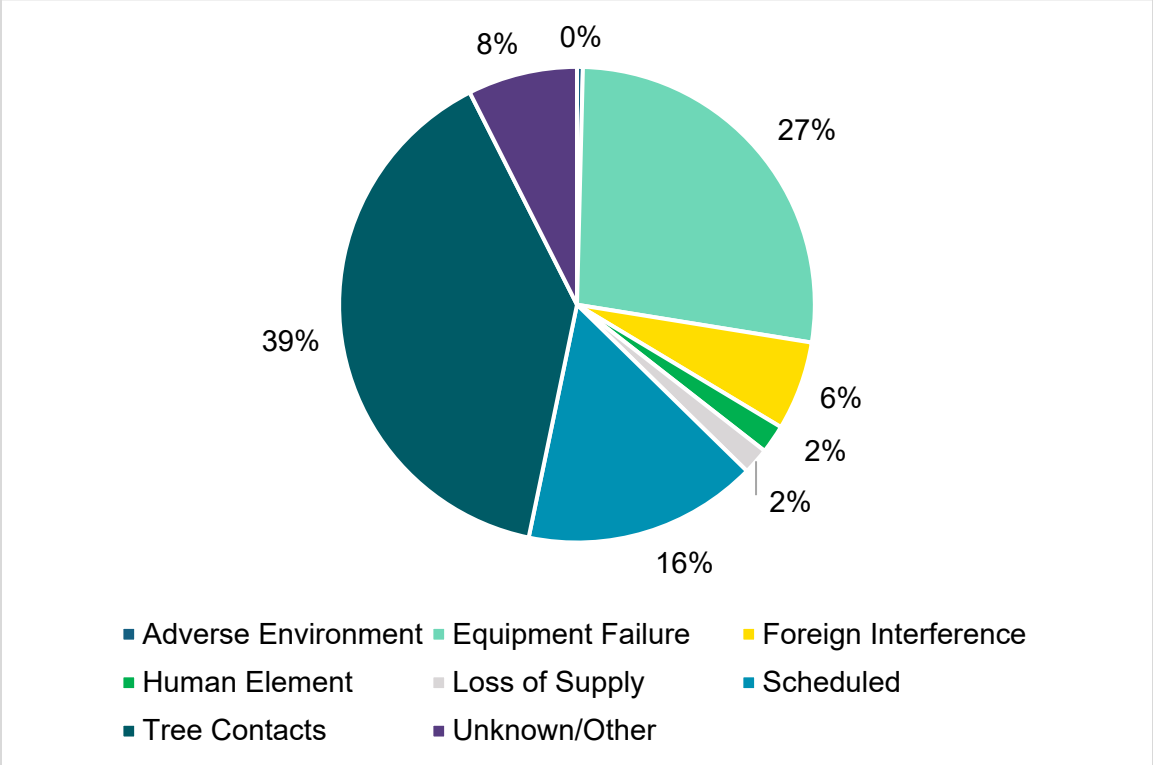


Figure 2: Percentage of Outage Causes to Interruption Frequency for First Nations Communities (2020-2025)

On average, Hydro One customers residing within First Nations communities experienced nearly 31 hours of interruption and about 7 sustained interruptions per year. The average Hydro One customer interruption duration and frequency throughout the same period are approximately 22 hours and 4 interruptions per year, respectively. Figure 3 below provides a distribution of annual average outage durations by each community for all First Nations communities over the 2020-2025 period, along with the associated annual number of interruptions as well as Hydro One customer average values for comparison. A complete list of reliability data for all communities can be found in Appendix A of this report.

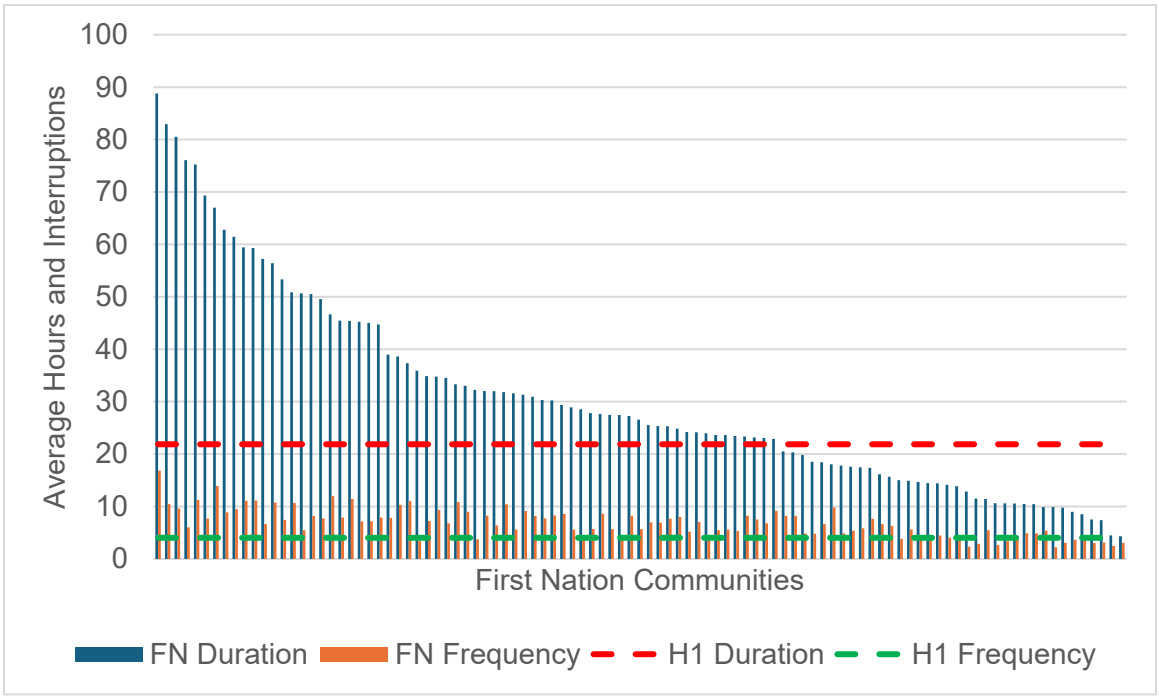


Figure 3: Reliability for First Nations Communities Sorted by Annual Average Outage Duration (Hours) for 2020-2025 vs. Hydro One Customer Average Values

4.0 CONCLUSION

The reliability data presented in this report shows that First Nations communities experience poorer reliability than the average Hydro One customer. This finding supports Hydro One investments that can improve reliability for First Nations communities with poor reliability.

Appendix A: Reliability Data by First Nations Community[2]

First Nations Community	Average Annual Hours of Interruption (2020-2025)	Average Annual Number of Interruptions (2020-2025)
Abitibi 70	25	8
Alderville First Nation	57	7
Aroland First Nation	45	11
Bear Island 1	12	3
Big Grassy River 35G	20	8
Big Island Mainland 93	21	8
Chapleau 74A	32	6
Chapleau Cree Fox Lake	24	5
Chief's Point 28	11	4
Chippewas of Georgina Island First Nation	83	10
Chippewas of the Thames First Nation 42	29	4
Christian Island 30	51	8
Christian Island 30A	45	7
Constance Lake 92	18	10
Couchiching 16A	10	3
Curve Lake First Nation 35	76	6
Dalles 38C	9	4
Dokis 9	56	11
Duck Lake 76B	23	5
Eagle Lake 27	9	4
English River 21	30	8
Factory Island 1	4	3
French River 13	18	5
Georgina Island 33	36	3
Henvey Inlet 2	61	9
Hiawatha First Nation 36	51	5

[2] List of communities corresponds to the list of Band Names as described in Hydro One Networks Inc. Distributor Licence updated on July 11, 2024.

First Nations Community	Average Annual Hours of Interruption (2020-2025)	Average Annual Number of Interruptions (2020-2025)
Indian River	50	8
Islington 29	20	5
Kenora 38B	11	5
Kettle Point 44	15	4
Lac des Milles Lacs 22A1	59	11
Lac Seul 28	32	6
Lake Helen 53A	7	3
Lake Nipigon Ojibway First Nation	35	7
Long Lake 58	27	6
Long Lake 77	28	6
Magnetawan 1	63	9
Manitou Rapids 11	10	5
Matachewan 72	16	7
Mattagami 71	67	14
Mississagi River 8	19	5
Moose Point 79	81	10
Moravian 47	28	9
Munsee-Delaware Nation 1	27	4
Naiscoutaing 17A	53	7
Neguaguon Lake 25D	59	11
New Credit 40A	8	3
New Post 69A	13	2
Neyaashiinigmiing	29	6
Nipissing 10	10	5
Ojibway Nation of Saugeen	75	11
Oneida 41	11	3
Osnaburgh 63A	45	8
Osnaburgh 63B	45	8
Parry Island First Nation	45	7
Pays Plat 51	27	6

First Nations Community	Average Annual Hours of Interruption (2020-2025)	Average Annual Number of Interruptions (2020-2025)
Pic Mobert Reserve North	32	8
Pic Mobert Reserve South	32	8
Pic River 50	31	8
Pikwakanagan	24	7
Rainy Lake 17A	51	11
Rainy Lake 17B	89	17
Rainy Lake 18C	14	4
Rainy Lake 26A	26	7
Rama 32	32	4
Rat Portage 38A	27	8
Rocky Bay 1	24	6
Sabaskong Bay 35D	23	8
Sagamok	25	7
Sand Point First Nation	18	5
Sarnia 45	4	2
Saug-A-Gaw-Sing 1	23	9
Saugeen 29	10	5
Scugog 34	11	3
Seine River 23A	35	9
Serpent River 7	14	4
Shawanaga 17	24	5
Shawanaga 17B	39	8
Sheguiandah 24	16	6
Sheshegwaning 20	32	10
Shoal Lake 39A	37	11
Shoal Lake 40	47	12
Six Nations 40	14	4
Slate Falls Indian Settlement	35	7
Sturgeon Falls 23	33	9
Sucker Creek 23	15	6

First Nations Community	Average Annual Hours of Interruption (2020-2025)	Average Annual Number of Interruptions (2020-2025)
Thessalon 12	24	4
Tyendinaga Mohawk Territory	14	4
Wabauskang 21	15	4
Wabigoon Lake 27	17	6
Wahnapitae 11	10	2
Wahta Mohawk Territory	69	8
Walpole Island 46	23	7
West Bay 22	17	8
Whitefish Bay 32A	31	9
Whitefish Bay 33A	39	10
Whitefish Bay 34A	29	9
Whitefish Lake 6	25	8
Whitefish River 4	18	7
Wikwemikong Unceded 26	23	8
Zhiibaahaasing 19A	33	11

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BESS Third-Party Solutions

RFP Results Report

1.0 OVERVIEW

In EB-2021-0110, Hydro One Distribution committed to undertake competitive procurement processes for reliability services from energy storage solution providers for projects over the 2025-2027 period and, in this regard, actively seek economic participation or equity investment opportunities from First Nations as part of its standard procurement practice.

To address this commitment, Hydro One explored the potential for third-party ownership of Battery Energy Storage Systems ("BESS") deployed to improve reliability for customers experiencing frequent and prolonged outages. Hydro One evaluated and compared the following procurement approaches from both a technical and financial perspective:

1. **Hydro One-owned approach:** Hydro One invests capital to design, build, own, and operate BESS assets, with the primary objective of improving customer reliability.
2. **Energy-as-a-Service ("EaaS") approach:** A third-party vendor designs, builds, owns, and operates the BESS assets to satisfy Hydro One's reliability requirements, and Hydro One procures reliability services through a long-term EaaS arrangement.

For residential BESS, the analysis demonstrated that the Hydro One-owned model provides a more cost-effective solution over the expected 15 to 20-year asset life. For grid-scale BESS, the RFP process determined that the only proposal that satisfied the technical and commercial requirements had a net present value ("NPV") that was 45% higher than that of an equivalent Hydro One-owned asset. Accordingly, the Hydro One-owned model was found to be the more economical option for both residential and grid-scale BESS applications.

The following sections provide an overview of Hydro One's efforts to procure EaaS solutions under both BESS programs, including the competitive procurement process, evaluation outcomes, and conclusions regarding the relative merits of the EaaS and Hydro One-owned approaches.

2.0 INDIGENOUS PARTICIPATION

To fulfill the Indigenous participation component of the supply chain process, Hydro One developed and implemented the following procurement processes:

- Through its Indigenous Partnerships and Business Development team, Hydro One publishes information about upcoming requests for proposal (RFPs) to Indigenous contacts, groups, and vendors to facilitate participation.
- Hydro One engages relevant First Nation communities before issuing an RFP to inform them about the procurement process and how to participate in their own name or through a project consortium.
- Hydro One includes a specific Indigenous questionnaire with the tender package for vendors to fill out and allocates 15% of the bid evaluation score to Indigenous participation. Hydro One notifies potential vendors of this policy in the RFP documents.

3.0 THE RESIDENTIAL BESS PROGRAM

The Residential BESS program targets individual residential customers, primarily in rural areas, who have experienced poor reliability, defined as average outage durations exceeding 50 hours per year in at least two of the preceding five years. Under the program, residential battery energy storage systems are installed at customer premises to provide backup power during service interruptions. The program scope contemplated the deployment of approximately 399 residential battery systems over a three-year period (approximately 133 installations annually), with installations distributed across Hydro One's service territory and concentrated primarily in Eastern Ontario.

3.1 RFP PROCESS

Hydro One Networks Inc. (HONI) issued a Request for Proposal (RFP) to procure and deploy Behind-the-Meter (BTM) Residential Battery Energy Storage Systems (RBESS) at scale. The RFP solicited 38 vendors to provide solutions capable of meeting defined technical specifications, delivery timelines, and operational support requirements across HONI's service territory. Two delivery approaches were solicited and evaluated:

- **HONI-owned model:** Vendors provide turnkey engineering, procurement, construction (EPC), and ongoing support, with HONI retaining ownership of the assets.
- **EaaS model:** Vendors own, operate, and maintain the assets, with HONI paying recurring service fees.

HONI received bids from 11 suppliers submitting 13 proposals (10 HONI-owned and 3 EaaS).

3.2 EVALUATION APPROACH

Vendor submissions were evaluated using a structured, multi-stage process designed to assess technical and operational compliance and economic competitiveness. The evaluation methodology was developed to support a fair, transparent, and defensible comparison of proposals.

3.2.1 TECHNICAL/OPERATIONAL EVALUATION

All proposals were initially subject to a technical screening to confirm compliance with the mandatory requirements set out in the Request for Proposal (RFP). This review assessed system performance, operating characteristics, safety and regulatory compliance, vendor qualifications, and the overall completeness of each submission. Key mandatory requirements included:

- **Capacity and Performance:** The proposed residential battery energy storage system (RBESS) was required to meet specified performance criteria, including maximum discharge capacity, round-trip efficiency, backup duration, operational controls, and the ability to operate seamlessly in grid-connected, islanded, and demand-control modes.

- **Operating Criteria:** The RBESS was required to operate reliably under prescribed environmental conditions, including temperature, humidity, noise, and seismic performance requirements.
- **Safety and Regulatory Compliance:** The RBESS was required to meet applicable safety and certification standards, including UL and CSA certification requirements.
- **Vendor Qualifications and Experience:** Vendors were required to demonstrate the capability and experience necessary to deliver a program of similar scope and complexity, including experience installing and operating battery energy storage systems.

Vendors that did not satisfy the mandatory technical and operational requirements were not advanced to the subsequent stages of the evaluation process.

Following this process, five proponents under the HONI-owned model and two proponents under the Energy-as-a-Service (EaaS) model advanced to the economic evaluation stage. The remaining proponents were not advanced because they did not satisfy one or more mandatory technical, operational, or vendor qualification requirements. Deficiencies included:

- Failure to demonstrate that the proposed system could meet the required capacity, performance, or maximum output requirements.
- Failure to demonstrate compliance with specified environmental and operating requirements, including minimum operating temperature criteria.
- Proposed system designs that were not suitable for residential installations due to their size and space requirements.
- Incomplete proposal submissions that did not provide the information required for evaluation.
- Insufficient demonstrated experience installing battery energy storage systems or delivering projects of comparable scope and complexity.

3.2.2 ECONOMIC EVALUATION

Following completion of the technical and operational evaluation, Hydro One conducted an economic assessment using a standardized net present value ("NPV") methodology to evaluate and compare the lifecycle costs of the competing proposals.

The NPV analysis assessed projected cash flows over a 20-year horizon and incorporated key assumptions regarding the weighted average cost of capital (5.62%), inflation (2% annually), and applicable tax impacts, including the capital cost allowance ("CCA") tax shield and income tax recovery provisions. The resulting NPVs represent the after-tax present value of the costs associated with each procurement scenario and were used as the basis for economic comparison.

To ensure a comprehensive assessment of lifecycle costs, Hydro One evaluated the procurement options over both 15-year and 20-year horizons. These evaluation periods were selected to reflect the expected service life of the residential battery assets and to assess the long-term financial implications of each procurement model.

The results of the economic assessment, summarized below in Table 1, indicate that the Hydro One-owned model provides lower lifecycle costs than the EaaS model when evaluated over the expected 15 to 20-year service life of residential battery assets. [1]

Table 1 - Residential BESS NPV Results Comparison

Model	Vendor	Capex ($K)	OM&A ($K)/year	NPV (15 yrs) ($K)	NPV (20 yrs) ($K)
HONI-Owned	Lowest cost option	[redacted]			
EaaS	Lowest cost option				

[1] The 15- and 20-year analyses assume that annual service payments remain unchanged for the additional 5- and 10-year periods beyond the initial 10-year RFP term. Similarly, for the HONI-owned model, the analysis assumes that the annual OM&A costs remain constant beyond the 10-year mark.

Although the EaaS model eliminates the need for an upfront capital investment, the long-term cost of service payments outweighs this benefit, resulting in a higher net present value of costs. Specifically, over a 15-year evaluation horizon, the lowest-cost Hydro EaaS option was approximately 22% more expensive than the lowest-cost Hydro One owned option. Over a 20-year horizon, the cost advantage increased to approximately 46%, reflecting the cumulative impact of recurring service payments under the EaaS model.

4.0 THE GRID-SCALE BESS PROGRAM

The Grid-Scale BESS program is intended to improve reliability for remote communities that experience poor supply reliability. Under the program, a grid-scale BESS is interconnected to Hydro One's distribution system upstream of the target community, providing a secondary source of power during grid outages.

4.1 RFP PROCESS

Hydro One issued an RFP seeking proposals to EaaS for the First Nation community of Pic River through the deployment of a grid-scale BESS that would serve as an auxiliary source of power during grid outages. The procurement process evaluated a third-party ownership model under which the successful proponent would be responsible for the design, construction, ownership, operation, and maintenance of the BESS asset, while Hydro One would procure reliability services through a long-term contractual arrangement.

The RFP package specified the target BESS size, operating profile, technical requirements, and control characteristics of the proposed solution. It also established the minimum contracted power and energy capabilities that the BESS would be required to deliver whenever called upon to provide reliability services. In addition, the RFP outlined detailed operational and technical requirements that proponents were required to satisfy. Proponents were asked to submit a proposed service fee structure for a 20-year contract term, during which the solution would be expected to consistently meet its contractual performance obligations. The proposed pricing formed the basis for the economic evaluation of compliant bids.

HONI encouraged the bidders not to limit the solution offering to grid-scale BESS only, but to present innovative microgrid architectures encompassing other Distributed Energy Resources (DERs) when possible. In addition, HONI permitted bidders to use the asset outside times it provides services to HONI (as long as no conflicts arise between different use cases) to create an additional revenue stream that could enhance the overall project economics and reduce service fees.

The RFP was distributed to more than 140 potential proponents; however, only three formal bids were received. All bidders proposed a grid-scale BESS solution consistent with the requirements of the RFP. No proponent proposed an alternative configuration, identified additional use cases that could be combined with Hydro One's reliability application, or recommended a commercial structure other than annual service payments subject to escalation over the contract term. This consistency across the submissions provided additional confirmation that the proposed grid-scale BESS and annual service fee structure reflected the prevailing market approach for this application.

4.2 EVALUATION APPROACH

The bid evaluation process began with a technical and operational assessment to determine whether the proposed solutions satisfied Hydro One's requirements. Proposals that met the mandatory technical and operational criteria advanced to an economic evaluation, where the NPV of the proposed EaaS payment structure was compared against the NPV of an equivalent Hydro One-owned asset, including the costs associated with engineering, procurement, and construction ("EPC") and long-term service agreement ("LTSA") contracts. The overall process was designed to support a fair, transparent, and rigorous assessment of all proposals and to ensure that decisions were based on both technical merit and economic value.

4.2.1 TECHNICAL AND OPERATIONAL EVALUATION

The technical and operational evaluation assessed the quality and overall integrity of each proposed solution, including compliance with Hydro One's technical requirements and the proponent's ability to reliably maintain the contracted power and energy capabilities throughout the term of the agreement. The evaluation also considered a range of

additional technical and operational factors, including system design, performance, operability, maintainability, and vendor experience.

Two of the three vendors did not pass the technical/operational evaluation for reasons that included:

- Failure to demonstrate that the solution could meet technical requirements or maintain contracted capacity throughout the contract term.
- Failure to provide sufficient assurance regarding the financial strength and long-term viability of the EaaS contractor.
- Lack of demonstrated experience of comparable size and complexity and/or a limited operational track record.

4.2.2 ECONOMIC EVALUATION

Following the technical and operational evaluation, one vendor advanced to the economic assessment stage. The cost-effectiveness of the vendor's EaaS proposal was evaluated against a Hydro One-owned alternative using the NPV methodology applied in the Residential BESS analysis. To estimate the costs under a Hydro One-owned model, Hydro utilized a comparable grid-scale BESS project currently under construction to improve reliability for the First Nation community of Lac La Croix.

The methodology used to conduct the NPV analysis assessed projected cash flows over a 20-year horizon. The key assumptions encompassed a weighted average cost of capital (5.62%), inflation (2% annually), and applicable tax impacts including the capital cost allowance ("CCA") tax shield and income tax recovery provisions. The resulting NPVs represent the after-tax present value of the costs associated with each procurement scenario and were used as the basis for economic comparison. The results showed that the NPV of the EaaS annual service fees was 45% higher than the NPV of the HONI-owned asset over the same term of 20 years. Table 2 provides summary of the NPV analysis.

Table 2 - Grid-Scale NPV Results Comparison

Model	Upfront Capex ($M)	Annual OM&A ($M/year)	20-year NPV ($M)
HONI-Owned	[redacted]		
EaaS			

5.0 CONCLUSION

Based on the RFP results of the EaaS procurement model for the Residential BESS program, the NPV of a third-party owned asset is 22% and 46% higher than the NPV of a Hydro One owned asset for 15-year and 20-year evaluation horizons, respectively. For the grid-scale program, the NPV of the EaaS procurement model is 45% more expensive than the Hydro One ownership model. Accordingly, Hydro One is proposing that all energy storage assets for the 2028-2032 rate period be Hydro One owned and operated.

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Residential Behind the Meter Battery Energy Storage System – Performance Data for 2023

The breakdown of residential behind-the-meter Battery Energy Storage System (BTM BESS) performance data for units connected to Hydro One Networks Inc.'s (Hydro One) distribution system for the period, January to December, 2023, is provided below.

BTM BESS Performance Reporting - 2023					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Buchanan TS	2	0.02	24.3	24.3	100%
Centralia TS	1	0.01	9.4	9.4	100%
Cobden TS	7	0.07	260.6	251.0	96%
Constance DS	1	0.01	0.0	0.0	100%
Crosby TS	1	0.01	0.1	0.1	100%
Dunnville TS	2	0.02	21.7	21.7	100%
Goderich TS	1	0.01	0.1	0.1	100%
Herridge Lake DS	3	0.03	189.0	93.8	50%
Ingersoll TS	3	0.03	0.0	0.0	100%
Larchwood TS	2	0.02	32.4	32.4	100%
Lindsay TS	2	0.02	12.6	12.6	100%
Martindale TS	2	0.02	88.2	88.2	100%
Muskoka TS	6	0.06	269.1	210.2	78%
Parry Sound TS	1	0.01	27.4	18.1	66%
Smiths Falls TS	20	0.20	822.6	646.6	79%
Tillsonburg TS	3	0.03	20.2	20.2	100%
Trout Lake TS	28	0.28	378.8	374.5	99%
Wallace TS	9	0.09	474.6	399.6	84%
Whitefish DS	6	0.06	189.1	183.6	97%
Total	**100**	**1.00**	**2820.2**	**2386.3**	**85%**

Reference Table	
Name	**Description**
Station Name	Network connection downstream of the first level connection to Hydro One Transmission circuit
Count	Number of BESS Units connected to Station
Capacity	Total MW Capacity of BESS Units at Station
Total Customer Outage Time	Total annual customer x hours of outage time experienced by BESS units at a Station
Total Outage Duration Avoided by BESS	Total annual grid outage time (customer x hours) serviced by BESS to minimize customer outage time
% Outage hrs Mitigated	Total customer x hours of outage backed up by BESS divided by Total Customer Outage Time

Grid Scale Front of the Meter Battery Energy Storage System – Performance Data for 2023

The breakdown of Hydro One Networks Inc. (Hydro One) owned grid scale front-of-the-meter Battery Energy Storage Systems (FTM BESS) connected to Hydro One's distribution system as of December 31, 2023 is as follows:

Hydro One FTM BESS Performance Data - 2023						
Station Name	**Year**	**# of Grid Outage Events**	**Total Grid Outage (Hours) = (A)**	**BESS Operation (Hours) = (B)**	**% Outage Hrs Mitigated = (B) / (A)**	**Availability %**
Nakina DS (Aroland BESS)	2023	9	32.4	15.7	48%	92%

REFERENCE TABLE	
Name	**Description**
Station Name	Hydro One Station to which FTM BESS is connected
# of Grid Outage Events	Number of annual grid outages experienced by the BESS
Grid Outage	Total annual grid outage time (hours) experienced by BESS
BESS Operation	Total annual grid outage time (hours) serviced by BESS to minimize customer outage time
% Outage Hrs Mitigated	BESS Operation Time divided by Grid Outage Time
Availability %	% of Hours BESS was available to provide support to a grid outage divided by Total In-Service Minutes for Year

Residential Behind the Meter Battery Energy Storage System – Performance Data for 2024

The breakdown of residential behind-the-meter Battery Energy Storage System (BTM BESS) performance data for units connected to Hydro One Networks Inc.'s (Hydro One) distribution system for the period, January to December, 2024, is provided below.

BTM BESS Performance Reporting - 2024					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Arnprior TS	2	0.02	7.08	7.1	100%
Aylmer TS	1	0.01	0.45	0.5	100%
Brant TS	2	0.02	23.07	23.1	100%
Buchanan TS	2	0.02	86.28	85.2	99%
Centralia TS	4	0.04	19.65	16.4	83%
Cobden TS	12	0.12	516.15	516.1	100%
Constance DS	1	0.01	32.00	31.8	99%
Crosby TS	3	0.03	38.13	38.1	100%
Des Joachims DS	1	0.01	0.00	0.0	100%
Dunnville TS	2	0.02	34.65	34.7	100%
Goderich TS	1	0.01	36.65	36.7	100%
Havelock TS	6	0.06	46.75	46.0	98%
Herridge Lake DS	3	0.03	70.22	70.2	100%
Hinchinbrooke DS	4	0.04	9.57	9.6	100%
Ingersoll TS	14	0.14	1702.22	1702.1	100%
Kleinburg TS	1	0.01	0.82	0.8	100%
Larchwood TS	4	0.04	30.73	30.1	98%
Lindsay TS	4	0.04	367.73	367.7	100%
Martindale TS	6	0.06	36.98	37.0	100%
Mattawa DS	1	0.01	0.17	0.2	100%
Minden TS	24	0.24	544.33	544.0	100%

BTM BESS Performance Reporting - 2024					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Muskoka TS	23	0.23	952.00	915.8	96%
Muskoka TS	1	0.01	0.30	0.3	100%
Orangeville TS	2	0.02	6.87	6.9	100%
Otonabee TS	3	0.03	19.70	19.7	100%
Parry Sound TS	1	0.01	37.92	37.9	100%
Seaforth TS	1	0.01	2.45	2.5	100%
SHARBOT DS	3	0.03	49.02	49.0	100%
Smiths Falls TS	39	0.39	1751.33	1739.3	99%
Stewartville TS	1	0.01	0.05	0.1	100%
Tillsonburg TS	23	0.23	549.37	548.3	100%
Trout Lake TS	70	0.7	1757.13	1756.3	100%
Wallace TS	40	0.4	914.00	906.1	99%
Wharncliffe DS	1	0.01	11.97	12.0	100%
Whitefish DS	7	0.07	275.57	251.4	91%
Wolverton DS	3	0.03	22.60	22.6	100%

Reference Table	
Name	**Description**
Station Name	Network connection downstream of the first level connection to Hydro One Transmission circuit
Count	Number of BESS Units connected to Station
Capacity	Total MW Capacity of BESS Units at Station
Total Customer Outage Time	Total annual customer x hours of outage time experienced by BESS units at a Station
Total Outage Duration Avoided by BESS	Total annual grid outage time (customer x hours) serviced by BESS to minimize customer outage time
% Outage hrs Mitigated	Total customer x hours of outage backed up by BESS divided by Total Customer Outage Time

Grid Scale Front of the Meter Battery Energy Storage System – Performance Data for 2024

The breakdown of Hydro One Networks Inc. (Hydro One) owned grid scale front-of-the-meter Battery Energy Storage Systems (FTM BESS) connected to Hydro One's distribution system as of December 31, 2024 is as follows:

Hydro One FTM BESS Performance Data - 2024						
Station Name	**Year**	**# of Grid Outage Events**	**Total Grid Outage (Hours) = (A)**	**BESS Operation (Hours) = (B)**	**% Outage Hrs Mitigated = (B) / (A)**	**Availability %**
Nakina DS (Aroland BESS)	2024	12	64.7	43.6	67%	98%

REFERENCE TABLE	
Name	**Description**
Station Name	Hydro One Station to which FTM BESS is connected
# of Grid Outage Events	Number of annual grid outages experienced by the BESS
Grid Outage	Total annual grid outage time (hours) experienced by BESS
BESS Operation	Total annual grid outage time (hours) serviced by BESS to minimize customer outage time
% Outage Hrs Mitigated	BESS Operation Time divided by Grid Outage Time
Availability %	% of Hours BESS was available to provide support to a grid outage divided by Total In-Service Minutes for Year

Residential Behind the Meter Battery Energy Storage System – Performance Data for 2025

The breakdown of residential behind-the-meter Battery Energy Storage System (BTM BESS) performance data for units connected to Hydro One Networks Inc.'s (Hydro One) distribution system for the period, January to December 2025, is provided below.

BTM BESS Performance Reporting - 2025					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Almonte TS	9.00	0.09	9.07	7.27	80%
Arnprior TS	5.00	0.05	72.40	72.40	100%
Aylmer TS	1.00	0.01	7.33	7.33	100%
Beaverton TS	1.00	0.01	6.83	6.83	100%
Brant TS	2.00	0.02	33.75	33.75	100%
Buchanan TS	2.00	0.02	6.90	6.90	100%
Centralia TS	5.00	0.05	42.18	29.38	70%
Cobden TS	14.00	0.14	910.22	842.78	93%
Constance DS	2.00	0.02	18.53	18.53	100%
Crosby TS	5.00	0.05	346.95	313.62	90%
Des Joachims DS	1.00	0.01	16.98	16.98	100%
Dunnville TS	2.00	0.02	33.68	33.68	100%
Goderich TS	1.00	0.01	19.43	19.43	100%
Havelock TS	6.00	0.06	926.43	708.18	76%
Herridge Lake DS	3.00	0.03	39.05	39.05	100%
Hinchinbrooke DS	5.00	0.05	242.60	221.28	91%
Ingersoll TS	14.00	0.14	310.98	310.98	100%
Kleinburg TS	1.00	0.01	48.62	42.35	87%

BTM BESS Performance Reporting - 2025					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Larchwood TS	4.00	0.04	4.73	4.73	100%
Lindsay TS	5.00	0.05	1699.5	951.72	56%
Martindale TS	6.00	0.06	230.25	214.17	93%
Mattawa DS	1.00	0.01	116.53	116.52	100%
Meaford TS	2.00	0.02	8.62	8.62	100%
Minden TS	28.00	0.28	3000.47	2385.60	80%
Minden TS	2.00	0.02	6.78	6.78	100%
Murillo DS	3.00	0.03	35.97	34.72	97%
Muskoka TS	28.00	0.28	1413.38	1290.47	91%
Muskoka TS	1.00	0.01	69.55	67.80	97%
Orangeville TS	2.00	0.02	41.05	41.05	100%
Otonabee TS	4.00	0.04	295.98	166.73	56%
Parry Sound TS	1.00	0.01	67.78	67.78	100%
Port Arthur TS	4.00	0.04	7.32	7.32	100%
Rockland East DS	1.00	0.01	3.90	3.90	100%
Seaforth TS	1.00	0.01	11.20	11.20	100%
Shabaqua DS	1.00	0.01	37.72	37.72	100%
Sharbot DS	3.00	0.03	42.52	40.27	95%
Smiths Falls TS	63.00	0.63	1306.40	1207.18	92%
Stewartville TS	1.00	0.01	29.55	29.55	100%
Tillsonburg TS	24.00	0.24	371.17	371.15	100%
Trout Lake TS	72.00	0.72	4974.23	4619.90	93%
Trout Lake TS	1.00	0.01	6.35	6.35	100%

BTM BESS Performance Reporting - 2025					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Wallace TS	47.00	0.47	3499.55	3050.37	87%
Wharncliffe DS	1.00	0.01	18.10	18.10	100%
Whitefish DS	11.00	0.11	250.72	244.82	98%
Wolverton DS	3.00	0.03	9.95	9.95	100%

Reference Table	
Name	**Description**
Station Name	Network connection downstream of the first level connection to Hydro One Transmission circuit
Count	Number of BESS Units connected to Station
Capacity	Total MW Capacity of BESS Units at Station
Total Customer Outage Time	Total annual customer x hours of grid outage time
Total Outage Duration Avoided by BESS	Total annual grid outage time (customer x hours) serviced by BESS to reduce customer outage time
% Outage hrs Mitigated	Total customer x hours of outage backed up by BESS divided by Total Customer Outage Time

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Grid Scale Front of the Meter Battery Energy Storage System – Performance Data for 2025

The breakdown of Hydro One Networks Inc. (Hydro One) owned grid scale front-of-the-meter Battery Energy Storage Systems (FTM BESS) connected to Hydro One's distribution system as of December 31, 2025, is as follows:

Hydro One FTM BESS Performance Data - 2025						
Station Name	**Year**	**# of Grid Outage Events**	**Total Grid Outage (Hours) = (A)**	**BESS Operation (Hours) = (B)**	**% Outage Hrs Mitigated = (B) / (A)**	**Availability %**
Nakina DS (Aroland BESS)	2025	13	34.0	6.2	18%	90%

REFERENCE TABLE	
Name	**Description**
Station Name	Hydro One Station to which FTM BESS is connected
# of Grid Outage Events	Number of annual grid outages experienced by the BESS
Grid Outage	Total annual grid outage time (hours) experienced by BESS
BESS Operation	Total annual grid outage time (hours) serviced by BESS to minimize customer outage time
% Outage Hrs Mitigated	BESS Operation Time divided by Grid Outage Time
Availability %	% of Hours BESS was available to provide support to a grid outage divided by Total In-Service Minutes for Year

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D-SS-05	Distribution Automation & Sectionalization Program
Primary Trigger:	Improving restoration time
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	39.3	45.1	57.0	62.1	67.3	270.8
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This investment targets improving restoration time of distribution feeders by installing remote operable devices with Supervisory Control and Data Acquisition (SCADA) capabilities to remotely identify the location of a fault, sectionalize the feeders and enable load transfer to facilitate faster customer power restoration. This investment will also enable fault detection on additional feeders by installing and utilizing Communicating Fault Circuit Indicators (CFCI) sensors.

There are no planned capital expenditures for Orillia Rate Zone (RZ) or Peterborough RZ.

1.0 INVESTMENT NEED

Hydro One customers experienced average annual System Average Interruption Duration Index (SAIDI) of approximately 22 hours from 2021 to 2025, including all major weather events. Extended outages disrupt residential customers, businesses and industrial operations. Improving the speed with which Hydro One can locate faults, isolate damaged sections and restore unaffected customers helps mitigate the impacts of these outages and improves restoration time.

Where a feeder is not equipped with remote monitoring and remote operable devices, restoration generally requires field crews to first patrol the feeder to determine the cause of the outage and identify the faulted section and then travel to manually operated device(s) before the fault can be isolated or load can be transferred. These sequential activities increase the duration of the outage for all customers supplied by the feeder, including the customer located on the sections that are not directly affected by the fault.

Hydro One operates 3,374 distribution feeders, comprising 703 sub-transmission feeders (M-class) and 2,671 distribution level feeders (F-class). M-class feeders originate from Transmission Stations at the 27.6kV or 44kV level and generally supply one or more distribution stations, large directly connected customers and, in some cases, embedded local distribution companies. As a result of their upstream position within the distribution system, an interruption on an M-class feeder can affect customers supplied directly from the feeder as well as customers supplied through downstream distribution stations. M-class feeders therefore represent a relatively small but significant portion of Hydro One's Distribution feeder population and are considered a higher priority for enabling remotely controlled switching capabilities.

Over the past seven years Hydro One has installed remote operable devices on 42% of M-class feeders. These devices enable significant operational benefits. For example, in 2025 approximately 260 remote operations enabled Hydro One to isolate faulted feeder sections, transfer load where alternative supply was available, and restore customers on unaffected sections more quickly, thereby reducing outage duration.

The 2028-2032 investment would expand this remote operational capability to additional M-class feeders for which remote sectionalization or load transfers can improve restoration time. Hydro One plans to install approximately 1,150 remote operable devices and increase remote operational capability to 90% of M-class feeders. The proposed investment would increase sectionalization and remote operational capability coverage from approximately 10% of Hydro One's total feeder population today to 20% by the end of the 2028-2032 planning period. The program therefore represents a targeted and prioritized expansion across a critical portion of the distribution system.

F-class feeders originate from distribution stations, generally operate at 27.6kV or below, and primarily supply more localized distribution areas. Certain F-class feeders may also serve critical or high-impact loads and may warrant remote automation based on their individual characteristics. However, prioritizing eligible M-class feeders during the 2028-2032 period allows Hydro One to direct the proposed investment toward feeders expected to provide the greatest overall restoration and operational benefit while maintaining an appropriate balance between system performance and costs.

Phase 2 Customer Engagement results support continued investment in installation of remote operable devices to manage the impact of severe weather and improve restoration time. More than 50% of participating customers supported the planned level of installing 1,200 devices and more than 20% supported a higher level of installing 1,650 remote operable devices. This was presented in Phase 2 Customer Engagement Survey Results Report: SPF Section 1.6, Attachment 1, p. 550-552. The proposed scope of installing approximately 1,150 devices is generally consistent with the planned level tested through customer engagement and reflects Hydro One's assessment of the eligible M-class feeder population.

Remote operable devices are integrated with Hydro One's SCADA and Distribution Management System (DMS). Following a fault, system operators can use device status and fault indications to identify the affected section, remotely open devices to isolate the fault, and restore remaining customers that are on the healthy section of the feeder. Where a suitable feeder tie and sufficient capacity are available, operators can also remotely transfer load to an alternative supply by remotely closing the tie device.

Table 1 provides examples[1] of customer restorations in 2025 utilizing remote operable devices and illustrates the benefits in scenarios where load transfer to alternative supply is available and restoration can fully leverage remote operable capabilities. The column 'Actual CMI (utilizing remote operation)' indicates the actual impact of the event on customers and highlights the outage reduction impact due to remote operational capabilities. The column 'CMI (no remote operation)' indicates how long the outage event lasted, and the total time all impacted customers would have been without power in absence of utilizing remote operational capabilities.

Table 1 - Examples of 2025 Restorations using Remote Operable Devices

Date of Event	Impacted Feeder	Total Number of Customers Impacted	Number of customers Restored Utilizing Remote Operable Devices	CMI (no remote operation)	Actual CMI (utilizing remote operation)	Percent CMI Improved
12/29/2025	Orillia TS M7;	5,010	5,010	1,407,810	100,200	93%
12/29/2025	Beaverton TS M26;	4,828	4,828	984,912	91,732	91%
7/1/2025	Timmins TS M10;	2,953	2,953	203,757	115,167	43%
12/26/2025	Longwood TS M23;	2,645	1,633	600,415	290,145	52%
12/24/2025	Centralia TS M2;	3,273	1,050	1,466,304	1,315,104	10%
12/27/2025	Norfolk TS M4;	747	635	135,954	25,464	81%
12/29/2025	Dunnville TS M1;	682	635	50,468	10,463	79%
8/8/2025	Hearst TS M1;	451	337	141,163	49,836	65%
12/3/2025	Jarvis TS M6;	703	336	125,134	77,758	38%
12/28/2025	Tillsonburg TS M1;	445	192	123,265	104,065	16%

Table 1 shows that many of the customers impacted by the events experienced shorter outage durations because of remote operable devices that were used for sectionalization and load transfer. Across the examples provided, CMI improvements ranged from 10% to 93%, with an average improvement of 57%. The magnitude of reliability improvements is

[1] These examples represent outages with total restoration time of less than eight hours. For longer outages, manual switching could have been utilized and could skew the CMI values.

dependent on the unique circumstances of each fault event, including factors such as feeder configuration, location of fault, and availability of tie points.

The following staged illustration further demonstrates the benefit of adding remote operable devices, utilizing the event of Dec 27, 2025, on the Norfolk TS M4 feeder as an example. The stages show the configuration of the feeder under ordinary and fault operating conditions, both in the prior configuration before the installation of remote operable devices and in its current configuration with remote operable devices.

Stage A: Prior configuration before installation of remote operable devices – No Fault Condition

Figure 1 presents the configuration of the Norfolk TS M4 before installation of any remote operable devices. At this time, a recloser existed which could isolate faults further than 5km from the feeder head, however, there were no remote operable capabilities with this device nor with the adjacent feeder tie-points.

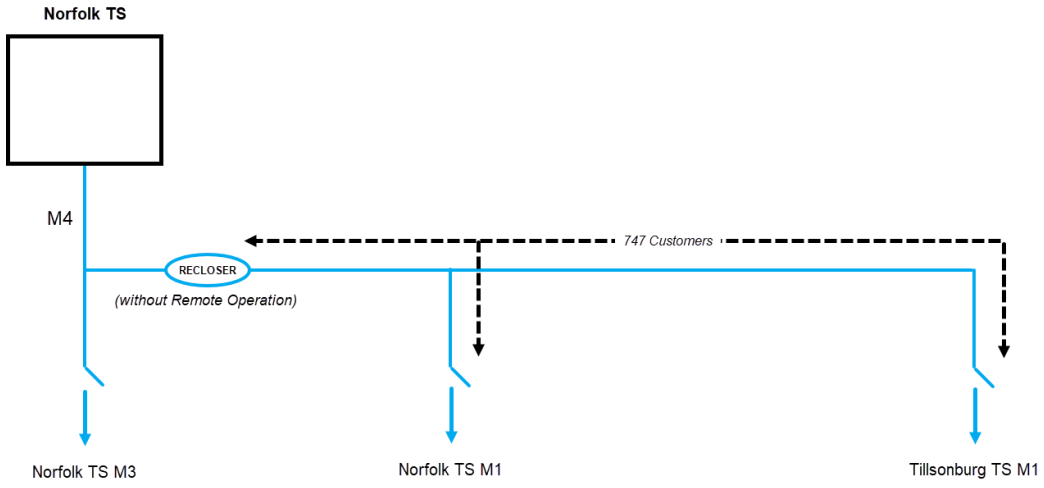


Figure 1: Prior configuration before installation of remote operable devices- No Fault Condition

Stage B: Prior configuration before installation of remote operable devices – Fault Condition

In the event of a fault downstream of the recloser, the recloser would operate causing an outage on downstream customers, maintaining power to the remaining portion of the M4 feeder upstream of the recloser. As there was no SCADA information available along this feeder, a field crew would need to be dispatched to patrol the feeder downstream of the recloser and inform the operator about the location of the fault and potential restoration activities required to clear it. Since there were no remote capabilities on this recloser, nor any means of remote fault detection/sectionalization between the recloser and tie-points, all customers downstream of the recloser would have remained without power until responding crews arrived on site and corrected the cause of the outage or performed manual switching to restore a portion of the feeder. Figure 2 shows the Norfolk M4 configuration and the number of customers that would have been without power in the event of a fault like that which occurred on December 27th, 2025.

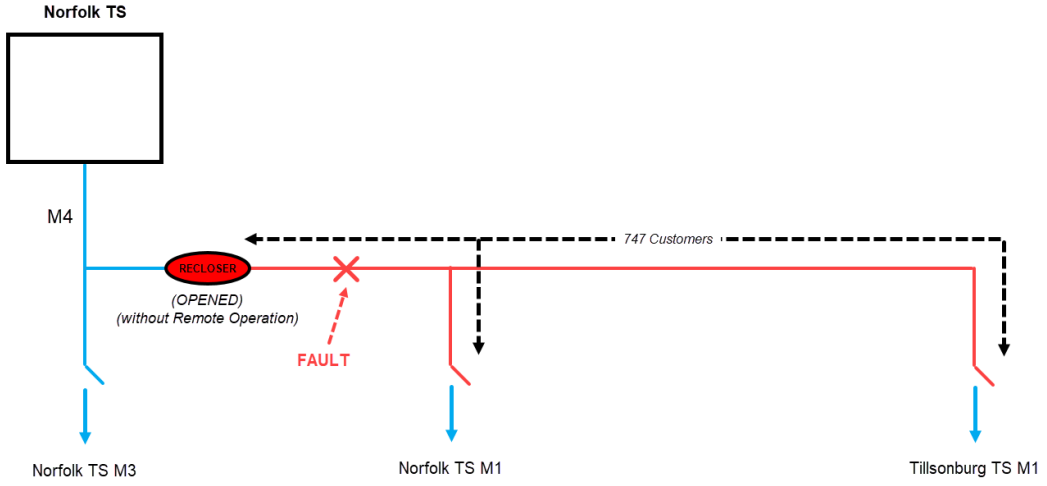


Figure 2: Prior Configuration Before Installation of Remote Operable Devices- Fault Condition

Stage C: Current configuration after installation of remote operable devices – No Fault Condition

By 2024, remote operable devices were installed along the feeder for additional sectionalization as well as at feeder tie-points, and remote operation was enabled at the recloser as well. Figure 3 presents the configuration of Norfolk M4 after installation of remote operable devices.

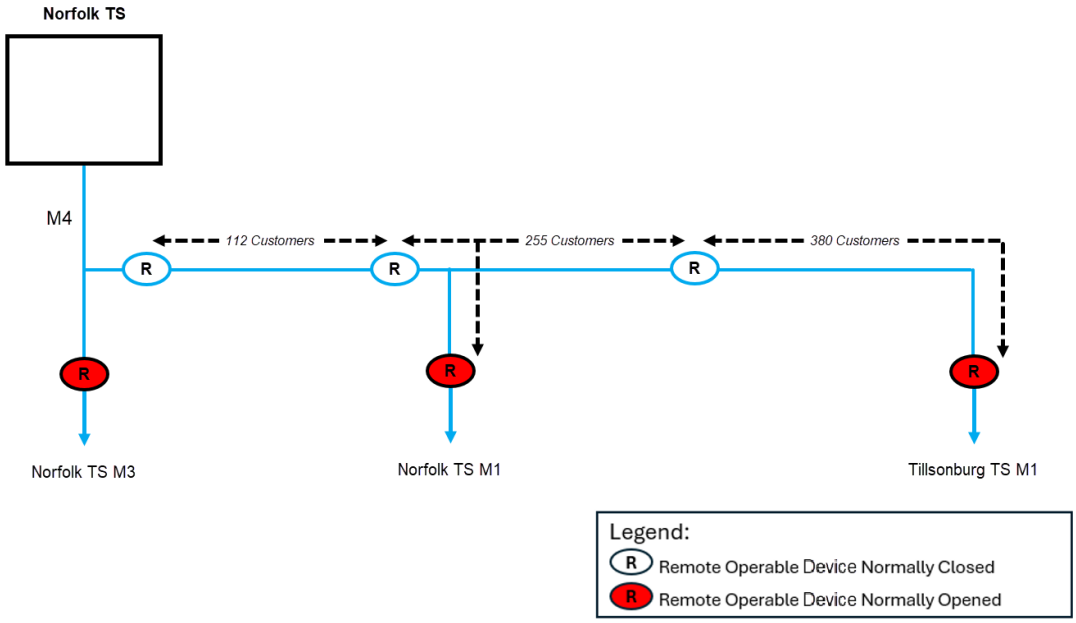


Figure 3: Current Configuration after Installation of Remote Operable Devices- No Fault Condition

Stage D: Current configuration after installation of remote operable devices – Fault Condition

In the event of a fault between the recloser and the next downstream remote operable device, SCADA information and remote operation capabilities from these devices are utilized by operators to isolate the faulted section of the feeder and restore power to all remaining customers by transferring load to Tillsonburg TS M1. Figure 4 presents configuration of Norfolk M4 and affected customers after remote sectionalization and transfer of load to Tillsonburg M1.

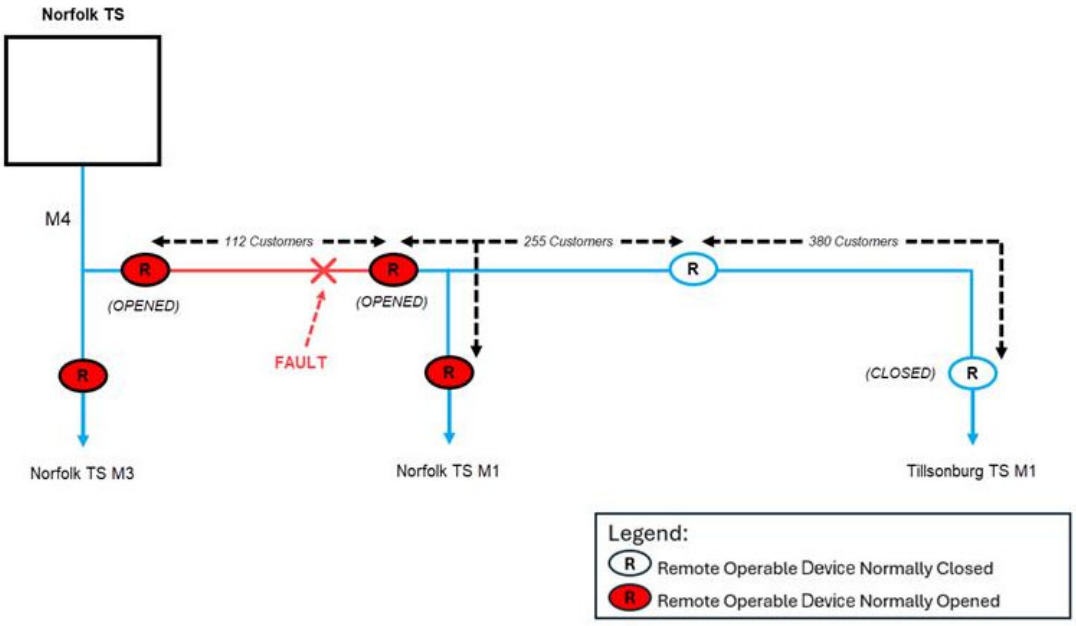


Figure 4: Current Configuration After Installation of Remote Operable Devices- Fault Condition

This example demonstrates the material reduction in CMI by utilizing remote operable devices installed along the feeder to sectionalize the faulted location and at tie-points to enable remote load transfer. In this example, two benefits contributed to the improved restoration time compared to the original configuration: 1) 85% of customers downstream of the recloser were restored remotely, significantly reducing the extent of the outage for these customers and improving CMI, and 2) responding crews had a focused area of the feeder to patrol, reducing the overall duration of the outage for remaining customers.

The second component of the investment addresses feeders that have no SCADA-based fault indication. Hydro One has installed CFCIs on more than 50% of F-class feeders, particularly at feeder heads. When a fault occurs, the CFCI raises an alarm in DMS informing operators about the presence of a fault and provides a fault current value that assists in identifying the approximate distance of the fault from the CFCI unit. Field crews can then be directed to a much narrower search area rather than patrolling the full feeder length before restoration and repair activities can begin.

The proposed investment will install approximately 5,100 CFCI units on more than 1,000 feeders that currently have no fault-indication capability. These units will be installed at the feeder head and at the beginning of some laterals, when warranted by feeder length, branching, and customer count.

This investment is part of grid modernization efforts. The expenditure converts manual fault-location into remotely monitored fault-location and enables remotely controlled functions integrated with the DMS. The primary benefit of the investment is reduction in outage duration through faster fault location, sectionalization and restoration.

In addition to improved restoration time and operational benefits, the installation of remotely operable devices provides distribution system resiliency benefits. In developing this investment, Hydro One considered historical storm and outage data to ensure resiliency benefits were reviewed alongside other priorities such as reduction of restoration time. Refer to DSP Section 3.3, subsection 3.3.2.5.2, and DSP Section 3.6, subsection 3.6.6.3 for further information.

2.0 INVESTMENT DESCRIPTION

This investment focuses on installation of remote operable devices on M-class feeders increasing remote operational capability coverage from approximately 10% of Hydro One's total feeder population today to 20% by the end of the 2028-2032 planning period. The expenditure will allow Hydro One to locate and respond to outages faster, remotely sectionalize feeders to restore as many customers as possible, and improve remote load transfer capabilities. This investment will enable Hydro One to reduce the duration of outages on more than 300 additional M-class feeders, extending the operational benefit and outage time reduction to 90% of M-class feeders. Further, by adding CFCI units on more than 1,000 feeders that currently lack SCADA capabilities, system operators can utilize the SCADA information and reduce the time it takes to locate the faulted section on these feeders.

This investment will improve restoration time using the following solutions:

- Deployment of remote operable devices that can be remotely controlled to provide isolation and sectionalization;

- Installing remote operable devices at existing tie points to enable faster load transfers; and
- Installation of CFCIs, which will identify the fault location to system operators to enable faster restoration by field personnel.

This investment will install remote operable devices as sectionalizing devices and at available tie points to enable remote load transfers. Each feeder will be studied in detail to determine the optimum location for installation of the remote operable devices. The location of devices is evaluated based on historical outage locations, exposure of overhead line sections based on their length, and location of the load centers along the feeders. Furthermore, the location of these devices is impacted by accessibility to enable future maintenance and replacement. Longer feeders on average could benefit from installation of four remote operable devices per feeder, whereas shorter feeders on average could benefit from one or two devices per feeder depending on the availability of tie points. Long feeders typically support two load centers and depending on the geographical layout of the feeder, approximately two devices could be installed after each of the load centers to provide sectionalization benefit: one remote operable device at the available tie location, and one device upstream of the load centers to enable transfer of the load centers to the alternative supply.

Hydro One has installed CFCIs on approximately 50% of F-class feeders, particularly at feeder heads. This investment includes installation of approximately 5,100 additional CFCI units on more than 1,000 feeders that currently have no fault indicators or SCADA devices, bringing SCADA visibility to all F-class feeders. When a fault occurs, the fault information is communicated by these CFCIs to Hydro One’s control center allowing operators to determine the presence and approximate fault location and dispatch field crews directly to the site of the fault; this reduces the time it takes to identify fault location before restoration can begin.

At least three CFCI units are required per feeder, one on each phase. As part of this program, approximately 1,000 units are planned to be installed annually, covering more than 200 feeders per year. The priority is to install one set of CFCIs at the feeder head for

feeders that do not have any existing SCADA devices. Feeders with long lengths and multiple laterals with high customer count could receive additional CFCIs along the feeder, especially at the beginning of the main laterals to further improve fault detection along the main line and populated branches.

Installation of CFCI units at the feeder head for feeders that currently lack SCADA or other monitoring devices also provides the secondary benefit of load visibility on these feeders. Knowing the continuous feeder loading level enables better load transfer and outage plans and minimizes the impact of planned outage for customers supplied by these feeders. Further, continuous load visibility supports capacity planning of the distribution system.

3.0 OUTCOMES

This investment will have the following outcomes:

- Reducing outage times by identifying where a fault has occurred and directing crews to the location of the fault through SCADA 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 sectionalization and load transfers from the grid control room to remotely restore as many customers as possible.

Overall, this investment will enable Hydro One to reduce the duration of outages on 90% of M-class feeders. Further, by adding CFCI units on more than 1000 feeders, system operators can utilize SCADA information to reduce the time it takes to locate the faulted section.

3.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the investment in accordance with the OEB's RRF:

Table 2 - Outcome Summary

Customer Focus	• Reduce the duration of electricity supply outages to customers.
Operational Effectiveness	• Improved restoration time through faster location, isolation and restoration of power outages. • Improved operational effectiveness through enablement of remote devices to facilitate load transfers.

4.0 EXPENDITURE PLAN

Cost estimates are based on the average historical unit cost for this investment. Longer feeders on average could benefit from installation of four remote operable devices per feeder, whereas shorter feeders on average could benefit from one or two devices per feeder depending on availability of a tie point.

The main factors impacting the cost of the investment include:

- The equipment cost of remote operable devices;
- Associated equipment modifications required to meet Hydro One Standards, such as required clearances;
- Availability of the 120V power supply for the controller function and availability of space for installation of a service transformer;
- Wireless signal availability and strength, which impacts location of device installation or the need for additional equipment such as local antennas.

Table 3 summarizes Hydro One's planned number of remote operable device installations per year.

Table 3 - Hydro One - Remote Operable Unit Installation Plan

	2028	2029	2030	2031	2032	Total 28-32
Number of Remote Operable Devices	165	190	245	265	290	1,155

Cost estimates for CFCIs are based on average historical unit costs. The factors influencing the cost of the investment include:

- The equipment cost;
- The cost to program and connect new units to DMS;

- Wireless signal availability and strength, which impacts location of device installation and the need for additional telecom equipment.

Table 4 summarizes Hydro One's planned CFCI installations per year.

Table 4 - Hydro One - CFCI Plan

	2028	2029	2030	2031	2032	Total 28-32
Number of CFCI units	1,024	1,024	1,024	1,024	1,024	5,120

Table 5 below summarizes Hydro One's aggregate planned and forecast net capital expenditures for the 2023-2027 rate period and the forecast net capital expenditures for the 2028-2032 planning period. There are no planned, annual or forecasted net capital expenditures for Orillia RZ or Peterborough RZ. The costs presented in the investment summary are derived from historical and estimated unit costs.

Table 5 - Hydro One - Investment Expenditures

$M	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	217.2	124.0	44.1	50.7	64.2	69.9	75.9	304.8
Less Removals	25.2	13.0	4.8	5.5	7.2	7.9	8.6	34.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Net Capital Expenditures	**192.0**	**111.0**	**39.3**	**45.1**	**57.0**	**62.1**	**67.3**	**270.8**

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be $111M versus a planned expenditure of $192M, resulting in a variance of $81M or 42.2%. The variance reflects lower expenditures and was driven primarily by reprioritization in response to emerging system needs, partially offset by higher than expected per-unit costs. Actual expenditures differed from plan due to changes in work

[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures

volumes and timing. In addition, investment costs evolved over the 2023-2027 period because of detailed engineering and unexpected cost increases for equipment such as Remote Operable Load Break Switches, and Remote Operable Vacuum Switch or Reclosers. As outlined in SPF Section 1.8, Subsection 1.8.3, these cost increases reflect broader utility-sector market conditions.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are $270.8M. On a volume basis, for the remote operable device installation, the forecast includes approximately 1,150 units over the 2028-2032 period, compared to the 2023-2027 forecasted expenditure that includes installation of 400 units over the period plus 100 units that are designed and procured in advance for installation in 2028. The investment is intended to address a larger volume of remote operable device installations to extend operational flexibility and improve restoration time on 90% of M-class feeders. For the CFCI installation, the volume is planned to stay consistent to the historical period.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: DO NOTHING (REJECTED)

Under this alternative Hydro One would not install any new remote operable devices or CFCIs and customers would not benefit from a reduction in outage duration. This would be in contrast with the desire of the majority of Hydro One customers to manage the impact of severe weather and improve restoration time through installation of remote operable devices (as demonstrated in Phase 2 Customer Engagement Survey Results Report in SPF Section 1.6, Attachment 1, p. 550-552). This alternative is therefore rejected because it is not aligned with customer preference.

ALTERNATIVE 2: REDUCE THE NUMBER OF REMOTE OPERABLE DEVICE INSTALLATIONS TO 750 UNITS, AND INSTALL 5,000 CFCI UNITS (REJECTED)

This alternative would continue the investment at a slower pace, resulting in restoration time improvement and remote operation for a total of 60% of M-class feeders. Customers supplied by the remaining feeders would not benefit from reduction in outage duration.

This alternative approach would install sectionalizing devices, improve feeder transfer capability, and provide grid control room operators with additional information about the current state of the system on 60% of M-class feeders only. CFCIs represent less than 10% of the total proposed investment for this alternative. This alternative is rejected because it does not fully capitalize on the opportunity to cost-effectively reduce the impact or outage duration for customers and is not fully aligned with customer preference.

ALTERNATIVE 3: INCREASE THE NUMBER OF REMOTE OPERABLE DEVICE INSTALLATIONS TO 1,600 UNITS, AND INSTALL 5,000 CFCI UNITS (REJECTED)

This alternative would continue the investment at a higher pace, resulting in installation of remote operable devices on 90% of M-class feeders as well as 5% of F-class feeders. CFCIs represent less than 10% of the total proposed investment for this alternative. This alternative is rejected because the increased cost is not justified by the incremental benefit derived from the additional feeders addressed which serve and impact fewer downstream customers.

ALTERNATIVE 4: INSTALL APPROXIMATELY 1,150 REMOTE OPERABLE DEVICES AND 5,000 CFCI UNITS (RECOMMENDED)

This alternative involves investments at the recommended pace, resulting in restoration time improvement and remote operation for a total of 90% of M-class feeders that can benefit from remote operable devices. This level of investment will enable a larger group of feeders to be included and as a result more customers will benefit from the reduction in outage duration. Phase 2 of the Customer Engagement (SPF Section 1.6, Attachment 1, p. 550-552) demonstrated strong support for investments to improve restoration time and manage the impact of severe weather by installation of remote operable devices. This alternative is recommended for cost effectiveness and to reduce the impact of outages and improve restoration time for customers in alignment with their preference.

6.0 EXECUTION RISK AND MITIGATION

Table 6 below outlines the main risks that can impact the execution of the investment and their associated mitigation strategy.

Table 6 - Risks and Mitigations

Execution Risk	Risk Mitigation
Access to the site installation location depending on the season. Factors such as half load restrictions on some roads, or level of snow on the ground can impact the execution timelines.	Managed through extensive collaborative and cross-functional planning, and scheduling across the relevant lines of business.
Outage availability and duration for installation of remote operable devices, as new device installation would require a planned outage on the feeder	Managed through extensive 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. Also to limit the impact of planned outages, multiple crews have been dispatched for installation of multiple devices on the same feeder in parallel.
Supply chain procurement and availability of devices for installation	Frequent communication between Supply Chain and vendors on material lead times, combined with ability to pre-order known long lead materials will improve the likelihood that critical components are available when required.

D-SS-06	POWER QUALITY AND STRAY VOLTAGE
Primary Trigger:	Power Quality
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	6.3	7.0	10.1	6.9	7.1	37.4
Orillia RZ	0.06	0.06	0.06	Embedded in Hydro One Networks		
Peterborough RZ	0.06	0.06	0.06			

Summary:

This non-discretionary investment involves the investigation and resolution of power quality and stray voltage issues that adversely impact customer experience and could cause a safety risk. Resolving power quality and stray voltage issues is required under the OEB's Distribution System Code (DSC). Power quality and stray voltage issues are typically identified through customer complaints.

1.0 INVESTMENT NEED

This non-discretionary demand investment is needed to respond to customer complaints resulting from power quality and stray voltage issues. The investment includes investigating and performing the necessary corrective work as required in compliance with the OEB's DSC, Sections 4.1 (Quality of Supply) and 4.7 (Farm Stray Voltage).

Power quality issues arise when the voltage, frequency, or phase balance of the supply does not conform to the specifications required by the DSC. Stray voltage is a specific type of power quality issue where a small electrical potential between two conductive surfaces exists. It is the by-product of the normal delivery and use of electricity and if the voltage level is high enough, it may result in electric shock and, for farm customers, may affect livestock behavior and health.

2.0 INVESTMENT DESCRIPTION

This demand program encompasses the capital costs associated with the investigation and resolution of the following conditions:

- power quality including high voltage, low voltage, phase imbalance, flicker, harmonics, etc.;
- farm or residential stray voltage; and
- neutral-to-earth voltage (NEV) exceeding limits.

Hydro One performs several measures to address power quality and stray voltage issues, including:

- examination of the integrity of neutral and grounding systems;
- defect correction;
- installation of additional grounding rods or neutral isolators;
- balancing loads; and
- upgrading conductors.

Upon investigation, if the power quality or stray voltage issue requires more extensive upgrades, a planned solution may be required to achieve compliance and resolve safety concerns, such as single-phase to three-phase conversion. Planned projects are

managed in accordance with the project execution methodology described in DSP Section 3.10.

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 DSP Section 3.11, 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.

3.0 OUTCOMES

The Power Quality and Stray Voltage program will:

- mitigate safety risks associated with power quality and stray voltage issues, and
- support compliance with DSC sections 4.1 Quality of Supply and 4.7 Farm Stray Voltage.

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the investment in accordance with the OEB's 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 sections 4.1 (Quality of Supply) and 4.7 (Farm Stray Voltage) of the Distribution System Code.

4.0 EXPENDITURE PLAN

Tables 2, 3, and 4 summarize Hydro One's, Orillia RZ's, and Peterborough RZ's planned and forecast net capital expenditures for the 2023-2027 rate period and forecast net capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	23.7	50.8	7.2	7.9	11.4	7.9	8.0	42.4
Less Removals	2.8	5.7	0.9	0.9	1.3	0.9	1.0	5.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**20.8**	**45.0**	**6.3**	**7.0**	**10.1**	**6.9**	**7.1**	**37.4**

Table 3 - Orillia RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	0.22	0.08	0.08	0.08	Embedded in Hydro One Networks		
Less Removals		0.04	0.01	0.01	0.01			
Less Capital Contributions		0.00	0.00	0.00	0.00			
Net Capital Expenditures		**0.19**	**0.06**	**0.06**	**0.06**			

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditures and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Table 4 - Peterborough RZ - Investment Expenditures

($M)	Plan 23-27	Act/Fcst 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	0.14	0.08	0.08	0.08	Embedded in Hydro One Networks		
Less Removals		0.02	0.01	0.01	0.01			
Less Capital Contributions		0.12	0.06	0.06	0.06			
Net Capital Expenditures		**0.06**	**0.06**	**0.06**	**0.06**			

The factors affecting the cost of the investment include:

- the amount of power quality and stray voltage issues that arise each year;
- the complexity of the investigation; and
- the scope of the work required to fix the issue.

2023-2027 EXPENDITURES

Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be $24.2M higher than planned, primarily due to higher-than-expected work volumes, more severe power quality and stray voltage cases, and material cost escalations as described in SPF 1.8, Section 1.8.3. Increased work volumes were mainly driven by scope complexity arising where standard remediation measures, such as grounding improvements or installation of neutral isolators, were not sufficient to achieve compliance or address safety concerns. For example, the Rutherglen DS project was initiated in response to significant load growth resulting in high single-phase loading and elevated NEV on a lateral line already being supported by multiple voltage regulators. As a result, a project was released to convert a 10 km section to three-phase service to balance load and resolve the issue. Relative to plan, program scope shifted toward more complex stray voltage investigations and larger corrective interventions at specific locations. These expenditures were primarily driven by work identified and released during the rate period.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are based on historical program expenditures and known work volumes. The only planned project is the

Kimberley DS transformer replacement in 2030 which represents approximately $4.0M of the total investment. Additional planned project expenditures have not been included in the 2028-2032 plan as no further projects are currently known or sufficiently scoped for inclusion. Orillia RZ and Peterborough RZ are included within Hydro One's forecast beginning in 2031 in line with the spending levels from 2028-2030.

5.0 ALTERNATIVES

No alternatives are considered, since this investment is non-discretionary; failure to address power quality and stray voltage complaints violates the DSC and may result in unacceptable system performance.

Where investigation results in a planned remediation, alternatives are considered. For the Kimberley DS transformer replacement, the alternatives considered included:

- Installation of Regulators on All Feeders (rejected): This alternative was rejected because there is insufficient space to install regulators upstream of customers near the station, who are most affected by upstream voltage fluctuations. As a result, the alternative would not have adequately addressed the voltage concerns for these customers.
- Utilize the Existing Off-Load Tap Charger (rejected): While this alternative presents a feasible short-term solution, it was rejected because it introduces reliability impacts by requiring a minimum of two planned outages annually for maintenance.
- Replace Transformers (recommended): This alternative is the only practical long-term remediation available to ensure reliability and allows for the addition of voltage regulation.

6.0 EXECUTION RISK AND MITIGATION

Execution risk is mainly due to the non-discretionary nature of the investment and unknowns related to the complexity of remediation required. Because power quality and stray voltage scope is non-discretionary, it must be prioritized, which can result in resourcing risks. When work volumes exceed forecast, resources must be available to complete the scope. This risk is mitigated through Hydro One's use of multiple resource types, in particular the availability of casual resources which can be onboarded and

offboarded quickly to address peak workloads. The scope and cost of work identified through the investigation process can exceed forecasts. Increased complexity may lead to higher costs and longer execution schedules. Hydro One mitigates this risk through detailed project planning and risk management processes to identify and manage site-specific challenges. Also, project execution strategies are tailored to local conditions, with ongoing coordination among internal teams, contractors, municipalities, customers, and other stakeholders. Refer to DSP Section 3.10 for additional details on project management and execution practices.

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D-SS-07	DER HOSTING CAPACITY
Primary Trigger:	Customer Requests
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	3.7	17.0	16.6	16.9	17.2	71.4
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

In accordance with the OEB's Framework for Energy Innovation (FEI) and in support of provincial policy objectives related to Distributed Energy Resource (DER) adoption, this investment will upgrade capacity-constrained distribution feeders that currently limit customers' ability to connect new micro-embedded generation. The investment is expected to remove hosting capacity constraints on approximately 190 feeders, creating more than 43MW of additional micro-embedded generation hosting capacity and enabling an estimated 3,600 to 4,300 additional customer connections. By reducing barriers to adoption, the investment will support customer participation in provincial energy programs, maintain reliable service, and position Hydro One's distribution system to accommodate future growth.

There are no planned, annual or forecasted net capital expenditures for Orillia RZ or Peterborough RZ.

1.0 OVERVIEW

The investments in this ISD respond to the OEB's expectation, as set out in the FEI, that local distribution companies should "prepare for DER impacts on their systems, including integrating these resources cost-effectively, while maintaining reliable service for their customers."[1] As described in DSP Section 3.4, Hydro One plans to address distribution system capacity constraints over the 2028-2032 period to expand opportunities to connect micro-embedded generation resources. These investments will increase DER hosting capacity, facilitate customer participation in provincial energy programs, and support the continued growth of DERs across Hydro One's service territory.

This new program is responsive to the OEB's expectations as set out in the FEI report:

> The OEB expects distributors to plan, design, and operate their systems in a way that accounts for the anticipated impacts of DERs – informed by best available forecasts of DER adoption in each distributors' service area – to ensure that distribution customers continue to receive reliable distribution service and that service quality is not degraded by DER integration. Doing so will also ensure that limitations of the distribution system do not pose an undue barrier to customers exercising their choice to adopt DERs. Customers would still be expected to pay for connection costs that are specific to their DER (for example, protection systems that are only required due to the existence of that facility). However, a distributor may propose system investments that enable DER integration, where the investments are not necessarily attributable to a given customer's facility or group of facilities and are justifiable in light of expected DER adoption and the benefits that may be conferred.

Consistent with the OEB's guidance, these investments will expand micro-embedded generation hosting capacity on constrained feeders, enable additional customer connections, support participation in provincial DER programs, and facilitate continued growth in DER adoption across Hydro One's service territory.

[1] *Framework for Energy Innovation: Setting a Path Forward for DER Integration*, OEB, January 2023, p. 3. [FEI]

2.0 INVESTMENT NEED

Despite Hydro One's historical efforts to increase DER connection capacity on the distribution system as described in DSP Section 3.4, there remain numerous constrained feeders that cannot accommodate additional DER connections. As of December 31, 2025, approximately 130 feeders were unable to accommodate additional micro-embedded generation connections. Without further investment, these limitations are expected to become increasingly prevalent as micro-embedded generation adoption continues. If each feeder were to receive an average of three micro-embedded generation connection applications, which is aligned with the total forecasted micro-embedded generation volumes, an additional 440 feeders could become constrained.

The investments in this program will increase micro-embedded generation hosting capacity by addressing feeders that are currently constrained, as well as feeders forecast to become constrained over the 2028-2032 period. The population of constrained feeders is expected to evolve over time based on factors such as micro-embedded generation adoption rates and changes in distribution system configuration. Accordingly, the specific feeders requiring upgrades, and the associated costs, will depend on system conditions at the time the work is undertaken.

Based on historical unit costs, the proposed expenditures are expected to be sufficient to address the approximately 130 feeders that are currently unable to accommodate additional micro-embedded generation connections, as well as approximately 60 additional feeders forecast to become constrained during the planning period.

Collectively, these investments will address constraints on approximately 190 feeders, creating more than 43MW of additional micro-embedded generation hosting capacity and enabling approximately 3,600 to 4,300 additional customer connections. In doing so, they will expand opportunities for customers to participate in DER programs, support continued growth in DER adoption across Hydro One's service territory, and maintain the safe and reliable operation of the distribution system.

3.0 INVESTMENT DESCRIPTION

In developing this investment, Hydro One assessed a sample of the population of feeders that currently have no available capacity to connect new micro-embedded generation. The assessment determined that these constrained feeders generally require similar upgrades and enhancements to create additional capacity for new connections and were used to determine the average scope of required upgrades. The scope of work on one of these feeders may include the following, depending on specific feeder needs:

- a three-phase voltage regulator on the main path of the feeder;
- one to three single-phase voltage regulators on lateral branches of the feeder;
- changing the phase of several single-phase laterals to balance voltages;
- voltage sensors to validate the voltage performance and monitor the feeder to potentially enable additional future capacity.

Hydro One expects this investment to increase micro-embedded generation hosting capacity by an average of approximately 220 kW per feeder, effectively doubling the available micro-embedded generation hosting capacity on the feeders addressed through this program.

Feeders will be prioritized based on demonstrated demand for additional hosting capacity, including feeders that have experienced prior customer micro-embedded generation application rejections due to capacity constraints, as well as cost considerations.

4.0 OUTCOMES

The investments will support the connection of additional micro-embedded generation to the system in the following ways:

- Remove existing barriers for customers to connect micro-embedded generation without causing service quality degradation.
- Prevent approximately 60 feeders from becoming constrained.
- Enable customer choice for customers who want to connect micro-embedded generation to contribute to the distribution system or participate in Ontario’s various programs, including potential future NWS programs offered by Hydro One.

- Create incremental capacity on the system to connect more micro-embedded generation.

4.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the investment in accordance with the Renewed Regulatory Framework (RRF):

Outcome Summary:

Customer Focus	• Maintain customer satisfaction by responding to customer requests to connect micro-embedded generation in areas with existing system constraints.
Operational Effectiveness	• Protect system safety and reliability outcomes while enabling the system to accommodate additional DER connections.
Public Policy Responsiveness	• Comply with the OEB's expectations as set out in the FEI. • Enable the connection of micro-embedded generation projects in the Province of Ontario under various programs. • Enable customer choice for customers who want to connect micro-embedded generation to contribute to the distribution system or participate in Ontario's various programs, including potential future NWS programs offered by Hydro One.

5.0 EXPENDITURE PLAN

Table 1 below summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 rate period and the forecast net capital expenditures for the 2028-2032 period. There are no forecast expenditures for Orillia RZ and Peterborough RZ.

Table 1 - Hydro One - Investment Expenditures

($M)	Plan[2] 23-27	Act/Fcst[3] 23-27	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	0.0	0.0	3.7	17.0	16.6	16.9	17.2	71.4
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**0.0**	**0.0**	**3.7**	**17.0**	**16.6**	**16.9**	**17.2**	**71.4**

2023-2027 EXPENDITURES

This is a new program and there were no expenditures during the 2023-2027 period.

2028-2032 EXPENDITURES

The proposed investments will increase micro-embedded generation hosting capacity on approximately 11 feeders in the first year of the rate period and approximately 45 feeders in each of the subsequent four years.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: MAINTAIN EXISTING MICRO-EMBEDDED GENERATION HOSTING CAPACITY

Under this alternative, Hydro One would not make investments to address micro-embedded generation hosting capacity constraints on the distribution system. Consequently, customers on constrained feeders would continue to have limited opportunities to connect micro-embedded generation and participate in provincial DER programs. The number of constrained feeders would also be expected to grow over time as micro-embedded generation adoption increases, resulting in fewer opportunities for customer participation and outcomes that are inconsistent with the objectives of the OEB's FEI.

[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[3] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

ALTERNATIVE 2: CAPACITY EXPANSION FOR FUTURE MICRO-EMBEDDED GENERATION GROWTH

This alternative involves a higher level of investment in system upgrades and mitigation measures to address an additional 440 feeders identified as having limited capacity to accommodate micro-embedded generation. While these feeders were not constrained as of December 31, 2025, increasing micro-embedded generation adoption over the planning period could result in future capacity constraints. Under this alternative, those constraints would be addressed proactively, with capacity upgrades implemented in advance of demonstrated customer demand. This would create approximately 141 MW of additional micro-embedded generation hosting capacity and enable up to 12,000 additional customer micro-embedded generation connections.

Although this alternative would support a greater level of micro-embedded generation adoption, it was not selected due to uncertainty regarding the timing and location of future demand on feeders that currently have available capacity. As a result, a significant portion of the investment could be deployed before the need for additional hosting capacity materializes. In addition, the increased scale of work would introduce execution risks, including the ability to complete a substantially larger volume of feeder upgrades within the planning period and the availability of key equipment, such as voltage regulators, required to undertake the work.

ALTERNATIVE 3: ADDRESS EXISTING AND NEAR-TERM MICRO-EMBEDDED GENERATION CONSTRAINED FEEDERS (RECOMMENDED)

This alternative would implement the investment at the recommended pace, addressing constraints on approximately 190 feeders that are currently constrained or forecast to become constrained over the planning period. On average, the investment is expected to increase micro-embedded generation hosting capacity by approximately 220kW per feeder. Collectively, this investment will create 43 MW of additional micro-embedded generation capacity and enable approximately 3,600 to 4,300 additional customer micro-embedded generation connections.

This alternative aligns with the expectations set out in the OEB’s FEI by meaningfully increasing opportunities for customers to connect micro-embedded generation and

participate in provincial DER programs. It also appropriately balances customer benefits, cost, and execution risk.

7.0 EXECUTION RISK AND MITIGATION

Hydro One connects a significant number of DERs to its distribution system every year on demand. The types of investments that Hydro One plans to make to alleviate capacity constraints on its distribution system feeders fall within the general scope of those typical DER demand connection upgrades that are commonly proposed and executed, so 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, material availability, and other such variables.

D-SS-08	SYSTEM MONITORING
Primary Trigger:	Asset Failure Risk
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	4.0	11.5	11.7	11.9	12.2	51.2
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

This investment involves the installation of online dissolved gas analysis monitoring and online thermovision monitoring devices to improve the condition monitoring of station transformers and reduce the frequency of failures. The primary trigger of the investment is asset failure risk. Station transformers identified as being at risk of imminent failure will be removed from service before failures occur. The investment is expected to improve system reliability by improving the identification of failing station transformers and reducing customer interruptions.

There are no planned capital expenditures for Orillia RZ or Peterborough RZ.

1.0 OVERVIEW

Transformer failures prior to planned intervention have a significant impact on reliability. This investment will improve Hydro One's ability to prevent transformer failures through the application of online monitoring technology. This investment Summary Document (ISD) includes two categories of investment:
(i) the installation of online dissolved gas analysis (DGA) monitoring equipment, and (ii) the installation of online thermovision monitoring equipment. Together, these technologies will provide continuous asset condition information, enabling earlier detection of emerging transformer issues and more timely corrective action. The primary benefits of the investment are improved reliability and safety through the increased prevention of transformer failures.

Distribution Station and Regulating Station transformers and regulators are currently monitored through annual oil sampling. Oil sample analysis is used to assess indicators of asset condition, including gases associated with electrical discharge and heating, moisture content, dielectric strength, and paper insulation degradation within the transformer. Through oil sampling, transformer and regulator corrective repair candidates are selected annually.

While the current monitoring approach has contributed to the avoidance of equipment failures, annual testing provides only periodic condition assessments and may not identify rapidly developing issues between sampling intervals. Consequently, transformer failures continue to occur, creating reliability risks and operational impacts. The proposed online monitoring technologies will complement the existing inspection and testing program by providing continuous condition information, improving Hydro One's ability to detect deterioration and intervene before failures occur.

This investment includes the installation of online dissolved gas analysis ("DGA") data monitors to complement ongoing assessments via oil sampling. Online DGA monitoring can supply data that traditional oil sampling cannot and therefore is expected to reduce the transformer and regulator failure rate. Online transformer DGA monitors provide the following benefits:

- Give early warning of rapidly deteriorating condition, such as internal electrical and thermal faults prior to failure through remote alarms. This allows for just-in-time corrective maintenance to prevent a failure or an opportunity to proactively manage the failure in a controlled manner.
- Correlate gas increases with peak transformer loading periods. Elevated gases may not be identified by oil sampling if the sampling is not taken during peak loading periods.
- Identify brief periods of overheating or partial discharge that “leveled off” over time, which periodic oil sampling cannot catch.

Distribution Stations and Regulating Stations currently undergo thermovision inspections by camera once every two years to identify abnormal temperature conditions, or "hot spots," on electrical equipment. These inspections support asset condition assessment and help identify equipment requiring maintenance or corrective action. However, because inspections are performed periodically, thermal issues that emerge between inspection intervals may not be detected until the next scheduled inspection.

This investment includes the installation of online thermovision monitoring to complement ongoing manual monitoring. Online thermovision provides data that manual inspections cannot and therefore is expected to reduce hot spot related failures.

Online thermovision monitoring provides the following benefits:

- Real-time temperature readings, temperature trending and alarm capabilities.
- Alarm communication capabilities where data can be sent to a centralized location, and Hydro One maintenance staff can be deployed to investigate faulty equipment prior to equipment failure.

1.1 INVESTMENT NEED

The station transformer fleet is aging, with 46% beyond ESL and 20% in poor condition; due to their current state, the fleet will benefit from a more robust monitoring program. As discussed in Section 1.2.1.1 below, a large percentage of station transformers have exceeded their expected service life (ESL). Internal transformer components degrade over

time, and asset condition is one of the leading predictive indicators of transformer failure. This investment will improve Hydro One's ability to identify and monitor the status of station transformers to better mitigate the likelihood of failure and the resultant customer outages and demand replacement work.

STATION TRANSFORMER DEMOGRAPHICS

Station transformers convert a high-level voltage (typically 115, 44 or 27.6kV) to a lower distribution voltage (typically 27.6, 25, 13.8, 12.47, 8.32 or 4.16kV). This asset class also includes regulating transformers, which provide voltage control on the distribution system. Hydro One owns and operates 1,228 distribution station transformers (including transformers in Orillia RZ and Peterborough RZ) as categorized below in Table 1 by primary voltage level.

Table 1 - Transformer Count by Voltage Level

Primary Voltage Level	Hydro One	Orillia RZ	Peterborough RZ
230kV	1	-	-
115kV	140	-	-
44kV	776	11	31
27.6kV	224	-	-
< 27.6kV	45	-	-

Generally, station transformers are aging assets that will benefit from a more robust monitoring program. As shown below in Tables 2 and 3, approximately 46% of Hydro One's station transformers are at or have exceeded their ESL of 50 years, and approximately 20% are in poor condition.

Table 2 - Transformer Age and ESL in 2025 and in 2032 Without Transformer Replacement

	Average Age	At or Exceed ESL in 2025	At or Exceed ESL in 2032 without transformer replacement
Hydro One	43 years	45%	55%
Orillia RZ	32 years	36%	45%
Peterborough RZ	58 years	87%	94%

Table 3 - Station Transformer Condition

	Poor	Fair	Good
Hydro One	231 (19%)	244 (21%)	711 (60%)
Orillia RZ	-	2 (18%)	9 (82%)
Peterborough RZ	11 (36%)	1 (3%)	19 (61%)

Transformers that are at or have exceeded their ESL, or transformers in poor condition have a higher risk of failure compared to the overall transformer population. Transformer components deteriorate as they age due to transformer loading, switching, lightning surges, moisture contamination, and paper insulation degradation. Transformer monitoring is one of the leading predictive indicators of failure. The average age of transformers which failed between 2021-2025 was 47 years. In addition, degradation of transformer health is not always a gradual process. In some cases, the degradation can be rapid, and thus transformers which have been evaluated through monitoring to be in "good" or "fair" condition have also failed.

Considering the aging population of the transformer fleet and the current limitations of the monitoring program, improved monitoring through this investment is expected to result in the identification of a greater volume of transformers with significant deterioration or deficiencies and consequently afford Hydro One the opportunity to prevent failure through replacement or corrective repair.

STATION TRANSFORMER PERFORMANCE

When a transformer fails before intervention, it can have a significant impact on reliability. This is because 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 because load cannot typically be transferred among rural stations, which are primarily fed from a radial system.

In these instances, service restoration requires that a Mobile Unit Substation (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 on average seven hours to install before power can be temporarily restored to customers. In severe cases, these outages can take over 20 hours depending on the distance of the nearest available MUS to the station, and the availability and condition of the MUS structures that are required to connect 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 approximately seven hours.
- *Class 2 Failures* – Station transformer failures avoided through timely corrective or capital intervention. Such intervention is currently triggered by oil sampling indicating that failure is imminent. 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.

Figure 1 shows the number of transformer failures resulting in customer interruptions (Class 1) and the number of imminent failures avoided by the removing transformers from service (Class 2) in the Hydro One RZ. In the Orillia RZ, no transformer failures have occurred since the acquisition in 2021. In the Peterborough RZ, one Class 2 transformer failure occurred in 2022, and one Class 1 transformer failure occurred in 2023.



Figure 1: Hydro One Station Transformers Failures[1]

From 2016 to 2025, there was an average of six "Class 1 failures" annually, and nine "Class 2 failures" annually across all rate zones. Although annual oil sampling and manual thermovision decrease the rate of major failures, the data provided has gaps, and further decreases are expected through this investment.

STATION TRANSFORMER TESTING & INSPECTION

Hydro One's current transformer monitoring approach helps to identify the population of station transformers in poor condition. 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:

[1] For more information on station transformer performance, refer to DSP Section 3.2, subsection 3.2.2.1.3

- 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.

This investment is focused on strengthening Hydro One's capabilities with respect to oil sampling and thermographic inspections, each of which are discussed in more detail below.

Current Station Transformer Oil Sampling Strategy

Hydro One's historical approach for monitoring the internal condition of transformers has solely relied upon oil sampling. Every Spring, an oil sample is taken from the transformer main tank and under-load tap-changer (ULTC) compartment (if equipped). The sample is then sent to a third-party lab for industry standard diagnostic testing, including DGA, standard oil tests (SOT), and furan analysis.[2]

If an oil sample result is unsatisfactory, further diagnostic testing and internal inspection may be undertaken.

Through annual oil sampling, Hydro One has been able to avoid an average of nine Class 1 failures per year which would have otherwise resulted in lengthy customer interruptions (seven hours per failure on average). The failures avoided are related to internal faults within the main tank (including electrical / thermal faults identified through the DGA test, or high moisture/low dielectric identified through the SOT).

[2] DGA testing enables electrical and thermal faults to be detected by monitoring levels and combinations of various gases including hydrogen (H2), methane (CH4), ethane (C2H6), ethylene (C2H4), acetylene (C2H2), carbon monoxide (CO) and carbon dioxide (CO2). SOT is a test for oil quality and includes moisture content, dielectric strength and acidity. A high moisture content or humidity level in the oil reduces the dielectric strength and increases insulation aging. Furan testing is a measure related to overall insulation degradation and end of life of a transformer. It measures degradation of paper insulation associated with transformer windings.

Despite annual oil sampling, there is still an average of six Class 1 failures per year. From 2016 to 2025, there were 58 Class 1 failures which were associated with the following:

- Internal faults within the main tank – 50% (29)
- Bushing failures – 31% (18)
- Under-load tap-changer failures – 10% (6)
- Failures initiated by system faults external to the station – 9% (5)

For the reasons described in more detail in Section 1.3, installing online DGA monitoring devices can help to reduce transformer failures associated with internal faults within the main tank, which are not effectively detected through current testing methods. Transformer failures associated with bushing failures are addressed separately through the proposed online thermovision monitor installations, discussed below.

Current Manual Thermovision Strategy

Currently, Hydro One uses handheld cameras to perform manual thermovision inspections of station power equipment to identify hot spots and other signs of abnormal heating in electrical equipment or components. The primary objective of this program is to detect and identify overheated components and monitor equipment exhibiting signs of deterioration, thereby enabling corrective action before overheating leads to equipment failure.

Thermovision scans are currently performed on a two-year cycle, with about 50% of stations scanned each year. Despite this inspection interval, equipment failures related to component overheating continue to occur. From 2016 to 2025, there were 18 Class 1 transformer failures associated with transformer bushings, representing 31% of all Class 1 failures in the period.

The condition of transformer bushings cannot be effectively monitored through routine oil sampling because obtaining bushing oil samples requires the transformer to be removed from service. Manual thermovision inspections only provide periodic snapshots of equipment temperature; as a result, they may not capture developing thermal anomalies or changes in operating conditions that occur between inspections and can ultimately lead to equipment failure.

For the reasons explained in more detail in Section 1.3, the installation of online thermovision monitoring devices can help to reduce transformer bushing failures, which manual thermovision scans are unable to identify.

2.0 INVESTMENT DESCRIPTION

This investment involves the installation of online DGA and online thermovision monitoring devices on station transformers to enhance condition monitoring and reduce the frequency of transformer failures. Online DGA monitoring helps identify internal faults within the transformer main tank, while online thermovision monitoring helps detect abnormal temperature conditions associated with transformer bushings, which are among the leading causes of transformer failures. By providing continuous monitoring of these critical components, the investment will improve Hydro One's ability to identify deteriorating transformer conditions, enabling timely corrective action and planned equipment replacement or removal from service before failures occur.

STATION TRANSFORMER ONLINE DGA MONITORING STRATEGY

Online DGA monitors offer several benefits which complement Hydro One’s existing oil sampling program. Unlike annual oil sampling, online DGA monitors continuously assess transformer condition by measuring dissolved gas levels at frequent intervals, such as every 30 minutes. This enables the early detection of rapidly developing internal faults and deterioration that may occur between scheduled oil sampling events and therefore may not be identified through periodic testing alone.

Online DGA monitoring is achieved through the installation of electronic monitoring devices on transformers that automatically measure and record dissolved gas concentrations. The data is transmitted through a cellular network to a centralized monitoring platform, where it is stored, analyzed, and used to generate alarms when abnormal gas trends or indications of rapid deterioration are detected. This continuous monitoring capability enables Hydro One personnel to respond proactively to emerging transformer condition issues before they result in failure.

Online transformer DGA monitors provide the following benefits:

- Provide early warning of rapidly deteriorating condition, such as internal electrical faults prior to failure through remote alarms. This allows for just-in-time corrective maintenance to prevent a failure or an opportunity to proactively manage the failure in a controlled manner.
- Correlate gas increases with peak transformer loading periods. Elevated gases may not be identified by oil sampling if not taken during peak loading periods.
- Identify brief periods of overheating or partial discharge that have “leveled off” over time, which periodic oil sampling cannot catch.

From 2016 to 2025, 29 Class 1 failures were related to internal faults within the main tank, averaging three failures per year. As there were an average of six Class 1 failures annually during the same period, approximately half were attributable to internal faults within the main tank. These faults were not identified early enough through traditional oil sampling to prevent failure. Of the 29 failures, 14 occurred in transformers that had previously been assessed as being in “good” condition, seven in “fair” condition and eight in “poor” condition. If Hydro One Distribution station transformers are retrofitted with online DGA monitoring, it is estimated that approximately half of Class 1 failures could be avoided annually for the useful life of the online DGA monitors.

Table 4 below shows the proposed number of transformer online DGA monitor installations from 2028 to 2032. There are no planned installations in the Orillia RZ and Peterborough RZ from 2028 to 2030.

Table 4 - Transformer Online DGA Monitor Annual Installations

Zone	Component	Plan 23-27	Forecast 23-27	Total 28-32
Hydro One	# of transformers to be Monitored	-	-	956
	# of Associated DGA Devices	-	-	1090

Candidates for online DGA monitor installations will be prioritized based on the following criteria with the following approximate quantities:

1. Transformers which require frequent oil sampling to monitor condition trends (quantities determined annually based on oil sample results).
2. Transformers with poor condition DGA or moisture test results (102).
3. Transformers with fair condition DGA or moisture test results (176).
4. More critical transformers with higher downstream customer counts (76).
5. Economic value of transformers, more costly to replace (ex. 115kV, higher MVA, etc.) (142).
6. Transformers beyond age 30; which is the age when failures begin to occur (460 of 537).

The cost effective online DGA monitors proposed under this investment will measure three or four key gases, as well as moisture content. In comparison, traditional oil sampling captures nine dissolved gases, moisture content, oil quality parameters, and indicators of paper/cellulose degradation known as furans. Consequently, online DGA monitors are not intended to replace traditional oil sampling, rather supplement it. However, online DGA monitors provide a significant advantage through their continuous monitoring capability. By collecting data at frequent intervals, they can rapidly detect developing electrical and thermal faults that may emerge between scheduled oil sampling events. This enhances Hydro One's ability to identify deteriorating transformer conditions at an earlier stage and supports more timely, condition-based maintenance decisions.

Degradation due to dielectric strength, and paper insulation in general is a more gradual process and typically not as rapid as electrical and thermal faults. Therefore, traditional oil sampling continues to be a cost effective method for monitoring transformer condition, in conjunction with online DGA monitoring.

STATION TRANSFORMER ONLINE THERMOVISION MONITORING STRATEGY

This investment includes the installation of online thermovision sensors for real-time monitoring of DS transformer bushings. Although Hydro One operates a manual thermovision program to scan stations on a two-year annual cycle, there have still been 18 Class 1 transformer failures associated with bushing components from 2016 to 2025. The current two-year manual thermovision inspection cycle cannot detect all overheating equipment.

Online thermovision monitoring solutions can provide real-time temperature readings, temperature trending and alarm capabilities. Alarms can be sent to a centralized location, and Hydro One maintenance staff can be deployed to investigate faulty equipment prior to equipment failure. Table 5 below illustrates the planned number of monitoring devices and the number of transformer they will be deployed to monitor.

Online thermovision monitors provide the following benefits:

- Real-time temperature readings, temperature trending and alarm capabilities.
- Optimal alarm communications sending data to a centralized location allowing Hydro One maintenance staff to be deployed to investigate faulty equipment prior to equipment failure.

Table 5 - Transformer Online Thermovision Monitor Annual Installations

Zone	Component	Plan 23-27	Forecast 23-27	Total 28-32
Hydro One	# of transformers to be monitored	-	-	82
	# of associated thermovision devices	-	-	270

There are no planned installations in the Orillia RZ and Peterborough RZ between years 2028 to 2030.

Prioritization of transformer candidates for online thermovision monitor installations during the 2028-2032 planning period will focus on more critical transformers with higher downstream customer counts.

3.0 OUTCOMES

Customers will benefit from this investment through improved reliability. Enhanced transformer condition monitoring will enable earlier identification of deteriorating equipment and support timely repair, replacement, or other corrective actions. Improved monitoring of internal transformer faults and bushing conditions will increase Hydro One's

ability to identify transformers exhibiting signs of potential failure and, where appropriate, remove them from service in a planned manner before customer interruptions occur. By preventing transformer failures and associated outages, the investment will also reduce safety risks to customers.

3.1 OEB RRF OUTCOMES

Table 6 below presents the anticipated benefits of the investment in accordance with the Ontario Energy Board's Renewed Regulatory Framework:

Table 6 - Outcome Summary

Customer Focus	• Improved reliability by identifying failing transformers and removing them from service before they fail thereby maintaining supply to customers
Operational Effectiveness	• Maintain distribution system reliability, operation and safety by identifying failing transformers and removing them from service • Reduce safety risks associated with failed equipment by proactive identification of failing assets
Public Policy Responsiveness	• Supports compliance 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

4.0 EXPENDITURE PLAN

Table 7 below summarizes Hydro One's aggregate planned and forecast net capital expenditures for the 2023-2027 rate period and the forecast net capital expenditures for the 2028-2032 planning period. There are no planned, annual or forecasted net capital expenditures for Orillia RZ or Peterborough RZ. These expenditures are based on the unit prices to install the online DGA and thermovision monitoring devices, as well as the proposed number of units in Tables 4 and 5.

Table 7 - Hydro One - Investment Expenditures[3]

($M)	Plan[4] 23-27	Act/Fcst [5] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Investment Expenditures	0.0	0.0	4.0	11.5	11.7	11.9	12.2	51.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**0.0**	**0.0**	**4.0**	**11.5**	**11.7**	**11.9**	**12.2**	**51.2**

2023-2027 EXPENDITURES

This is a new program and there were no expenditures during the 2023-2027 period.

2028-2032 EXPENDITURES

Over the 2028-2032 planning period, forecast expenditures are $51.2M. These expenditures reflect the planned deployment of the online DGA and thermovision monitoring devices identified in Tables 4 and 5.

The factors influencing the cost of the investment include:

- The cost of the online DGA and online thermovision monitoring devices from selected manufacturers;
- The cost of cellular communication devices to transmit the data and store it in monitoring software; and
- The cost to install these devices on each transformer.

Controllable costs have been minimized through the evaluation of vendor products and selecting equipment that are cost effective and easy to install with minimal labour.

[3] Figures presented in the tables may not sum to the totals shown due to rounding
[4] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[5] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred investment.

ALTERNATIVE 1: STATUS QUO

In this alternative, Hydro One would continue to take oil samples from transformers on an annual basis to monitor their condition and continue to perform manual thermovision scans at stations every two years to locate hot equipment. As noted above, from 2016 to 2025 there was an average of six Class 1 failures annually, and nine Class 2 failures annually. The status quo is expected to result in the continued avoidance of approximately 60% (9 of 15) of major failures per year.

The status quo would maintain a monitoring approach that does not identify certain known leading issues causing failure. Based on historical performance, approximately six major failures would be expected to continue occurring annually, including failures that enhanced monitoring may provide an opportunity to avoid through earlier detection and intervention.

For the reasons identified above, this alternative is rejected.

ALTERNATIVE 2: INCREASE OIL SAMPLE & THERMOVISION FREQUENCY

In this alternative, Hydro One would increase the oil sample frequency from once per-year to twice per-year. Hydro One would also increase the manual thermovision inspection frequency from once every two years to once annually.

Increasing the oil sample frequency is not expected to reduce the annual number of “Class 1 failures” because “Class 1 failures” are associated with internal faults within the main tank, bushing failures, under-load tap-changer failures and failures initiated by system faults which annual DGA testing cannot catch. In some cases, the internal degradation of a station transformer can occur far more rapidly than a six-month oil sample time interval could detect. Also, shortening the oil sample frequency is unlikely to capture the annual peak loading period for which dissolved gases may be at their peak.

Increasing the manual thermovision inspection frequency may identify some additional bushings that are heating prior to failure, but the alternative is inferior to online thermovision monitoring for the reasons described below in the selected alternative.
For the reasons identified above, this alternative is rejected.

ALTERNATIVE 3: ONLINE GAS & THERMOVISION MONITORING (RECOMMENDED)

Online DGA Monitors

In this recommended alternative, online DGA monitors will be installed on station transformers to monitor their internal condition with frequent monitoring, trending and communication of gases and moisture content that can identify rapid degradation of station transformer condition. The online gas monitors will be utilized in conjunction with annual oil sampling to monitor condition. It is expected that the annual average number of Class 1 failures can be reduced by approximately 50% once online DGA monitors are deployed during the planning period. This is because 51% of historical Class 1 failures have been associated with internal faults within the main tank of the transformer, which DGA monitors are designed to detect.

Online Thermovision Monitors

In this recommended alternative, online thermovision monitors will be installed on station transformers to monitor for hot spots on bushings which can lead to failure. There has been an average of two transformer bushing related failures annually from 2016 to 2025. In more recent years, the average number of bushing related failures annually is three. Not all overheating equipment can be detected and associated failures avoided with a manual thermovision inspection cycle. The deployment of these online thermovision sensors will be prioritized based on criticality with priority given to transformers with higher quantities of downstream customers. It is expected that annual bushing related failures will be reduced with the deployment of these sensors.

ALTERNATIVE 4: ONLINE GAS & THERMOVISION MONITORING - REDUCED RATE

This alternative considers the installation of online DGA monitors and online thermovision monitors at a reduced rate compared to the planned rates shown in Tables 4 and 5 which align with the recommended Alternative 3.

Online DGA Monitors

The reduced online DGA monitor installation rate would exclude the installation of DGA monitors for Priority 6 – “Transformers beyond age 30; which is the age when failures begin to occur”. Of the 29 transformers which experienced Class 1 failures from 2016 to 2025 associated with internal faults within the main tank, 14 were evaluated to be in “good” condition and seven were evaluated to be in “fair” condition based on oil sampling prior to the failure. Therefore, for the deployment of online DGA monitors to be most effective in reducing Class 1 failures, their deployment cannot be limited to transformers in “poor” condition; rather installations must also include those transformers that were in “good” and “fair” condition. Hydro One rejected the reduced accomplishment rate for this reason.

Online Thermovision Monitors

The proposed online thermovision monitor installation rate is already reduced. It will allow for the completion of most candidates that are critical transformers with higher downstream customer counts. However, additional candidates such as those with higher economic values that are more costly to replace (ex. 115kV, higher MVA, etc.) are not included at this accomplishment rate and will be considered in future planning periods. For this reason, Hydro One did not consider a further reduction to the proposed accomplishment rate.

6.0 EXECUTION RISK AND MITIGATION

The primary execution risk associated with this program is the ability of the selected vendors for online DGA monitors, online thermovision monitors, and cellular communication devices to manufacture and deliver the required number of units within the project schedule. This risk is mitigated through ongoing engagement with vendors to monitor manufacturing capacity, production schedules, and delivery timelines, enabling Hydro One to identify and address potential supply constraints early in the implementation process.

D-SS-09	INTELLIGENT GRID PLATFORM
Primary Trigger:	Public Policy Responsiveness
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	6.3	2.7	0.5	11.1	11.1	**31.7**

Prepaid Expenditures Related to Cloud:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	2.5	13.5	3.6	5.1	3.5	**28.2**

Summary:

The Intelligent Grid Platform is a portfolio of investments centered on an advanced distribution management system (ADMS). The ADMS is a software platform that unifies the capabilities of several standalone systems allowing for improved reliability and efficiency, strengthened system resilience, and supports the cost-effective integration and management of distributed energy resources (DERs)

The standalone systems within the scope of this investment include the distribution management system (DMS), Outage Management System (OMS, previously known as the Outage Response Management System or ORMS), supervisory control and data acquisition (SCADA), and Grid Distributed Energy Resource Management System (Grid DERMS) to monitor, control, and optimize distribution grid operations in real time. The Intelligent Grid Platform will also integrate complementary capabilities, including Edge Distributed Energy Resource Management (Edge DERMS), Climate Risk Intelligence System (CRIS), Intelligent Vegetation Management System (IVMS), market management, dynamic hosting and capacity maps, customer experience management and asset performance.

The investment will collectively increase system visibility, enhance operational control, and enable advanced analytics and automation.

The Intelligent Grid Platform will be implemented in two stages. Stage 1 (2025-2028), is already underway and focuses on the design, development, testing, and implementation of the ADMS. The ADMS is expected to enter service in 2028 as the foundational platform of the intelligent grid. During this stage, Grid DERMS, Edge DERMS, and CRIS are being implemented as standalone solutions to address near-term operational and business requirements. Following ADMS in-service, these capabilities will be integrated to establish a fully integrated intelligent grid platform.

Stage 2 (2029-2032) builds on this foundation through the phased implementation of additional capabilities, including vegetation management, asset performance, market management, dynamic hosting and capacity maps, and customer experience management. These investments will progressively expand the functionality, customer benefits, and business value of the Intelligent Grid Platform throughout the planning period.

There are no planned capital expenditures for Orillia RZ or Peterborough RZ.

1.0 OVERVIEW

This Investment Summary Document supports Hydro One's request for capital and prepaid cloud expenditures over the 2028-2032 period to complete the implementation of the Intelligent Grid Platform and expand its capabilities. This investment builds on foundational work underway during the 2023-2027 period.

Hydro One's distribution system is undergoing a fundamental transformation as it evolves from a historically one-directional network to a more dynamic and decentralized grid. Increasing adoption of DERs—including distributed generation, battery storage, electric vehicles, and demand-side technologies—is altering load profiles and introducing bi-directional power flows. These changes are amplified by the unique characteristics of Hydro One's system, long rural radial feeders with limited operational visibility and control, low customer density in rural and heavily forested areas, which serve to increase both operational complexity and vulnerability to extreme climate related events. This transformation is driven by evolving customer expectations, electrification trends, provincial policy direction, and an evolving regulatory landscape with a growing focus on enabling DER integration and non-wires solutions (NWS).

The 2023-2027 OEB-approved settlement included investments to upgrade its Outage Response Management System (ORMS, now known as the OMS) and DMS under projects in GSP Section 4.11 G-GP-17 and GSP Section 4.11 G-GP-18 as these systems were aging with increasing maintenance costs and risk of failure. As these investments advanced from the planning stage to detailed design and cost estimation, Hydro One determined that proceeding with discrete ORMS (now OMS) and DMS upgrades would not best meet system needs. Accordingly, Hydro One elected to discontinue the standalone upgrade initiatives, resulting in a work scope variance, and instead pursue an integrated portfolio of investments in an Intelligent Grid Platform.

The Intelligent Grid Platform is centered on an ADMS that brings together core operational systems—the Distribution Management System (DMS), Outage Management System (previously known as the Outage Response Management System or ORMS), and Grid Distributed Energy Resource Management System (Grid DERMS)—along with supporting

capabilities (e.g., Edge DERMS and Climate Risk Intelligence System) and enabling applications.

Unlike today's multiple standalone systems, the ADMS provides an integrated operational layer enabling Hydro One to fully integrate and leverage complementary grid modernization investments, such as AMI 2.0 and Distributed Intelligence, in real-time operations. Collectively, the Intelligent Grid Platform establishes a cohesive and scalable foundation to improve data consistency, enhance grid visibility to operators, enable advanced analytics and automation, and improve operational control across the distribution system. This integrated approach improves reliability and efficiency, strengthens system resilience, and supports the cost-effective integration and management of DERs.

For example, today, when a fault occurs on a rural feeder, distribution operators must rely on customer calls to the Control Room reporting an outage, then gather information from multiple standalone systems to assess the event (i.e., D-SCADA alarms to identify the affected equipment, OMS to determine impacted customers, and the DMS to define switching plans and restoration options). This process requires operators to manually correlate information across systems before dispatching crews and directing field activities. With the ADMS, these capabilities will be integrated within a single operational platform leveraging a single distribution network model, providing a real-time view of the as-built and as-operated distribution network. Operators can immediately identify the fault location, identify affected customers, determine switching plans as required, and implement restoration activities using one system. This integrated operating environment supports faster fault location, isolation, more coordinated switching plans, improved situational awareness, and more efficient crew dispatch.

The ADMS also integrates data and capabilities delivered through the AMI 2.0 and Distributed Intelligence (DI) investments described in D-SR-12. For example, meter and location data sourced from AMI 2.0 and DI applications will be incorporated into real-time operations, enhancing outage detection, improving visibility across the lower-voltage F-Class distribution system, and supporting more informed operational decision-making.

The investment aligns with the lifecycle of the organization's core operational systems. The current ORMS has been functionally obsolete for several years and requires extended support, and the existing DMS will exit mainstream support by the end of 2026. Ongoing reliance on these systems would result in increasing operational risk and would constrain the organization's ability to meet emerging customer and operational needs.

Hydro One's Intelligent Grid Platform investment adopts an approach aligned with leading North American utilities, including Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and Tampa Electric Company (TECO), which have implemented an ADMS as the cornerstone of their distribution grid modernization programs.[1] These utilities have invested in an ADMS to improve reliability, strengthen operational visibility and control, enhance outage response and restoration, support DER integration, and increase resilience to evolving grid and climate-related challenges. Hydro One's approach similarly positions ADMS as the foundational platform enabling a more intelligent, flexible, and resilient distribution system.

The Intelligent Grid Platform, described in detail in section 3, is planned to be implemented in two stages.

Stage 1 (2025-2028) is centered on the design, development, and testing of the ADMS, which is expected to enter service in 2028 as the core platform of the intelligent grid. The ADMS incorporates both DMS functionality and OMS functionality, with the OMS component replacing and expanding upon the capabilities previously provided by the legacy Outage Response Management System (ORMS). In parallel, Grid DERMS, Edge DERMS, and the Climate Risk Intelligence System (CRIS) will be placed into service as stand-alone operational systems to support near-term operational requirements.

[1] PG&E, PG&E Grid Modernization Report, (April 2024), (https://gridworks.org/wp-content/uploads/2024/04/PGE-Grid-Modernization-Report_April-2024.pdf). Southern California Edison Grid Modernization Report, (March 15, 2024), (https://gridworks.org/wp-content/uploads/2024/04/SCE-2024-Grid-Modernization-Progress-Report.pdf). Tampa Bay Electric (TECO), Docket 20240026-E1, Direct Testimony of David Lukcic. p. 21 (https://www.tampaelectric.com/495939/siteassets/files/rates/2024/02_testimony-and-exhibits/08_final_direct-testimony-and-exhibit-of-david-lukcic_bates.pdf)

Following ADMS implementation in 2028, these systems are planned to be integrated with the ADMS to establish a fully integrated intelligent grid platform.

Stage 2 will be delivered incrementally over 2029-2032, building on the foundation established in Stage 1 and expanding the capabilities of the Intelligent Grid Platform. This stage includes the implementation of vegetation management, asset performance, market management, and enablement applications, including dynamic hosting and capacity maps and customer experience management. These capabilities will be deployed in phases, providing progressively enhanced functionality and value throughout the investment period.

2.0 INVESTMENT NEED

2.1 HYDRO ONE DISTRIBUTION SYSTEM CONTEXT

Hydro One operates one of the largest and most geographically dispersed distribution systems in North America, serving a predominantly rural and remote customer base across Ontario. The network is characterized by long radial feeders, limited redundancy, and significant exposure to extreme weather events, which create operational challenges distinct from more urban utilities. These characteristics drive increased complexity in maintaining reliable service, particularly during large-scale weather-related outage events.

Hydro One's journey toward a more modern distribution grid has unfolded over decades, evolving from early mechanical and paper-based operations to an increasingly automated digital grid featuring sensors, cellular communications, and control systems. From an operational perspective, Hydro One's distribution system provides strong visibility and control at distribution stations, where SCADA provides real-time monitoring of breaker status, feeder loading, and voltage conditions, along with the ability to remotely operate key devices.

However, this level of visibility and control diminishes significantly beyond the distribution station, across the long rural F-class feeders that make up much of the service territory. Along these feeders, visibility is limited, with minimal real-time system data, and

operations remain largely dependent on manual processes, requiring field crews to locate faults and perform switching activities in person.

These limitations have direct customer, operational, and system-planning implications. From a customer perspective, it contributes to longer outage durations, delayed fault location, and less predictable restoration times, particularly in rural and more remote areas where travel distances are significant. From an operational efficiency perspective, reliance on manual processes results in increased crew time, travel requirements, and reactive decision-making, reducing overall productivity and increasing costs. From a grid evolution perspective, limited insight into real-time feeder conditions constrains Hydro One's ability to accommodate DERs, manage electrification-driven load growth, and implement NWS in line with regulatory and customer expectations.

To address these challenges, Hydro One is progressively evolving from a system that is primarily station-visible and manually operated to one that is more fully observable, increasingly controllable, and capable of coordinated, real-time operation across the sub-transmission and distribution network.

2.2 NEEDS

Within the above context, Hydro One faces a set of interconnected needs that can be grouped into five primary areas: 1) Reliability; 2) Efficiency; 3) Public Policy/Regulatory Direction; 4) Responding to Climate Risk; and 5) Responding to Obsolescence.

2.2.1 RELIABILITY NEEDS

Hydro One operates across a large and predominantly rural service territory, where long feeder lengths, limited redundancy, and exposure to severe weather events contribute to higher outage frequency and extended restoration times. As presented in DSP Section 3.1.2 Distribution System and Service Area, several specific characteristics unique to Hydro One contribute to reliability challenges:

- Hydro One's distribution system is predominantly radial and has limited alternate-supply capability in many areas. Where no feeder tie or transfer path is available, an upstream fault can interrupt all customers downstream and service cannot be restored until the fault is located, isolated, and repaired. Many rural and northern feeders extend

for more than 100 kilometers and include numerous branches and vegetation interfaces.

- Approximately 91% of Hydro One's distribution line is overhead. This configuration is directly exposed to wind, ice accretion, lightning, tree contact, falling branches, vehicle contact, and other external hazards. Hydro One's proportion of overhead lines is materially higher than that of the other large Ontario distributors, all of which are below 60%.
- Hydro One's system also contains a material population of off-road lines. Approximately 400 feeders, or about 15% of all feeders, have a significant proportion of off-road plant. When an off-road asset fails, patrol and repair may require property access, travel on foot, tracked vehicles, remote-boom derricks, helicopters, or other specialized equipment. These access requirements generally increase outage duration, repair complexity and execution cost relative to comparable on-road assets. As a result, off-road feeders can experience approximately 2.3 times the average outage duration of roadside feeders.

Current operations are constrained by limited real-time visibility of the distribution system beyond distribution stations, and reliance on time-consuming manual line patrols to precisely locate equipment damage and faults. Investments to enhance real-time or near real-time situational awareness on feeders and operational automation will improve the speed and accuracy of fault location and restoration, support more efficient system operations, and contribute to improved reliability performance, reduced outage duration, and enhanced customer service.

2.2.2 EFFICIENCY NEEDS

There is a need to improve operational efficiency as the distribution system continues to increase in complexity. Characteristics such as long feeder circuits, diverse feeder configurations, growing penetration of DERs, and evolving load profiles place greater demands on system monitoring, control, and decision-making. Current operations are constrained by limited voltage optimization capabilities, incomplete visibility into feeder conditions, and fragmented tools for managing system data and events. These challenges are further compounded by limited visibility of DERs connected to F-Class feeders,

inadequate location awareness, and the inability of the DMS to directly poll meter voltage data. Collectively, these constraints reduce situational awareness, limit operational effectiveness, and hinder efforts to optimize system performance, reliability, and customer service.

Control room operators are required to manage growing volumes of information without fully integrated systems to support real-time prioritization and decision-making. This creates inefficiencies in system operations and limits the ability to optimize performance. Accordingly, there is a need for enhanced, integrated capabilities, including improved voltage management, better visibility into feeder conditions, and more effective tools for operator decision support. Addressing these needs will enable more efficient system operations, reduce losses and operating costs, and improve the effectiveness of resource deployment during both normal operations and outage events.

2.2.3 RESPONDING TO PUBLIC POLICY/REGULATORY DIRECTION

Hydro One must respond to public policy and regulatory direction, encouraging electrification and consideration of cost-effective integration of NWS and DERs as alternatives to traditional infrastructure investments.[2] These changes introduce bi-directional power flows, greater load variability, and increased system complexity across a network not originally designed for such conditions. Existing systems do not fully provide the visibility, coordination, and control required to support these needs.

2.2.4 RESPONDING TO CLIMATE RISK

At the same time, there is a growing need to enhance system resilience in response to escalating climate risks, particularly given Hydro One's extensive and heavily forested service territory, which is inherently more vulnerable to extreme weather events. Strengthening the organization's ability to anticipate, prepare for, and respond to climate-

[2] OEB, *OEB Framework for Energy Innovation: Setting a Path Forward for DER Integration*, (January 2023), (https://www.oeb.ca/sites/default/files/FEI-Report-20230130.pdf). OEB, *OEB Non-Wires Solutions Guidelines for Electricity Distributors,* (March 28, 2024), (https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-04/OEB_2024%20NWS%20Guidelines_20240328.pdf). Government of Ontario, *Energy For Generations: Ontario's Integrated Energy Plan to Power the Strongest Economy in the G7*, (June 2025), Chapter 4 Ontario's Future Electricity Grid (https://www.ontario.ca/files/2025-07/mem-energy-for-generations-en-2025-07-18.pdf).

driven impacts is increasingly important. This includes leveraging predictive analytics and forecasting capabilities to identify potential system impacts in advance, enabling more effective pre-positioning and deployment of crews, materials, and other critical resources to support restoration efforts and minimize outage duration.

2.2.5 RESPONDING TO TECHNOLOGICAL OBSOLESCENCE

In parallel, Hydro One's existing distribution operating systems are aging, creating increasing supportability and performance risks and necessitating replacement or significant upgrade. The current ORMS has been functionally obsolete for several years and requires extended support, and the existing DMS will exit mainstream support by the end of 2026. A like-for-like replacement would not be prudent given advancements in grid technologies and evolving system requirements. It would also fail to leverage complementary investments, such as AMI 2.0, which can significantly enhance visibility at the grid edge through location awareness and voltage monitoring DI applications. Leveraging these capabilities across both operations and planning is critical to enabling significantly greater visibility at the grid edge.

3.0 INVESTMENT DESCRIPTION

Meeting the needs discussed above requires a strategically integrated portfolio of investments that collectively enables a more intelligent distribution system (see Figure 1). At the core of this portfolio is the ADMS, an integrated software platform that unifies distribution management, outage management, SCADA, and Grid DERMS capabilities to monitor, control, and optimize distribution grid operations in real time. Reinforcing this foundation are key supporting capabilities—including Edge DERMS, climate risk intelligence, vegetation management, asset performance, and market management systems—that together form a cohesive and mutually reinforcing ecosystem.

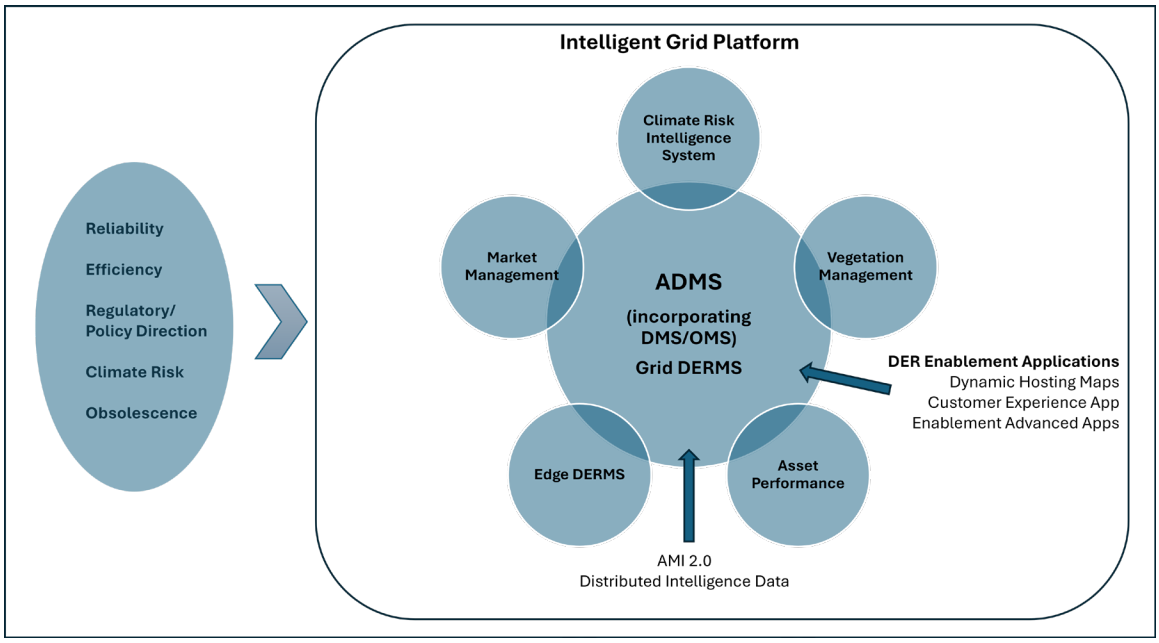


Figure 1: Intelligent Grid Platform End State

Collectively, the Intelligent Grid Platform enhances situational awareness, strengthens operational control, and enables more coordinated, data-driven decision-making across the distribution system. It supports improved reliability through faster fault detection and restoration, greater efficiency through optimized system operation and asset utilization, and expanded grid modernization capabilities through the effective integration and management of DERs and other grid-edge resources. This approach aligns with evolving regulatory direction, including OEB expectations related to DER integration, non-wires solutions, and the adoption of cost-effective, flexible grid modernization investments. It also responds to growing climate-related risks by improving Hydro One's ability to predict, prepare for, and respond to significant weather-related events. Further, it removes the risk of operating with unsupported ORMS and DMS. The investment leverages, integrates, and operationalizes data from related initiatives, including AMI 2.0 with DI (see DSP Section 3.11 D-SR 12, Figure 9, DI Applications), to address emerging system needs and maximize the value of complementary grid modernization investments.

The Intelligent Grid Platform represents a multi-year investment spanning the 2023–2027 and 2028–2032 investment periods. The capabilities are proposed to be implemented in a sequenced manner to support effective organizational change management and to

moderate the overall capital investment profile. Figure 2 below provides an overview of the planned timing of program elements spanning both investment periods.

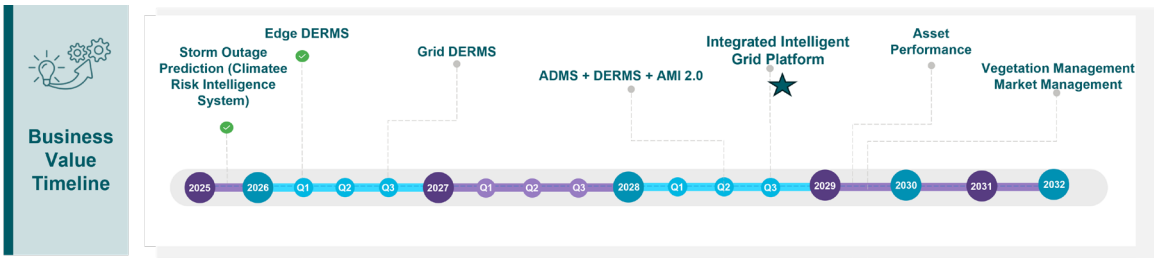


Figure 2: Intelligent Grid Platform Value Timeline: 2025-2032

This section of the Investment Summary Document is organized into two sub-sections. Sub-section 1 provides a description of Stage 1 investments (2025-2028) including foundational activities related to the design, build, and testing of the new ADMS in preparation for its implementation in 2028. Section 2 outlines the investments planned for the 2029–2032 period, which expand and enhance platform functionality to further address efficiency, reliability, and respond to public policy/regulatory needs.

3.1 STAGE 1 INVESTMENT DESCRIPTION 2025-2028

3.1.1 STAGE 1 SCOPE

Stage 1 investments in the 2023–2028 period will deliver the foundational capabilities required to enable the unified Intelligent Grid Platform planned for an in-service date of 2028. These investments include the upgrade of existing assets, implementation of new systems, and configuration of software-as-a-service (SaaS) solutions, with each component deployed in accordance with its lifecycle requirements and delivery model. More specifically, these investments include:

- Designing, building, and testing the new ADMS version 3.10 which incorporates the replacement and modernization of the former Outage Response Management System (ORMS v.6.5) and the Distribution Management System (DMS v.3.7) consolidating their capabilities within a single integrated platform.
- Configuring and operationalizing a SaaS Grid DERMS providing system-wide visibility, forecasting, optimization, and control of DERs. Operating at the control room level, it coordinates aggregated DER fleets to maintain reliability, manage

system constraints, and optimize performance across the distribution network. Through leveraging Grid DERMS with ADMS and SCADA, it ensures DER dispatch aligns with grid needs such as voltage regulation, load balancing, and congestion management;

- Configuring and operationalizing a new SaaS Edge DERMS introducing distributed intelligence and control at or near DERs—including smart inverters, EV chargers, microgrid controllers, and site-level or behind-the-meter (BTM) energy management systems—extending ADMS capabilities to the grid edge. It enables low-latency, autonomous decision-making to address real-time conditions such as voltage fluctuations and rapid load changes at the feeder, site, or device level, while coordinating both front-of-the-meter and BTM resources. Operating independently when needed, Edge DERMS ensures immediate responsiveness and supports local reliability.
- Edge DERMS and Grid DERMS are complementary, not duplicative. Grid DERMS manages system-wide optimization and coordination of aggregated DER flexibility, while Edge DERMS executes real-time, localized control of individual resources—including behind-the-meter assets—often aligning customer objectives with grid requirements. This layered architecture is critical as distribution systems evolve into dynamic, bidirectional networks with high DER penetration, combining centralized orchestration with fast local responsiveness to maintain reliability and enable a flexible and resilient distribution grid.
- Configuring and operationalizing a SaaS CRIS application that uses weather forecasts, asset condition data, and historical outage patterns to predict where and how the distribution system is likely to be impacted during weather and related events. It provides Hydro One's operations teams with forward-looking insight into probable damage locations, severity, and timing, enabling more informed and proactive decision-making before and during severe weather. From an operational standpoint, this capability improves both efficiency and effectiveness by shifting Hydro One from reactive response to proactive planning. It enables optimized crew staging, targeted resource allocation, and prioritization of high-risk assets and circuits, reducing unnecessary dispatches and accelerating restoration. During events, it enhances situational awareness across the control room and field,

supporting faster, more coordinated response actions and reducing overall outage duration and restoration costs.

- Placing the ADMS v.3.10 in service in 2028 and, later that year, integrating Grid DERMS, Edge DERMS, and CRIS, which were previously deployed and operated as stand-alone systems, to establish the Intelligent Grid Platform for full operational use.
- For operators and planners, the ADMS will provide a single, integrated platform that enables real-time visibility, coordinated system control, and the seamless use of shared data across capabilities, supporting more effective operations and more informed, efficient planning and investment decisions.
- Execution of a targeted change management program to support ADMS implementation, including stakeholder engagement, readiness activities, and role-based training for control room, field, and support staff, supported by updated procedures, job aids, and post-implementation stabilization.

Figure 3 provides a high-level overview of key planned activities for the implementation of the Intelligent Grid Platform from 2025 through 2028.

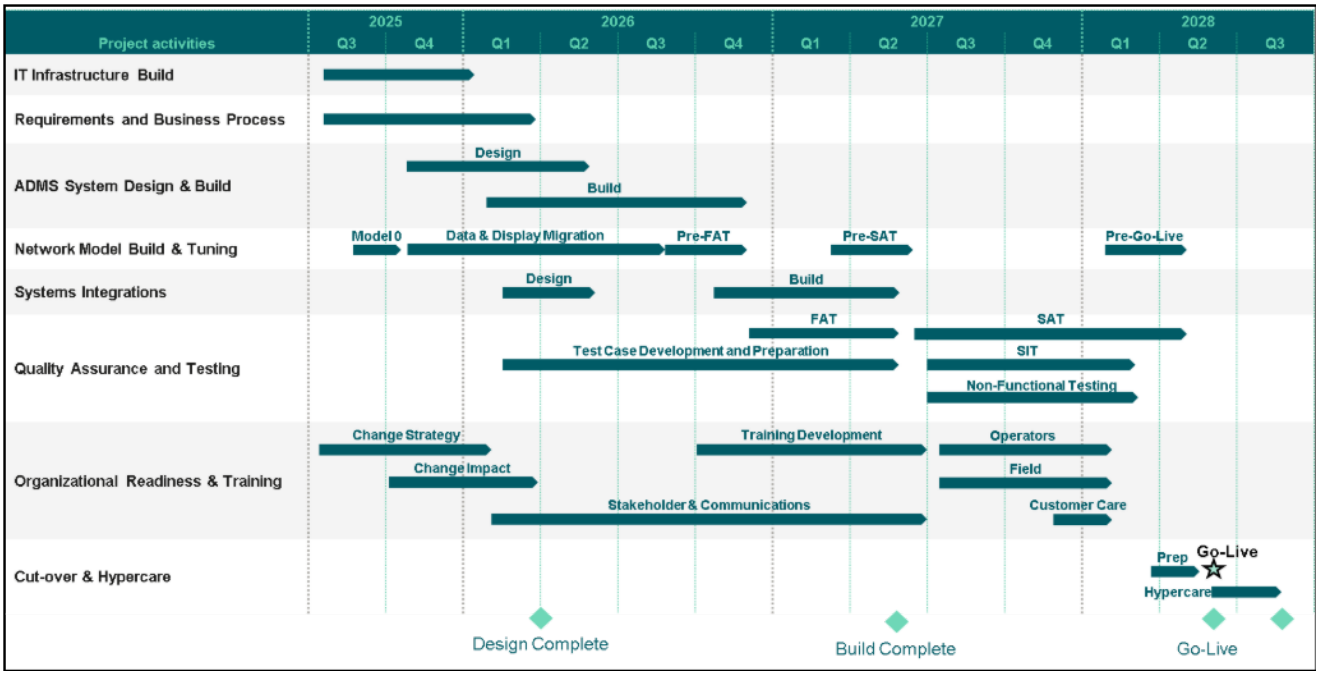


Figure 3: Intelligent Grid Platform Stage 1 Overview Schedule

3.1.2 STAGE 1: PROJECT APPROACH AND MANAGEMENT

The Intelligent Grid Platform follows Hydro One's formal five stage Governance Framework described in GSP Section 4.10.

3.2 STAGE 2: INTELLIGENT GRID PLATFORM INVESTMENT DESCRIPTION 2029-2032

Stage 2 investments follow the completion, in-service and operational stabilization of Stage 1 investments. This phased approach reduces operational risk by allowing foundational platform functionality, integration, business and technical processes to mature before introducing additional advanced capabilities. The sequencing also supports organizational change management, enabling distribution system operators, field and engineering staff, as well as support teams to adapt to new technology and business workflows while minimizing disruption to ongoing operations.

Stage 2 investments (2029-2032) fall into two categories: 1) addition of Intelligent Grid Platform capabilities to address needs; and 2) routine lifecycle updates to ADMS, Grid and Edge DERMS, and OMS components to ensure ongoing system performance.

3.2.1 PHASED ADDITION OF INTELLIGENT GRID PLATFORM CAPABILITIES

Over the 2028–2032 period, the following additional capabilities are to be integrated into the ADMS-based Intelligent Grid Platform:

- **Intelligent Vegetation Management (IVMS) Module:** Enhances operational awareness of vegetation-related risks across the distribution system by leveraging climate intelligence, geospatial data, and predictive analytics. By identifying and prioritizing high-risk vegetation threats, the capability supports more informed operational decision-making and improved reliability outcomes through reductions in outage frequency and duration. For example, IVMS can identify spans and circuits with elevated vegetation risk before an outage occurs, providing Operators with additional context when prioritizing operational actions. It can also support outage response and restoration efforts by highlighting likely vegetation-related causes and potential damage locations, enabling faster assessment and restoration activities. The data and risk insights generated by IVMS are also expected to inform the ongoing evolution of the OCP Flex vegetation management strategy (see DSP Section 3.2.3.5.2.2, Asset Condition under Rights of Way). Implementation is scheduled for Stage 2 to allow Hydro One to establish a stable ADMS operating environment and mature source-system integrations.
- **Asset Performance Module:** Integrates operational data, asset condition, and environmental factors to assess and predict distribution station-level transformers and poles asset health. By providing visibility into the condition and failure risk of critical assets, such as transformers, circuit breakers, and poles, the capability supports more informed operational decision-making, including switching, restoration, and contingency planning activities. It also enables more risk-based maintenance, repair, and replacement decisions, improving asset utilization and performance. This capability is strategically sequenced for Stage 2 to leverage the operational data, system integrations, and network models established through Stage 1. By building on these foundational capabilities, the module can deliver more mature and actionable asset health insights that support risk-based operational and asset management decisions. This sequencing also allows operational and asset management processes to evolve alongside the platform before advanced analytics capabilities are introduced.

- **Market Management Platform:** The market management platform enables Hydro One to coordinate DERs participation in the IESO-administered markets. This is aligned with the role of the "DER Coordinator" identified by the IESO's Enabling Resources Program (ERP) for LDCs.[3] The market management platform will allow Hydro One to evaluate safety and reliability of the distribution grid upon DER participation and coordinate dispatch signals while managing distribution system constraints and operating requirements. The Market Management Platform is planned for Stage 2 to align with the expected maturity of DER management capabilities, market participation frameworks, and regulatory requirements. Sequencing implementation after Stage 1 allows Hydro One to leverage foundational platform capabilities, reduce implementation risk, and align deployment with evolving market opportunities and industry practices.
- **Dynamic Hosting and Loading Capacity Maps:** Delivers customers with accurate, near real time information on DER connection feasibility. This reduces manual studies, improves transparency, and accelerates DER adoption. Without these maps, customers would rely on outdated data, increasing processing times and creating bottlenecks that limit scalable DER integration. This capability is strategically sequenced for Stage 2 to build upon the network model enhancements, system observability improvements, and DER and operational data integration established through Stage 1. This approach ensures the capability is supported by the data quality and operational maturity required to deliver value across operational and customer-facing use cases.
- **DER Connection Experience Application:** Streamlines and automates interconnection processes, enabling efficient management of increasing application volumes while maintaining customer service standards. Implementation is planned for Stage 2 to leverage the hosting capacity analysis, DER data integrations, and business processes established through preceding modernization initiatives. This sequencing supports a more seamless customer experience while minimizing the need for future redesign as DER-related capabilities continue to mature.

3 ERP Distributed Energy Resources Integration Project, Stakeholder Feedback and ESO Response, Transmission-Distribution Coordination Section, pg. 5, March 2026.

- **DER Enablement Advanced Applications:** Provides forecasting and optimization capabilities required to plan and operate NWSs at scale, improving operational agility and reducing reliance on manual processes. This capability is strategically sequenced for Stage 2 to build upon the foundational DER management, forecasting, monitoring, and control capabilities established through Stage 1. By leveraging mature operational processes, data, and system capabilities, Hydro One can more effectively deploy advanced DER optimization and grid management functions while enabling operational practices to evolve alongside increasing DER penetration and system complexity.

3.2.2 LIFECYCLE MANAGEMENT UPDATES

Lifecycle updates to the ADMS are required to maintain performance, vendor support, cybersecurity, and align with evolving operational and regulatory requirements. The ADMS currently being developed is based on Schneider Electric's ADMS 3.10 platform released in 2024. Consistent with standard enterprise technology lifecycle management updates will be required during the 2028–2032 period. Lifecycle updates will be coordinated across dependent capabilities to preserve interoperability and sustain the long-term value of the platform.

3.2.3 PROGRAM APPROACH AND MANAGEMENT

Stage 2 of the Intelligent Grid Project is planned to follow Hydro One’s formal five stage Governance Framework described in GSP Section 4.10.4.1.

4.0 OUTCOMES

The Intelligent Grid Portfolio seeks to maintain safety, improve reliability and efficiency, respond to evolving regulatory and climate-related requirements, and modernize critical legacy operational systems. These investments support OEB RRF outcome objectives as described in Table 1.

4.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the proposed investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF).

Table 1 - Outcome Summary

Customer Focus	• Provides more reliable and responsive electricity service through improved outage prevention and restoration. • Provides increased capability to locate and isolate faults, reducing customer interruption times. • Improves service reliability by proactively coordinating DERs to reduce outages and congestion impacts. • Improves local power quality and customer experience through faster localized response to voltage and load issues • Improves customer communication and outage preparedness. • Supports OCP flex forest management strategy. • Improves service reliability by identifying and mitigating asset failure risks before they impact customers. • Provides customers current information on DER connection feasibility thereby streamlining application process.
Operational Effectiveness	• Enables coordinated, data-driven decision-making across planning, operations, and field response. • Consolidates two separate network models (M-Class in DMS and F-Class in ORMS) into one sub-transmission and distribution model in the ADMS improving operator view of the entire distribution grid enabling more insights and improved decision making. • Enhances system-wide visibility and control of distributed resources, enabling optimized grid operations. • Enables low-latency, autonomous control at the feeder, site, and behind-the-meter level, reducing dependence on centralized intervention. • Enables proactive operational planning, including crew staging and resource allocation ahead of weather events. • Enables risk-based, data-driven prioritization of vegetation management activities. • Enhances asset lifecycle management through condition monitoring, predictive analytics, and targeted investment decisions. • Enhances distribution system reliability resulting from optimization of switching activities, voltage optimization, fault location, isolation, and service restoration. • Enables faster, data-driven decisions on how and when to deploy flexible capacity services, reducing manual analysis, streamlining operator workflows, and minimizing the need for reactive

	interventions or conservative over-building of traditional infrastructure.
Public Policy Responsiveness	• Supports transition to a modern, flexible, and decarbonized grid aligned with provincial policy objectives. • Supports DER integration and electrification, enabling the efficient use of existing grid infrastructure. • Empowers customer participation in energy systems while supporting grid stability and renewable integration. • Enhances resilience to extreme weather events, reducing societal disruption and supporting climate adaptation goals. • Supports public safety and improves system resilience in the face of increasing climate-related vegetation risks. • Promotes cost-effective infrastructure management and long-term system reliability. • Supports enablement of *Ontario's Integrated Energy Plan (2025), Framework for Energy Innovation: Setting the Path Forward for DER Integration (2023), and Non-Wires Solutions Guidelines for Electricity Distributors (2024).*
Financial Performance	• Improves cost efficiency of grid operations by enabling more proactive and predictive decision-making. • Optimizes capital investment by deferring or avoiding some traditional infrastructure upgrades through better utilization of existing grid capacity using DER flexibility. • Enhances productivity of field and operational resources through improved situational awareness, automation, and better prioritization of work activities. • Reduces costs associated with outages and service interruptions by improving prevention, response, and restoration capability. • Enables more efficient vegetation management • Improves storm response cost management through better forecasting, crew staging, and resource allocation. • Supports efficient integration of distributed energy resources by minimizing the need for incremental infrastructure investment.

5.0 EXPENDITURE PLAN

This section summarizes Hydro One's forecast expenditures of $31.7M in capital and $28.2M in prepaid cloud for the 2028-2032 period, and provides context relating to the 2023-2027 period investments, previously approved under EB-2021-0110. Table 2 below summarizes Hydro One's forecast net capital and prepaid expenditures for the 2028-2032 period.

Table 2 - Hydro One – Investment Expenditures

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	6.3	2.7	0.5	11.1	11.1	31.7
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**6.3**	**2.7**	**0.5**	**11.1**	**11.1**	**31.7**
Prepaid Expenditures Related to Cloud	**2.5**	**13.5**	**3.6**	**5.1**	**3.5**	**28.2**

For the 2028-2032 period, Hydro One forecasts a total of $31.7M in capital and $28.2M in prepaid expenditures. Table 3 summarizes Hydro One's net capital and prepaid expenditures, including planned and forecast expenditures for the 2023-2027 rate period and planned expenditures for the 2028-2032 rate period. These expenditures are presented according to the investments described in Section 3.0 Investment Description.

Table 3 - Hydro One - Expenditures Continuity Over Rate Period ($M)

Description	Capital Expenditures			Prepaid Cloud Expenditures		
	Plan[4] 23-27	Act/Fcst[5] 23-27	Total 28-32	Plan 23-27	Act/Fcst[5] 23-27	Total 28-32
DMS/ORMS	13.9[6]	0.0	0.0	0.0	0.0	0.0
ADMS[7]	0.0	39.8	28.0	0.0	0.6	5.5
Grid DERMS	0.0	0.0	0.0	0.0	0.0	2.5
Asset Performance module	0.0	0.0	1.5	0.0	0.0	0.0
Dynamic DER Hosting	0.0	0.0	0.0	0.0	0.0	3.0
DER Enablement	0.0	0.0	0.0	0.0	0.0	17.2
DER Connection Experience	0.0	0.0	2.2	0.0	0.0	0.0
Total	**13.9**	**39.8**	**31.7**	**0.0**	**0.6**	**28.2**

[4] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[5] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.
[6] Resides in G-GP-17 and G-GP-18 as Hydro One mapped some General Plant investments from the prior rate application to new ISDs in this rate application. See GSP Section 4.11
[7] This investment predominantly resides in Other Distribution investment (D-SS-Other) as Hydro One mapped some General Plant investments from the prior rate application to new ISDs in this rate application. See GSP Section 4.11

2023-2027 EXPENDITURES

The 2023-2027 OEB-approved settlement included GSP Section 4.11 G-GP-17 (DMS Upgrade) and GSP Section 4.11 G-GP-18 (ORMS Upgrade) with a combined post-settlement forecast expenditure of $13.9M. Following a reassessment of distribution system operating requirements, Hydro One determined that an integrated Intelligent Grid/ADMS platform represented a more prudent long-term solution than proceeding with standalone DMS and ORMS upgrades. Accordingly, planned GSP Section 4.11 G-GP-17 and GSP Section 4.11 G-GP-18 investments were discontinued and replaced with the Intelligent Grid/ADMS platform. Funds were reallocated to the Intelligent Grid/ADMS program, increasing planned investment to $39.8M in capital expenditures and $0.6M in prepaid cloud costs over the 2023-2027 period. The Intelligent Grid/ADMS solution consolidates distribution management and outage management capabilities within a single integrated platform, addressing identified obsolescence risks while supporting enhanced operational, outage response, and system planning capabilities.

2028-2032 EXPENDITURES

Most forecast capital expenditures in the 2028-2032 period are attributable to the ADMS ($28.0M) and consist of implementation activities associated with in-servicing the Intelligent Grid Platform in 2028 ($5.8M) and lifecycle management investments in 2031 and 2032 ($22.2M). The 2028 expenditure represents the culmination of design, configuration, integration, testing, and deployment activities undertaken during the 2023-2027 period and supports the planned 2028 in-service date of the ADMS, including DMS, OMS, and Grid DERMS and the integration of Edge DERMS and CRI systems. The remaining capital investments in 2031 and 2032 relate to lifecycle management upgrades to the ADMS platform required to maintain vendor support, system reliability, cybersecurity, and ongoing functionality.

Prepaid cloud expenditures in the 2028-2032 period are primarily associated with the DER enablement investments ($17.2M), followed by the ADMS enhancements ($5.5M), and DER Hosting and Capacity Mapping ($3.0M).

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

The status quo alternative reflects Hydro One's continued reliance on a collection of discrete, aging systems with limited integration, visibility, and advanced operational capabilities. Maintaining this approach would significantly impair Hydro One's ability to address existing and future needs.

Under this alternative, emerging technologies, equipment, and devices would be more difficult to accurately model due to fragmented systems and limited analytical capability. This lack of integration would reduce situational awareness for field crews and distribution operators, increasing the risk of unsafe operating conditions resulting from an incomplete or inaccurate understanding of real-time system status.

From a DER perspective, the status quo would leave Hydro One without the tools, visibility, and operational capabilities required to manage increasing DER penetration and growing grid complexity. It would also constrain the organization's ability to respond to policy direction related to electrification, grid modernization, and the integration of NWS.

At the grid edge, the absence of integrated advanced systems would limit Hydro One's ability to fully leverage AMI 2.0 data, including DI locational awareness, interval usage, voltage, event, and power quality information. Without the capability to integrate and operationalize this data, Hydro One would lack the visibility needed to effectively monitor DER behaviour, validate system conditions, and support operational decision-making. This would further constrain the utility's ability to manage bidirectional flows, optimize hosting capacity, and maintain safe and reliable operation of increasingly dynamic distribution feeders.

Hydro One's ability to enable DER participation in IESO-administered markets would be limited, as there would be no effective means to monitor, control, or validate the safe and reliable integration of DER assets. Similarly, the ability to meet regulatory expectations

related to NWS would be reduced, limiting flexibility to address future peak demand and increasing reliance on more costly traditional infrastructure investments.

Finally, maintaining the status quo would limit Hydro One's ability to support the province's strategic direction for a modern, resilient, and increasingly distributed electricity system, as current asset information and analytics capabilities are insufficient to enable the level of planning, optimization, and operational insight required. Given these material risks and limitations, the status quo alternative is not recommended.

ALTERNATIVE 2: LIMIT INVESTMENT TO DMS AND ORMS UPGRADES SOUGHT AND APPROVED IN EB-2021-0110

At the time of the OEB-approved settlement for the 2023-2027 period, the planned DMS upgrade was intended to update SCADA functionality. However, a limited incremental upgrade to the existing DMS would not provide the scalability or advanced capabilities required to address the efficiency, reliability, and public policy/regulatory needs presented in Section 2.0. An incremental approach to DMS enhancement would result in constrained and fragmented DER enablement, limiting Hydro One's ability to implement NWS, deliver meaningful customer outcomes, and effectively integrate and optimize DERs across the distribution system. It would therefore fall short of supporting a modern, flexible grid capable of responding to evolving system conditions. While this alternative may reduce near-term capital requirements, it does not support grid modernization objectives, set out in Ontario's Integrated Energy Plan. Deferral of capability in this area would drive continued reliance on traditional infrastructure investments, resulting in higher long-term costs to customers and reduced operational flexibility. A limited DMS upgrade would not provide the functionality necessary to support these policy objectives or enable the efficient evolution of the distribution system. Accordingly, this alternative is not recommended.

ALTERNATIVE 3: SLOWER PACED IMPLEMENTATION

Proceeding with the Intelligent Grid deployment at a significantly reduced pace would lower near-term expenditures; however, it would also delay the implementation of key Stage 2 capabilities that support Hydro One's long-term grid modernization objectives. While this alternative would address the immediate need to replace the existing ADMS

platform and mitigate technology obsolescence risks, it would postpone capabilities that have been deliberately sequenced to follow the deployment and stabilization of the foundational Intelligent Grid platform.

The proposed Stage 2 capabilities are designed to build upon the operational maturity, data quality improvements, integration framework, organizational readiness, and technical foundation established through Stage 1. Their sequencing reflects a phased implementation strategy that first establishes and stabilizes core ADMS functionality before introducing more advanced operational, planning, and decision-support capabilities. Delaying these investments would defer the associated business and customer benefits and Hydro One's ability to respond effectively to evolving system, customer, and regulatory requirements.

Delaying investment would also constrain the continued development of Intelligent Grid capabilities at a time when electricity demand, DER adoption, and system complexity are increasing. As the electricity system evolves, postponement would reduce operational readiness, limit Hydro One's ability to implement advanced grid management approaches, and increase the risk of higher future implementation costs. Given the multi-year effort required to configure, integrate, and operationalize Intelligent Grid capabilities, a reduced-pace deployment would diminish Hydro One's ability to cost-effectively address emerging system needs, including opportunities to deploy NWS. Accordingly, this alternative is not recommended, as it does not represent a prudent or cost-effective approach to delivering the capabilities required to support long-term system needs.

ALTERNATIVE 4: IMPLEMENTATION OF THE INTELLIGENT GRID PLATFORM PORTFOLIO (RECOMMENDED)

The proposed Intelligent Grid Platform is the recommended alternative. The integration of operational and planning functionalities, with ADMS at its core, provides material benefits in terms of reliability, efficiency, and effectiveness by enabling a unified and coordinated operating environment. Rather than operating as siloed systems with limited interoperability, the integrated platform establishes a single source of truth for network topology, asset status, and system conditions, supporting consistent, timely, and informed decision-making across the organization.

These integration-driven capabilities directly address the identified needs underpinning this investment. By improving the quality, availability, and coordination of system data, the platform enhances system reliability and situational awareness, enabling faster and more effective responses to outages and system events. At the same time, the platform reduces system silos and reliance on manual workarounds, improving operational efficiency and supporting more effective utilization of existing assets, thereby reducing costs and deferring incremental infrastructure investment where feasible. Further, the integrated architecture provides the foundation required to support evolving regulatory and policy objectives, including the scalable integration of DERs and the implementation of non-wires solutions.

The platform also addresses climate related risks and system obsolescence by integrating weather, asset, and real-time system data to support more proactive storm response and efficient restoration, while modernizing legacy systems to reduce operational risk and improve long-term maintainability.

Accordingly, the proposed Intelligent Grid Platform is the preferred alternative. It most effectively addresses the identified reliability, operational efficiency, regulatory and policy needs while supporting the long-term sustainability of the distribution system through the benefits of an integrated operating environment.

7.0 EXECUTION RISK AND MITIGATION

Table 4 below summarizes execution risks and mitigations for these investments.

Table 4 - Execution Risks and Mitigations

Executing Risk	Mitigating Action
Operational disruption during cutover **Risk:** Transitioning to the new ADMS system could impact real-time grid operations or system availability.	Cutover during low-risk operating windows. Detailed roll-back procedures tested in advance. Operators' involvement in rehearsals and dry-runs
Data Migration Errors (Models, Telemetry, Historical Data) **Risk:** Incorrect or incomplete migration of network models, telemetry data, or historical data may affect system accuracy and decision-making.	Automated data validation and reconciliation scripts. Side-by-side comparison of state estimation and power flow results. Freeze periods for model changes prior to migration
Insufficient operator and field personnel readiness and adoption **Risk:** Operators and field personnel may not be fully comfortable with the new ADMS interface, workflows, or tools, increasing operational risk post-go-live.	Early and continuous operator and field personnel engagement. Role-based training using real operational scenarios. Simulator-based training prior to production use. Extended hyper-care with on-site vendor supervision.
Integration failures with external systems **Risk:** Interfaces with external systems may not function as expected	Early definition of interface contracts and data ownership. End-to-end integration testing in a production environment.
Cyber security vulnerabilities introduced during transition **Risk:** Temporary configurations, parallel environments, or new integrations may introduce security vulnerabilities.	Penetration testing and vulnerability scans before go-live. Principle of least privilege applied from day one. Security Office sign off as a formal go-live gate.
Schedule delays due to Scope Change **Risk:** Additional requirements discovered during implementation can extend timelines and increase cost.	Clearly defined scope baseline with formal change control. Separation of must-have features vs post-go-live enhancements. Strong product and project management.
Vendor dependency and knowledge concentration	Knowledge transfer embedded into the contract. Comprehensive documentation requirements.

Executing Risk	Mitigating Action
Risk: Over-reliance on the vendor during implementation may limit internal capabilities and long-term sustainability.	Internal capability development plan before project closing.
Performance or Scalability issues under peak conditions **Risk**: The new ADMS may not perform as expected under peak conditions, high telemetry volume or contingency scenarios. .	Stress and performance testing using the worst-case scenarios. Scalability testing aligned with future grid growth assumptions. Hardware and infrastructure sizing with growth buffers. Clear performance acceptance criteria
Vendors' internal issues (i.e., resource availability) **Risk:** Unforeseen issues on the vendor side (i.e., resources availability, delayed training).	Strong project management, regular touchpoints with PM counterparts and steering committee meetings. Contractual strength to keep vendor accountable for the project performance including built in penalties.
Organizational Change Management **Risk:** The volume and pace of organizational change may cause a lack of employee engagement and user adoption, leading to a negative impact on employee performance and morale	The project will ensure a comprehensive Change Management & Training Plan is defined and implemented. The project has secured a professional services vendor to assist and manage the overall change management and training in collaboration with a full-time Hydro One change lead.

D-SS-10	REAL TIME DISTRIBUTION STATION AND FEEDER MONITORING PROGRAM
Primary Trigger:	Reliability
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	5.3	5.4	5.5	5.7	5.8	27.7
Orillia RZ	0.00	0.00	0.00	Embedded in Hydro One Networks		
Peterborough RZ	0.00	0.00	0.00			

Summary:

The Real Time Distribution Station and Feeder Monitoring Program will deploy 340 Feeder Monitoring Sensors (FMSs) across the distribution system between 2028 and 2032. The investment provides continuous, real-time visibility of voltage, current, loading, and direction of power flow at targeted higher-utilization stations and feeders where this information is currently unavailable. This investment will improve system visibility to support reliable distribution system operations, Non-Wires Solution (NWS) implementation and flexible connections.

There are no planned capital expenditures for Orillia RZ or Peterborough RZ.

1.0 INVESTMENT NEED

Hydro One operates more than 1,000 Distribution Stations (DSs) and Regulating Stations and over 3,300 distribution feeders across its service territory. Currently, only 90 DSs and approximately 800 feeders are monitored in real time. Consequently, across much of the distribution system, Hydro One does not have continuous visibility of operating conditions, including voltage, current, loading, power factor, and direction of power flow.

Hydro One's distribution system has been developed over several decades, during which real-time monitoring was not practical to deploy broadly due to the cost and availability of communications and monitoring technologies. Advances in telecommunications infrastructure, including expanded cellular network coverage, together with the availability of lower-cost monitoring devices, have made real-time monitoring a practical and scalable option across the distribution system.

At the same time, distribution system operating conditions are becoming more dynamic as a result of load growth, including electrification, Distributed Energy Resource (DER) adoption, and increased use of capacity-enabling solutions such as NWS and flexible connections. These developments increase the need for continuous information on actual local system conditions.

This investment provides real-time visibility of higher-utilization portions of the distribution system where this information is currently unavailable. Continuous operational information will improve situational awareness and provide system operators with additional information to support load transfers, system configuration changes, and the management of changing operating conditions while maintaining reliability and power quality.

The investment will also support other applications such as NWS and flexible connections. For NWS, real-time feeder and station information can be used to assess loading conditions, inform dispatch requirements, and measure NWS performance at monitored locations. For flexible load and DER connections, improved visibility of local system conditions will support the operational and planning assessments required to manage these arrangements.

2.0 INVESTMENT DESCRIPTION

The proposed investment will deploy approximately 340 Feeder Monitoring Sensors (FMSs) across Hydro One's distribution network between 2028 and 2032, with an average installation rate of 68 devices per year.

FMSs are pole-mounted monitoring devices that provide continuous, SCADA-grade measurement of key electrical parameters, including voltage and current, at distribution station ingress and feeder egress. The FMSs will collect and communicate real-time operational data, providing Hydro One with year-round (8,760-hour) visibility into the performance and loading characteristics of distribution assets. Data from the FMSs will be integrated into Hydro One's Advanced Distribution Management System (ADMS) for use by system operators and other functions.

Hydro One will prioritize deployment to distribution stations and feeders operating at or above 80% of their Planned Loading Limit (PLL). This investment expands monitoring beyond only the most highly utilized assets, while avoiding broad deployment across portions of the distribution system with greater remaining load margin. Higher-utilization assets have less remaining loading margin and therefore can derive greater operational value from enhanced visibility of actual system conditions. These locations may also be more likely to require considerations of NWS, flexible connections, or future infrastructure investments as system needs evolve. In this manner, the proposed scope concentrates expenditures on locations where the additional monitoring capability is expected to provide greater operational value.

3.0 OUTCOMES

The outcome of this investment will be improved real-time observability of higher-utilization distribution stations and feeders where continuous operating information is not currently available. The proposed FMS deployment will provide Hydro One with continuous information on voltage, current, loading, power factor, and direction of power flow at approximately 340 targeted station and feeder monitoring locations.

Collectively, the investment will improve Hydro One's ability to observe and operate its distribution system, support more flexible use of available system capability, and make

better-informed operational decisions while maintaining reliability and power quality as distribution system needs evolve.

3.1 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	• Support reliable service and power quality for customers by providing operators with real-time visibility to inform load transfers, system reconfiguration, and the management of changing operating conditions.
Operational Effectiveness	• Improve system flexibility by supporting load transfers, system configuration changes, and the management of changing system conditions. • Enable additional system capacity by supporting the implementation of Non-Wires Solutions, and flexible connections for load and generation customers.

4.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's planned net capital expenditures for Hydro One in the 2028-2032 rate period. Over the 2023-2027 rate period, Hydro One forecasts expenditures for this investment to be nil. There are no planned expenditures in Orillia RZ and Peterborough RZ.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	Plan[2] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	-	6.1	6.2	6.3	6.4	6.6	31.5
Less Removals	-	0.7	0.7	0.8	0.8	0.8	3.8
Less Capital Contributions	-	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**-**	**5.3**	**5.4**	**5.5**	**5.7**	**5.8**	**27.7**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

2023-2027 EXPENDITURES

This is a new program and there were no expenditures during the 2023-2027 period.

2028-2032 EXPENDITURES

Over the 2028-2032 rate period, forecast expenditures are $27.7M.

The forecast is based on an average unit cost comprised of procurement, programming, installation, and connection of FMS to the Advanced Distribution Management System. The factors influencing the cost of the investment include:

- Material costs for sensors, control cabinet and telecom equipment
- Labour costs to install these devices on existing or new pole
- Wireless signal availability and strength, which can impact location of device installation and the need for additional telecom equipment such as local antennas
- Cost to integrate new units into the Advanced Distribution Management System

Table 3 summarizes Hydro One's planned monitoring device installation per year.

Table 3 - Hydro One – Monitoring Devices

	2028	2029	2030	2031	2032	Total 28-32
Number of FMS unit installations	68	68	68	68	68	340

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the recommended option.

ALTERNATIVE 1: DO NOTHING

Under this alternative, Hydro One would continue to rely on existing monitoring systems and discrete current measurements. This option would not provide continuous, SCADA-grade visibility in areas where this information is not currently available. As a result, the benefits associated with improved system visibility to support distribution system operations, NWS implementation and flexible connections would not be realized under this alternative. Accordingly, this alternative was not recommended.

ALTERNATIVE 2: REDUCE THE NUMBER OF MONITORING DEVICE INSTALLATIONS TO 240 UNITS

Under this alternative, Hydro One would deploy approximately 240 FMSs over the forecast period, based on the forecast number of distribution stations and feeders operating above 90% of their PLL. While this option would provide enhanced visibility for the highest-loaded assets, it would reduce Hydro One's ability to monitor emerging constraints on assets operating between 80% and 90% of their PLL. As a result, the benefits associated with improved system visibility to support distribution system operations, NWS implementation and flexible connections would be lower than those achieved under the recommended alternative.

This alternative was not selected as the reduced scope would provide a lower level of monitoring coverage across the higher-utilization portion of the distribution system.

ALTERNATIVE 3: INSTALL 340 MONITORING DEVICES (RECOMMENDED)

Under this recommended alternative, Hydro One will install 340 Feeder Monitoring Sensors during the 2028-2032 planning period, targeting distribution stations and feeders operating at or above 80% of their PLL. The recommended alternative provides broader monitoring coverage of higher-utilization assets than Alternative 2 while maintaining a targeted deployment. The additional real-time information will support system operations, reliability and power quality, NWS implementations and evaluation, flexible load and DER connections, and distribution system assessments.

Hydro One considers the 80% PLL threshold to provide an appropriate balance between improving visibility of higher-utilization assets and limiting investments in monitoring assets with greater remaining loading margin.

ALTERNATIVE 4: UPGRADE HYDRO ONE DISTRIBUTION STATIONS WITH SCADA

Under this alternative, Hydro One would obtain additional real-time station-level monitoring through upgrades to the existing station metering, control, communication and SCADA infrastructure. Implementation would require more extensive station infrastructure upgrades and greater project complexity than the proposed FMS solution. Hydro One

estimates that providing the required station monitoring capability through SCADA upgrades would cost significantly more than the corresponding FMS solution.

The proposed FMS solution therefore provides a more scalable and lower-cost approach to obtaining the required monitoring capability at both station and feeder locations. Accordingly, Hydro One did not select this alternative.

6.0 EXECUTION RISK AND MITIGATION

While the proposed solution leverages commercially available monitoring technology and established communications networks, several factors may affect program execution.

The primary execution risk is equipment availability for sensors on the 44 kV system, as a limited number of vendors provide distribution monitoring sensors compatible at this voltage. Hydro One will mitigate this risk by undertaking a rigorous procurement process with sufficient lead time to secure equipment in advance of installation activities. Where appropriate, deployment may be prioritized to 27.6 kV and lower-voltage distribution feeders, where multiple standard monitoring solutions are commercially available. For portions of the 44 kV system where suitable high-side equipment is unavailable, Hydro One may deploy monitoring on the lower-voltage side of the station to obtain the required operational visibility.

Field installation schedules may be affected by seasonal access restrictions, adverse weather conditions, resource availability during the planning, design, and construction phases, and planned outage availability. To mitigate the installation risks, Hydro One will conduct comprehensive planning, scheduling, and coordination across internal business units and external stakeholders. To mitigate the risk of outage unavailability, work will be coordinated with planned outages to minimize customer impacts and maximize construction efficiency.

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