Transmission System Plan (TSP)

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SECTION 2.0 – TRANSMISSION SYSTEM PLAN

2.0.1 FILING REQUIREMENTS

Hydro One Networks Inc. (Hydro One) has prepared a five-year Transmission System Plan (TSP) for the 2028–2032 planning period. This TSP has been developed in accordance with the relevant requirements of Chapter 2 (Revenue Requirement Applications) of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission Applications, issued on October 30, 2025, with further guidance from Chapter 5 (Consolidated Distribution System Plan Filing Requirements), issued on December 16, 2025 (collectively, the Transmission Filing Requirements).

Hydro One Sault Ste. Marie LP (HOSSM) has prepared a consolidated six-year transmission system plan covering 2027–2032. The HOSSM system plan has also been prepared in accordance with the Transmission Filing Requirements. The six-year planning horizon is provided to align with the conclusion of HOSSM's deferred rebasing period in 2026, as established by the OEB. Additional information on HOSSM's Transmission System Plan is presented in TSP Section 2.10.

The TSP provides a consolidated set of documentation concerning Hydro One Transmission'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 transmission system. It sets out Hydro One's proposed transmission investments for the 2028–2032 period in the context of asset condition, transmission 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 Transmission's General Plant assets is presented in the General Plant System Plan (GSP) framework, included in Section 4.0 of the System Plans.

2.0.2 FORMAT OF THE TSP

Consistent with the Transmission Filing Requirements, this TSP is structured to first present the analytical foundation for the proposed capital plan, including asset condition, lifecycle strategies, benchmarking, and reliability performance (Sections 2.2 through 2.7), followed by the presentation of the capital investment plan and supporting expenditure trends and variance analysis (Sections 2.8 and 2.9). Subsequent sections address capital work execution and supporting investment documentation. Table 1 outlines the structure of the TSP.

Table 1 - TSP Structure

TSP Section	Content Description
Section 2.1	**TSP Overview** – This section provides an overview of Hydro One's transmission system, the factors that were considered in developing the investment plan, and a summary of the investment plan.
Section 2.2	**TSP Asset Information and Lifecycle Strategies** – This section presents the state of Hydro One's power system assets and their asset management and lifecycle strategies.
Section 2.3	**TSP Benchmarking and Other Studies** – This section presents the external studies that have been undertaken to inform the investment plan.
Section 2.4	**TSP Transmission System Reliability** – This section presents information related to transmission system reliability, including a discussion of transmission reliability performance and the reliability of delivery points serving First Nation communities.
Section 2.5	**TSP Performance Measurement and Outcomes** – This section presents Hydro One's approach to performance measurement, including a discussion of the transmission scorecard.
Section 2.6	**TSP Other Capital Planning Factors and Considerations** – This section details other factors that have informed the investment plan, including customer engagement and statutory and regulatory obligations.
Section 2.7	**TSP Investment Planning Process** – This section summarizes the information found in SPF Section 1.7 – Investment Planning Process related to Hydro One Transmission.
Section 2.8	**TSP Capital Expenditures – Overview** – This section presents Hydro One's capital investment plan for its transmission system for the 2028–2032 planning period.

Section 2.9	**TSP Capital Expenditure Variances** – This section compares Hydro One's historical capital spending with previous OEB-approved funding and provides a ten-year view (2023–2032) of Hydro One's capital spending for its Transmission Business.
Section 2.10	**HOSSM Capital System Plan** – This section presents HOSSM's 2027–2032 transmission capital investment plan, the factors and processes that informed the plan, forecast capital expenditures and material investments, and historical capital spending and variances.
Section 2.11	**TSP Capital Work Execution Strategy** – This section discusses the capital delivery process and Hydro One's approach to delivering the proposed capital investment plan.
Section 2.12	**TSP Material Investment Summary Documents** – This section includes detailed summaries of large investments (with forecast spending over $4M in any given year) over the 2028–2032 planning period in the OEB's System Access, System Service and System Renewal investment categories.

Hydro One has prepared the Table of Concordance in Appendix A to assist parties in reviewing the TSP. The table aligns the sections of this TSP with the Transmission Filing Requirements.

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

APPENDIX A – TABLE OF CONCORDANCE

Hydro One Reference	OEB Filing Requirements
2.0 Transmission System Plan	Ch. 5.0; Ch. 5.2; Ch. 2.4.1
2.1 TSP – Overview	Ch. 5.2.1; Ch. 2.4.1
2.1.1 Introduction	Ch. 5.2.1; Ch. 2.3.2
2.1.2 Transmission System and Service Area	Ch. 5.3.2; Ch. 2.3.2
2.1.3 Proposed TSP Investments	Ch. 5.2.1; Ch. 5.4; Ch. 5.4.1; Ch. 5.4.2; Ch. 2.4.1
2.1.4 The TSP is Reasonable and Appropriate	Ch. 5.2.1; Ch. 5.3.2; Ch. 5.4; Ch. 5.4.2; Ch. 2.4.1; Ch. 2.4.2; Ch. 2.4.4
2.2 TSP Asset Information and Lifecycle Strategies	Ch. 5.3.2; Ch. 5.3.3; Ch. 2.4.2
2.2.1 Introduction	Ch. 5.3; Ch. 2.4.2
2.2.2 Asset Component Information – Transmission Stations	Ch. 5.3.2; Ch. 2.4.2
Asset Description/Purpose	Ch. 5.3.2; Ch. 2.4.2
Asset Demographics, Condition and Other Factors	Ch. 5.3.2; Ch. 2.4.2
Asset Life Cycle	Ch. 5.3.3; Ch. 2.4.2
2.2.3 Asset Component Information – Other Station Components	Ch. 5.3.2; Ch. 2.4.2
Asset Description/Purpose	Ch. 5.3.2; Ch. 2.4.2
Asset Demographics, Condition and Other Factors	Ch. 5.3.2; Ch. 2.4.2
Asset Life Cycle	Ch. 5.3.3; Ch. 2.4.2
2.2.4 Asset Component Information – Transmission Lines	Ch. 5.3.2; Ch. 2.4.2
Asset Description/Purpose	Ch. 5.3.2; Ch. 2.4.2
Asset Demographics, Condition and Other Factors	Ch. 5.3.2; Ch. 2.4.2
Asset Life Cycle	Ch. 5.3.3; Ch. 2.4.2
2.2.5 Asset Component Information – Other Lines Assets	Ch. 5.3.2; Ch. 2.4.2
Asset Description/Purpose	Ch. 5.3.2; Ch. 2.4.2
Asset Demographics, Condition and Other Factors	Ch. 5.3.2; Ch. 2.4.2
Asset Life Cycle	Ch. 5.3.3; Ch. 2.4.2
2.3 TSP Benchmarking and Other Studies	Ch. 5.4.2; Ch. 2.4.4; Ch. 2.8.1
2.3.1 Introduction	Ch. 5.4.2; Ch. 2.4.4; Ch. 2.8.1
2.3.2 Summary of Studies and Findings	Ch. 5.4.2; Ch. 2.4.4; Ch. 2.8.1
2.3.3 Attachments: Studies	Ch. 5.4.2; Ch. 2.4.4; Ch. 2.8.1
2.4 TSP Transmission System Reliability	Ch. 5.2.3.2; Ch. 5.3.2; Ch. 2.6.2
2.4.1 Introduction	Ch. 5.2.3.2; Ch. 2.6.2

2.4.2 Transmission Asset Categories and Reliability Performance	Ch. 5.2.3.2; Ch. 5.3.2; Ch. 2.6.2
2.4.3 Transmission Asset Category Expenditures	Ch. 5.2.3.2; Ch. 5.4.1; Ch. 2.6.2
2.4.4 Reliability Measures and Standards	Ch. 5.2.3; Ch. 5.2.3.2; Ch. 2.6.2
2.4.5 Delivery Point Performance Outliers	Ch. 5.2.3.2; Ch. 2.6.2
2.5 TSP Performance Measurement and Outcomes	Ch. 5.2.3; Ch. 5.2.3.1; Ch. 2.6; Ch. 2.6.1
2.5.1 Introduction	Ch. 5.2.3; Ch. 5.2.3.1; Ch. 2.6
2.5.2 Transmission Scorecard	Ch. 5.2.3; Ch. 5.2.3.1; Ch. 2.6.1
2.6 TSP Other Capital Planning Factors and Considerations	Ch. 5.2.2; Ch. 5.3.1; Ch. 5.4.2; Ch. 2.3; Ch. 2.4
2.6.1 Introduction	Ch. 5.2.2; Ch. 5.3.1; Ch. 5.4.2; Ch. 2.3; Ch. 2.4
2.6.2 Customer Engagement	Ch. 5.2.2; Ch. 5.4; Ch. 2.3.2; Ch. 2.3.3
2.6.3 Additional Planning and Regulatory Considerations	Ch. 5.2.2; Ch. 5.3.1; Ch. 5.4.2; Ch. 2.3.2; Ch. 2.4.4
2.7 TSP Investment Planning Process	Ch. 5.3; Ch. 5.3.1; Ch. 2.4.1; Ch. 2.4.2; Ch. 2.4.4
2.7.1 System Planning Process Phases	Ch. 5.3.1; Ch. 2.4.2
2.7.2 Strategy and Context	Ch. 5.3.1; Ch. 5.2.1; Ch. 2.4.1; Ch. 2.4.2
2.7.3 Asset Management Process	Ch. 5.3; Ch. 5.3.1; Ch. 5.4; Ch. 2.4.2
2.7.4 Investment Planning Process	Ch. 5.3.1; Ch. 5.4; Ch. 5.2.1; Ch. 5.4.2; Ch. 2.3.2; Ch. 2.4.1; Ch. 2.4.2; Ch. 2.4.4
2.8 TSP Capital Expenditures – Overview	Ch. 5.4; Ch. 5.4.1; Ch. 5.4.2; Ch. 2.4.4
2.8.1 Introduction	Ch. 5.4.1; Ch. 5.4.2; Ch. 5.4.3.1; Ch. 2.4.4
2.8.2 System Overview	Ch. 5.4.1; Ch. 5.4.2; Ch. 5.4.3.1; Ch. 2.4.4
2.8.3 System Access	Ch. 5.1.2; Ch. 5.4.1; Ch. 5.4.2; Ch. 5.4.3.1; Ch. 2.4.4
2.8.4 System Renewal	Ch. 5.1.2; Ch. 5.3.3; Ch. 5.4.1; Ch. 5.4.2; Ch. 5.4.3.1; Ch. 2.4.4
2.8.5 System Service	Ch. 5.1.2; Ch. 5.4.1; Ch. 5.4.2; Ch. 5.4.3.1; Ch. 2.4.4
2.8.6 Impact of Capital Investment on OM&A	Ch. 5.4.1; Ch. 5.4.2; Ch. 5.4.3.1; Ch. 2.4.4.1
2.9 TSP Capital Expenditure Variances	Ch. 5.4.1; Ch. 2.4.4
2.9.1 Introduction	Ch. 5.4.1; Ch. 5.4.2; Ch. 2.4.4

2.9.2 Historical Capital Expenditures Trends and Variances	Ch. 5.4.1; Ch. 5.4.2; Ch. 2.4.4
Attachments: Capital Accomplishments and Variances, Transmission Capital Performance Reports	Ch. 5.4.1; Ch. 2.4.4
2.10 HOSSM Capital System Plan	Ch. 5.2; Ch. 5.3; Ch. 5.4; Ch. 2.4
2.10.1 Introduction	Ch. 5.2.1; Ch. 2.4.1
2.10.2 HOSSM System Plan Overview	Ch. 5.2.1; Ch. 5.3.2; Ch. 2.3.1; Ch. 2.4.1
2.10.3 Transmission Assets	Ch. 5.3; Ch. 5.3.2; Ch. 5.3.3; Ch. 2.4.2
2.10.4 Benchmarking and Other Studies	Ch. 5.4.2; Ch. 2.4.4; Ch. 2.8.1
2.10.5 Transmission System Reliability	Ch. 5.2.3; Ch. 5.2.3.2; Ch. 5.3.2; Ch. 2.6.2
2.10.6 Performance Measurement and Outcomes	Ch. 5.2.3; Ch. 2.6; Ch. 2.6.1, Ch. 2.3.5
2.10.7 Other Capital Planning Factors and Considerations	Ch. 5.2.2; Ch. 5.4; Ch. 5.3.1; Ch. 5.4.2; Ch. 2.3; Ch. 2.3.1; Ch. 2.3.3; Ch. 2.4; Ch. 2.4.4
2.10.8 Investment Planning Process	Ch. 5.3.1; Ch. 5.4; Ch. 5.2.1; Ch. 5.4.2; Ch. 2.3.1; Ch. 2.4.2.1
2.10.9 Capital Expenditures and Trends	Ch. 5.2.1; Ch. 5.2.3; Ch. 5.4; Ch. 5.4.1; Ch. 5.4.2; Ch. 5.4.3.1; Ch. 2.3.1; Ch. 2.4.3; Ch. 2.4.4; Ch. 2.4.4.1
2.10.10 Historical Capital Expenditure Variances	Ch. 5.4.1; Ch. 5.4.2; Ch. 5.4.2.1; Ch. 2.4.3; Ch. 2.4.4
2.10.11 Capital Work Execution	Ch. 5.4.2; Ch. 2.4.4
2.10.12 Material Investment Summary Documents	Ch. 5.4.3.2; Ch. 2.4.4
Attachments: Appendix 2-AA, 2-AB, Scorecard, Appendix 2-G	Ch. 2.1, Ch. 2.6.1
2.11 Capital Work Execution Strategy	Ch. 5.4.2; Ch. 2.4.4
2.12 Material Investment Summary Documents	Ch. 5.4.2.1; Ch. 2.4.4

SECTION 2.1 – TSP – OVERVIEW

2.1.1 INTRODUCTION

Hydro One Networks Inc. (Hydro One) and Hydro One Sault Ste. Marie LP (HOSSM) have prepared comprehensive Transmission System Plans (collectively, the TSP) covering the 2028-2032 and 2027-2032 periods, respectively.[1] The TSP presents a portfolio of capital investments that have been prioritized based on an outcomes-driven and customer-focused investment planning framework, in alignment with the principles and expectations articulated by the OEB in its *Renewed Regulatory Framework* (RRF).[2] The portfolio of capital investments from HOSSM is set out in greater detail in Exhibit B-2-1, Section 2.10. The remainder of Section 2.1 relates only to the TSP related to Hydro One.

Hydro One's transmission grid is the backbone of Ontario's electricity system, serving 34 local distribution companies (LDCs), 88 large direct-connected customers, and 139 generators (including nuclear and hydroelectric). Hydro One strives to provide safe and reliable grid operations on a 24 hours a day, seven days a week basis and accommodate load and generation growth. At the same time, the company must invest in transmission assets as required to enable Ontario's broader electricity system plans, resulting in significant increase in nondiscretionary spending. To meet these objectives over the 2028-2032 period, Hydro One plans to invest an average of $3,330.5M per year in Transmission capital, for a total of $16,652.4M.

The proposed capital plan for the 2028–2032 period reflects a fundamental change relative to the prior TSP. This change is driven by unprecedented increases in mandatory investments to address regional and bulk system planning across Ontario, as well as growing customer connection requirements. As a result, System Access and System

[1] Historical Years 2023 to 2027 for Hydro One and 2016 to 2026 for HOSSM. As a co-applicant, HOSSM has prepared a consolidated six-year Transmission System Plan covering the 2027-2032 period. The six-year planning horizon aligns with the conclusion of HOSSM's deferred rebasing period in 2026, as established by the OEB.

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

Service investments collectively account for approximately 50% of the expenditures in this TSP, compared to just over 10% of the approved amounts for the prior period.[3] At the same time, Hydro One must continue investing to renew the existing transmission system during this period of increasing demand.

Relative to approved capital expenditures for 2023-2027, non-discretionary investments in System Access and System Service increase by $1,317M and $6,157M respectively, representing relative increases of 422% and 1268%. While System Renewal remains the largest investment category, System Renewal investments increase by only $1,287M, or 22% relative to the approved 2023-2027 plan. However, System Renewal's share of the portfolio declines from approximately 85% of the approved 2023-2027 plan to 43% of the proposed 2028-2032 plan.[4] Total capital expenditures are increasing by $9,775M or 142% relative to the approved 2023-2027 plan, with approximately 76% of that increase attributable to higher non-discretionary System Access and System Service investment levels relative to the approved 2023-2027 plan. For System Access, the distinction between gross and net capital expenditures is material because a substantial portion of the expenditures is recoverable through customer contributions. Gross System Access capital expenditures are approximately $3,561.8M, while the net capital attributable to System Access over the 2028-2032 period is approximately $1,628.8M. However, even on a net basis, this amount is more than five times the approved 2023-2027 level.

The shift in overall spending toward nondiscretionary, system-planning transmission projects continues a trend that began during the 2023-2027 period, during which actual and forecast levels of System Access and System Service investments increased by $464.0M or 148% and $1,396.0M and 287% respectively relative to approved levels. Faced with this material increase in non-discretionary investment, after recording amounts in the Externally Driven Work Account (EDWA) and efforts to reprioritize investments to enable non-discretionary investment, Hydro One is projected to exceed the total approved capital envelope for 2023-2027 by $1,640.0M or 24.0%. However, substantially all of this

[3] System Access and System Service investments comprise 49.7% of the proposed 2028-2032 portfolio, compared to 11.1% in the approved 2023-2027 plan.
[4] System Renewal represents 42.6% of the proposed 2028-2032 plan.

variance is attributable to externally driven work and is expected to be recorded in the account. Excluding EDWA-eligible work, Hydro One's cumulative transmission capital expenditures are forecast to exceed the OEB-approved capital envelope by only $24.4M, or 0.4%. This demonstrates that, despite the material increase in non-discretionary investment, Hydro One's reprioritization efforts kept expenditures excluding EDWA-eligible work closely aligned with the 2023-2027 OEB-approved capital envelope.

Looking forward, Hydro One's proposed 2028-2032 TSP is shaped by three key drivers:

- System Service: As a result of ongoing, IESO-led regional planning, bulk system planning studies, and resource procurement, significant investments are needed to address regional needs, maintain broader system capability, ensure local supply adequacy, enable new generation connections, and accommodate load growth. These largely non-discretionary investments are required to maintain compliance with planning and reliability criteria and to implement planning outcomes. Notably, the unprecedented growth expected over the next 25 years has led the IESO to identify a series of transmission reinforcements over the next seven years, including in the Northeast, Southwest, Northwest, and GTA; these investments are reflected in T-SS-09 (West of London Reinforcements), T-SS-11 (Bulk Planning) and T-SS-12 (Regional Planning). Combined, bulk and regional planning triggered work is estimated to increase system transfer capability by more than 10,000 MW and enable more than 2,500 MW of new generation capacity province-wide.

- System Access: Increasing demand for customer connections, estimated at more than 6,000 MW of capacity enablement within the rate period, reflects a material increase in requests for new and expanded load connections from LDCs, industrial customers, and large commercial loads. The scale of this activity represents a step-change from the amounts forecast in the prior TSP, reflected in both the volume and complexity of enabling these connections. The increase reflects not only a greater number of customer connection requests, but also a shift towards larger, more energy-intensive connections and a greater number of new station

developments, requiring more complex scheduling, outage coordination, and construction effort.

- System Renewal: As in prior periods, investment is required to sustain transmission system performance and to maintain compliance with applicable reliability standards and regulatory obligations. Hydro One's asset condition assessments indicate a significant and growing proportion of poor condition transmission assets across major asset classes and resulting in higher failure risk and reduced operational flexibility. Hydro One has prioritized planned System Renewal investments to target the most pressing needs, based on asset condition, criticality, performance, and other factors, at a pace that maintains the population of deteriorated assets at a manageable level or avoids a material negative impact on system operations and reliability. System Renewal investments are needed across major asset classes including transformers, breakers, protection systems, conductors, insulators, and wood poles.

To meaningfully reflect customer preferences and needs, Hydro One undertook an enhanced, two-phase customer engagement process that directly informed the planning process and integrated customer input into the development of the plan. Importantly, the plan reflects this customer engagement process, through which customer priorities, preferences and trade-offs were considered and incorporated into the investment decision-making process. The resulting plan aligns with strong customer support for maintaining system reliability, proactively addressing deteriorating assets, and enabling load growth across the province. Details of the customer engagement processes and results can be found in SPF 1.6. Bill impacts on a transmission-only basis resulting from approval of the 2028-2032 plan are discussed further in Exhibit H-09-01.

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

1 **Table 1 - Material Transmission Investments and Customer Benefits**

Investment/Description	Need	Main Customer Benefits/Outcomes
System Access Investment		
Halton TS: Build a second 230/27.6kV station (T-SA-03)	Non-discretionary investments in response to regional growth forecasts that require reinforcement of the transmission system.	Expand or reinforce the transmission system to supply electricity to communities across Ontario and support economic growth in those regions. Modify five existing stations and build 19 new stations and carry out more than 90 km of high voltage line work, including more than 80 km of new line construction expected to be in-service during 2028-2032, to enable an estimated 6,000 MW of capacity and support Ontario's growing electricity needs.
H29/H30: Reconductor 230kV circuits (T-SA-08)		
New Transformer Station in Northern York Region (T-SA-09)		
Build Leamington Area Transformer Stations (T-SA-10)		
Customer Connections – Regulated Entities (T-SA-11)		
Customer Connections – Non-Regulated Entities (T-SA-12)		
System Service Investments		
Southwest GTA Transmission Reinforcement (T-SS-06)	Non-discretionary investments required in response to IESO bulk system planning and regional planning recommendations, government directives for transmission expansion due to load growth forecasts, and the need to integrate new generation resources through IESO-directed procurement.	Build new or reinforce various parts of the transmission system to increase system transfer capacity by an estimated 10,000 MW and enable more than 2,500 MW of new generation. These investments will help supply electricity to communities across Ontario to support economic growth in various regions in Ontario.
West of London Transmission Reinforcement (T-SS-09)		
Greenstone Transmission Line – Station Work (T-SS-10)		
Bulk Planning (T-SS-11)		
Regional Planning (T-SS-12)		

Mitigating Short Circuit Limitations (T-SS-13)		
Bowmanville SS Loop Replacement (T-SS-14)		
Waasigan - Station Work (T-SS-16)		
System Renewal Investments		
Network Stations Asset Replacement (T-SR-01) – 41 individual investments to address assets that are in poor condition, have inadequate performance or are obsolete at transmission network stations at a cost of $695.0M over the five-year period.	Investments in network stations are driven by asset condition, performance and obsolescence. For example, more than one in four transformers (209, or 29%) are currently in poor condition. Investments are prioritized based on safety, compliance, reliability and environmental criteria.	Network stations are a critical part of the transmission system, helping to safely and reliably transport electricity from major generation resources to more than 5 million end-use customers across Ontario. Replacing assets that are in poor condition, have inadequate performance or are obsolete helps ensure continuous and uninterrupted access to reliable electricity across the province.
Connection Stations Asset Replacement (T-SR-03) – 104 investments to address assets that are in poor condition, have inadequate performance or are obsolete at connection stations at a cost of $2,059.0M over the five-year period.	Connection station investments, similar to network stations, target assets that are in poor condition, have inadequate performance or are obsolete.	Connection stations are a critical component of the transmission system, serving local areas and connecting LDCs and large industrial customers to the transmission system. LDCs, in turn, serve Ontario's residential, commercial, institutional and small industrial end-users, including critical infrastructure such as telecommunications systems, water and wastewater treatment facilities, hospitals, airports and transportation systems, schools and universities. Replacing connection station assets that are in poor condition, have inadequate performance or are obsolete, helps Hydro One continue to provide the electrical energy necessary to power the provincial economy and meet society's daily needs.

Transmission Line Refurbishment & Component Replacement (T-SR-04, 05, 06, 07, 08, 13 & 17) – 26 individual investments that target the complete refurbishment of 1,489 km poor condition overhead transmission lines; and component replacement programs addressing poor condition wood poles, steel structures, foundations, insulators and shieldwires; at the cost of $2,502.0M over the five-year period for Hydro One.	Investments are driven by the need to refurbish or replace transmission line components that are in poor condition and have functionally deteriorated. Many circuits are located in public areas, where failures pose significant public safety risks. This renewal work also addresses radial line components located in Northern Ontario that, if they fail, could result in customer outages.	Transmission lines are a foundational component of Ontario's electric power system. They safely and reliably transport large volumes of electricity over long distances from generation facilities to load centres, serving over 5 million end-use customers across the province. These lines are located in publicly accessible areas, and cross highways, major roads and railways. Customers served by radial lines include municipalities, First Nations communities, and large load facilities such as petrochemical processing facilities, mines and paper mills. By investing in and replacing poor condition transmission line components, Hydro One helps mitigate public safety and reliability risks across the province.

Hydro One's capital delivery process includes mature oversight, governance, and project execution processes required to carry out the proposed capital plan. As described in TSP Section 2.11, Hydro One has successfully delivered large capital work plans and reduced the variability of capital expenditures and in-service additions using a skilled internal workforce and qualified third-party contractors.

2.1.2 TRANSMISSION SYSTEM AND SERVICE AREA

The size, scope and criticality of Hydro One's transmission system fundamentally impact the investment requirements and decisions reflected in this TSP. Notably, Hydro One's transmission system:

- extends across the province, operating in diverse geographic and climatic conditions;
- from a system planning perspective, serves a critical role in the daily lives of Ontario's residents and economy by serving large industrial end-users that require reliable energy supply and high-power quality to support their facilities and industrial processes, LDCs, and almost all of the province's generation resources; and
- forms part of the North American bulk electric system (BES), making it subject to mandatory compliance with North American Electric Reliability Corporation (NERC) standards, which determine the required reliability (i.e., adequacy and security) of the BES under most system conditions.

2.1.2.1 SCOPE OF THE TRANSMISSION SYSTEM

Hydro One's transmission system transmits electricity throughout the Province of Ontario. In 2025, Hydro One transmitted 146 TWh of electricity, directly or indirectly, from supply points (i.e., generation) to substantially all consumers of electricity in Ontario.

The maps in Figures 1 and 2 below depict Hydro One's transmission service area in northern and southern Ontario, respectively. Each area presents unique challenges. For example, the climate across Ontario also varies significantly by location and season with Hydro One's transmission system being susceptible to a variety of extreme weather

conditions, such as blizzards, ice storms, lightning, extreme heat and tornadoes, in different areas at any one time.

Figure 1: Hydro One Transmission System in Northern Ontario

Figure 2: Hydro One Transmission System in Southern Ontario

In addition, Hydro One's transmission system enables the operation of all other licensed transmission systems in Ontario, including Canadian Niagara Power Inc., Five Nations Energy Inc., Wataynikaneyap Power LP (Watay), Hydro One Sault Ste. Marie LP (HOSSM), Niagara Reinforcement Project Limited Partnership (NRLP), Upper Canada Transmission 2 LP (UCT 2 doing business as East-West Tie LP), B2M Limited Partnership (B2M LP), Chatham x Lakeshore Limited Partnership (CLLP) and Waasigan Transmission Line Limited Partnership (WTLP). It also interconnects with five neighbouring transmission systems in Canada and the United States (Manitoba, Quebec, Minnesota, Michigan and New York), enabling interjurisdictional electricity transfers through 26 interconnections, as shown in Figure 3, below.

Ontario's transmission interties to Manitoba, Quebec, Minnesota, Michigan and New York represent a total nominal capacity[5] of about 6,000 MW.

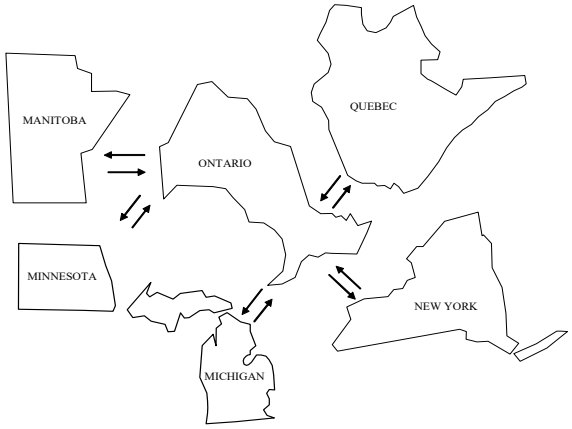

Figure 3: Existing Ontario Transmission Interconnections

2.1.2.2 KEY TRANSMISSION ASSETS

Hydro One's transmission system consists of transmission lines, transmission stations and system operations facilities operated at primarily 500 kV, 230 kV or 115 kV, with some parts at 345 kV. It is designed to safely and reliably transport large volumes of electricity over long distances from generation facilities to load centres. Transmission lines are comprised of overhead conductors, underground cables, steel and wood pole structures, foundations, insulators, shieldwire, switches and line hardware. Bulk transmission lines, discussed further below, deliver power from generating stations or connections to receiving stations. Area supply lines take power from the network and transmit it to customer supply transmission stations near customer load centres.

Transmission stations are critical infrastructure. They are used to deliver power, provide voltage transformation and switching, and serve as load and generator connection points, as well as interconnection points with other Ontario transmission systems and those located in neighbouring provinces and states. Transmission stations are comprised of power transformers, circuit breakers, protection and telecom systems, disconnect

[5] Ontario Ministry of Energy & Mines, Integrated Energy Plan: Energy for Generations – Ontario's Integrated Plan to Power the Strongest Economy in the G7, June 2025, pp.140

switches, bus work, insulators, power cables, surge arrestors, capacitor banks, reactors, station service, grounding systems, site infrastructure and buildings.

Hydro One's transmission system is controlled from a centralized control centre or back-up centre, when required, to support reliable operation of the system. Furthermore, Hydro One's transmission business includes a fleet of general plant assets including facilities, transport and work equipment, as well as information and operating technology that are critical to operation of the transmission system (see the General Plant System Plan in Exhibit B-04-01).

A snapshot of Hydro One's key transmission system-related assets is presented in the tables below.

Table 2 - Hydro One – Key Transmission System Assets

System Assets	Total
Operating Centres	2
Length of Overhead Transmission Lines (Total Circuit km)	28,488
Length of Underground Transmission Cables (Total Circuit km)	279
Transmission Stations (Total Number)	297
Installed Transformer Nameplate Capacity (MVA)	118,575

2.1.2.3 TRANSMISSION CONNECTED CUSTOMERS

A profile of the customer base connected to Hydro One's transmission system is presented in Table 3, below.

Table 3 - Hydro One's Transmission Connected Customers[6]

Customer Type	Number Served
Generators	139
End Users (Large Industrial Customers)	88
Local Distribution Companies	34

Transmission connected generation customers represent almost all of Ontario's total generation capacity, including most of Ontario's hydroelectric generation facilities, all natural gas fueled generation facilities, large renewable generation facilities and all of Ontario's nuclear generation facilities. A transmission outage to any one of these facilities directly affects Ontario's generation supply thereby affecting Ontario's reliability of supply and the electricity price. Transmission outages can affect generation facility equipment and cause prolonged station shutdowns, which could affect electricity market pricing ultimately borne by ratepayers.

Directly connected large industrial customers are a critical part of Ontario's economy and include facilities for steel production, auto manufacturing, pulp and paper, chemical processing and mining. Transmission outages and power quality issues can cause significant and costly interruptions to industrial processes and customer equipment, which in turn can affect company safety, performance, and employment. Reliable electrical service is a significant factor for large industrial customers deciding to locate and remain located in Ontario.

Directly connected LDCs serve most of Ontario's residential, commercial, institutional and small industrial end-users. The end-user facilities that are indirectly affected by the

[6] The number of customers in this table is based on the number of Transmission Connection Agreements (TCAs) as required by the Transmission System Code (TSC) with the exception of LDCs that are based on their Electricity Distribution Licence as of December 31, 2020.

reliability and performance of Hydro One's transmission system include critical infrastructure such as embedded LDC's, telecommunications systems, water and wastewater treatment facilities, hospitals and other health care facilities, airports, transportation systems, schools and universities, and financial services.

2.1.2.4 CRITICALITY OF THE TRANSMISSION SYSTEM

The scope of those served by and the scale of Hydro One's transmission system make it critical infrastructure for Ontario, consistent with the definition of "critical infrastructure" adopted by the Province for purposes of the Ontario Critical Infrastructure Assurance Program.[7] Because of this critical role, Hydro One's transmission system is the "backbone" of Ontario's electricity system that plays a central role in the interconnected system of critical infrastructure that ensures food security, water safety, telecommunications, and economic stability for Ontarians.[8]

The Hydro One transmission system delivers electricity to almost every Ontario community, making reliability a critical objective of the system's design and operation. Redundancy has been built into the design of Hydro One's transmission system, particularly in southern Ontario to ensure a level of reliability proportionate to the system's critical role within the province. This is consistent with transmission customers' expressed strong preference for reduced momentary outages and investment in a more reliable system.[9]

In addition, Hydro One maintains, manages and invests in its transmission system to comply with the reliability standards applicable to the BES. The BES includes all transmission facilities greater than 100 kV, which encompasses the vast majority of Ontario's (and Hydro One's) transmission system.[10] This reliability framework is based on the NERC reliability standards adopted and enforced in Ontario by the IESO. NERC

[7] See https://www.ontario.ca/page/ontario-critical-infrastructure-assurance-program-strategy
[8] Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7, p.83
[9] SPF Section 1.6 Attachment 1 – Customer Engagement Report, p 16
[10] Hydro One applies the NERC definition of the BES that was approved by the Federal Energy Regulatory Commission (FERC) effective July 1, 2014.

standards ensure the integrity not only of Ontario's BES but also all interconnected BESs across North America. Hydro One is also a member of the Northeast Power Coordinating Council (NPCC) registered under NERC's compliance registry. As one of the eight regional entities that NERC works with to improve BES reliability, NPCC also develops regional reliability standards, monitors and enforces compliance, and coordinates regional system planning, design and operations, and assessments of reliability.

As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards adopted by NERC and NPCC. These standards and criteria require adequate and secure supply over a wide range of conditions so that loss of one or more elements (line or stations asset) will not result in any violation of thermal or stability limits. This means that a failure of one of two transformers or circuits supplying a delivery point does not impact service to customers (i.e., supply continues uninterrupted from the remaining transformer or circuit).[11] Nonetheless, such failures are a major concern for Hydro One. The failure of a circuit or transformer can take considerable time to replace. A second asset outage in conjunction with the prior asset failure could result in a lengthy delivery point interruption for the IESO and the LDCs supplied from that delivery point. Further, when one transformer is out of service, the in-service transformer can see loading up to 130-160% of its transformer rating, thus greatly exacerbating the risk that the transformer could fail (especially if it is in poor condition) and a lengthy delivery point interruption may result. Accordingly, Hydro One cannot wait for delivery point performance to deteriorate before undertaking required investments on dual supplied delivery points where a failure has occurred. Delivery point performance is a lagging indicator of asset condition and the impact of renewal investments (or the absence thereof) and cannot be used to drive future investment decisions. By the time reliability degradation manifests for dual-supplied delivery points, equipment performance would have already unacceptably worsened, with associated impact on customer delivery continuity, system operability, and public safety.

[11] 70% of the delivery points on Hydro One's transmission system are multi-circuit delivery points, meaning that more than one line is normally available to supply the customers connected to such a delivery point. The remainder of the transmission system features single-circuit delivery points.

There are 126 Hydro One transmission stations that include assets designated as part of the BES.[12] With respect to protections and controls, to comply with NERC and NPCC reliability standards, these BES stations are equipped with multiple, redundant and robust protection and control systems. These systems ensure that faults are isolated to prevent cascading failures and damage to assets near the fault. Infrastructure for key sites and processes is designed to adhere to NERC Critical Infrastructure Protection (CIP) requirements. NERC and/or NPCC requirements require additional equipment, such as redundant protection systems and station battery systems, and sites must meet additional CIP requirements, such as physical and electronic/cyber-security to prevent unauthorized network access. Hydro One's maintenance and investment plans are prioritized to maintain compliance with these requirements. When replacing assets to address condition-related risk or system requirements, Hydro One may have no choice but to make upgrades since like-for-like replacement may not match current NERC standards.

2.1.3 PROPOSED TSP INVESTMENTS

Hydro One's proposed 2028–2032 TSP is designed both to maintain the integrity of the system and position the transmission network to support Ontario's rapidly evolving energy future. Over the 2028-2032 period, Hydro One plans to invest an average of $3,330.5M per year in Transmission capital to sustain strong reliability performance, address increasing customer and system needs, support government policy objectives related to system expansion, comply with evolving regulatory requirements, and proactively manage asset and operational risks through timely and disciplined investment, consistent with customer needs and preferences.

The 2028-2032 plan was informed by customer engagement, as discussed in SPF Section 1.6 and SPF Section 1.7. To identify customer needs and preferences, Hydro One engaged an independent third party, Innovative Research Group, to design and conduct a comprehensive, two-phased customer engagement study. This process enabled Hydro One to meaningfully incorporate customer perspectives and explicitly consider trade-offs between investment levels and customer outcomes.

[12] Designation of BES facilities is based on the bus structures. Some Hydro One stations contain more than one bus network.

Between 80% and 88% of Hydro One's Transmission-only customers supported investment levels at or above the draft plan and bill impacts presented to them. This strong level of support reflects customer recognition of the importance of maintaining a reliable and resilient transmission system while preparing for future growth.

In response to increasing customer and system needs, asset condition needs, and government policy objectives discussed above, Hydro One proposes a $16,652.4M Transmission Capital Portfolio over the 2028-2032 period and $309M in prepaid related to Cloud expenditures (see General Plant System Plan, Exhibit B-04-01). Table 4 and Figure 4 summarize the planned expenditures by OEB investment category and forecast years.

Table 4 - Forecast Period Expenditure Summary ($M)

OEB Investment Category	Forecast Period [13]					% of Portfolio
	2028	2029	2030	2031	2032	
System Access	286.4	363.5	560.7	320.1	98.1	9.8%
System Renewal	955.2	1,072.4	1,435.0	1,864.4	1,766.6	42.6%
System Service	1,102.4	1,391.9	1,432.4	1,577.5	1,138.9	39.9%
General Plant (Transmission)[14]	287.9	259.0	275.3	247.2	217.6	7.7%
Total Capital	**2,631.9**	**3,086.7**	**3,703.3**	**4,009.3**	**3,221.2**	**100%**
Prepaid Related to Cloud (Transmission)[14]	70.9	65.4	70.4	58.4	44.0	

[13] Where all or part of a project is expected to be owned by and included in the rate base of a newly licenced partnership (i.e., will not form part of Hydro One's rate base), Hydro One has excluded the proposed capital expenditures from the 2028-2032 forecast.
[14] Details on General Plant expenditures and Prepaid related to cloud, are found in Exhibit B-04-01 General Plant System Plan (GSP).

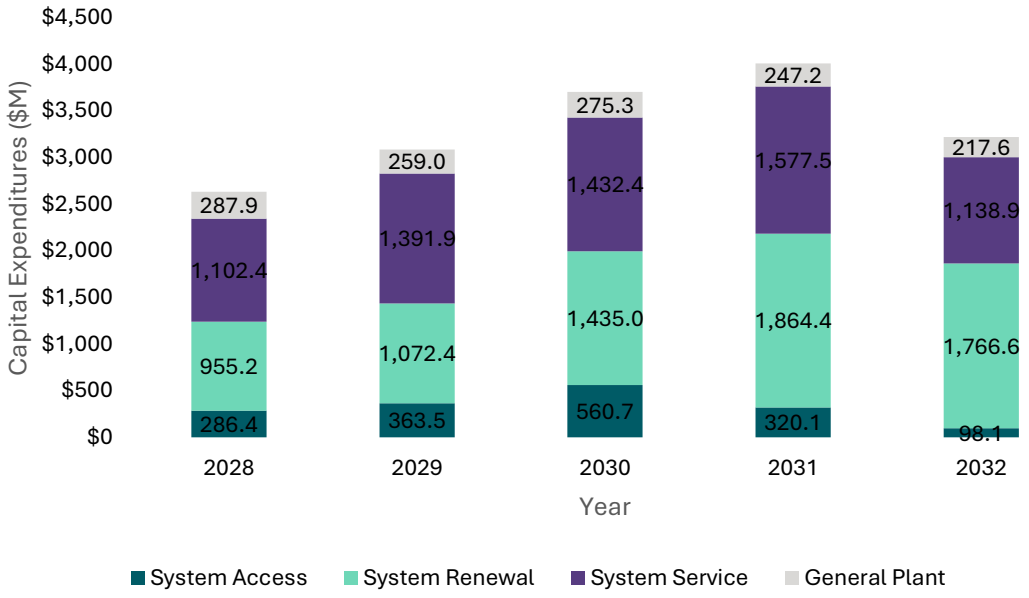

Figure 4: Forecast Period Capital Investment Summary ($M)

As illustrated in Figure 5, the proposed Transmission Capital Portfolio reflects a significant evolution in Hydro One's investment plan in response to evolving system and customer needs.

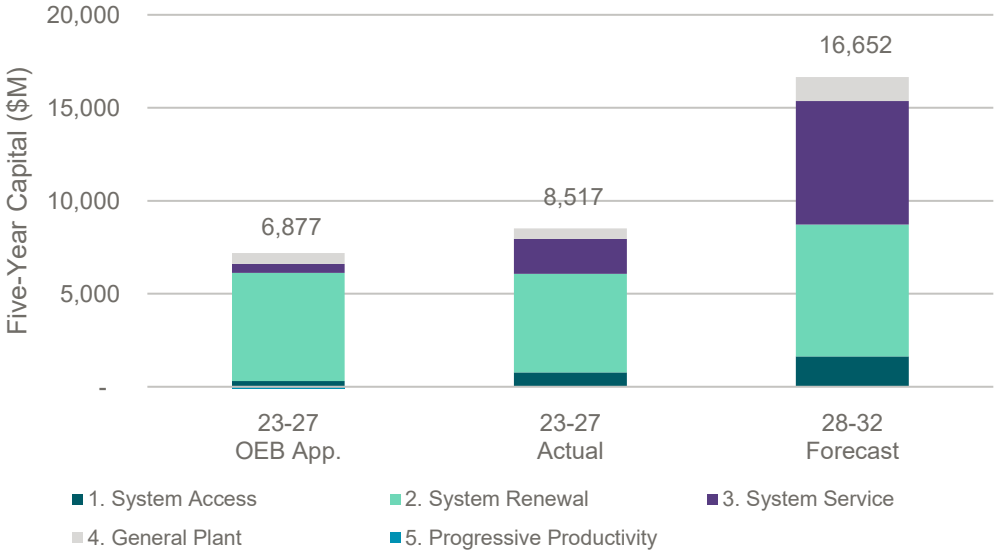

Figure 5: Transmission Capital Portfolio, 2023-2027 period vs. 2028-2032 period

While System Renewal remains the single largest investment category within the proposed portfolio, growth in nondiscretionary System Access and System Service investments explains much of the increase in overall capital portfolio relative to the prior rate period. Continued investment in System Renewal remains essential to maintaining a safe, and reliable transmission system. The proposed portfolio reflects a combination of ongoing condition-based renewal requirements, the continued execution of reprioritized renewal work, and the ongoing need to address additional asset condition requirements over time. The categories of investments, discussed in the sections that follow, are fundamental to maintaining system performance and ensuring that the transmission network remains capable of supporting Ontario's growth and electrification.

2.1.3.1 SYSTEM ACCESS: CUSTOMER CONNECTIONS AND ECONOMIC GROWTH

A primary driver of the transmission investment plan is the unprecedented increase in customer connection requests across the province. System Access investments are mandatory investments that facilitate new load and generation customer connections and address transmission asset modifications to accommodate third party requests. These investments are required to provide timely, efficient access to the transmission system and to enable broader economic development opportunities across the province. They reflect Hydro One’s central role in facilitating growth by ensuring that businesses, communities, and new industries can connect to a reliable electricity network. These investments account for about $3,561.8M of the gross capital expenditures for the five-year period. The costs of these investments are partly or wholly recoverable from customers in accordance with the Transmission System Code, resulting in net capital expenditures of $1,628.8M or 9.8% of the total net capital expenditures over the five-year plan. However, even on a net basis this amount reflects a significant increase of more than five times over the 2023-2027 period.

Since 2023, the number of transmission connection requests has doubled to approximately 200 per year, reflecting growing demand for access to Ontario's electricity system. In 2024, Hydro One managed approximately 97 customer connection projects. By the end of the second quarter of 2026, the active portfolio had increased to

approximately 166 projects, representing growth of more than 70%. Similar trends are evident in generation connections. Hydro One managed approximately 19 new generation connection projects in 2024 and anticipates approximately 50 new generation connection applications over the 2026-2027 period, driven primarily by IESO resource procurement initiatives. This growth reflects increasing demand for both load and generation connections and contributes to the expanding scale of System Access investment requirements. The increase in connection activity is concentrated across key regions of Ontario, including Southwest Ontario, the Greater Toronto Area, the Greater Ottawa Area, and the Hamilton to Nanticoke corridor. Both the volume and the scope of individual connection projects have increased materially. The 2023-2027 period included 25 planned connection projects as compared to 56 proposed connection projects for the 2028-2032 period. The portfolio also includes larger and more complex projects. For example, the previous rate period included five new dual-element spot network (DESN) stations, whereas the 2028-2032 plan includes 19 new DESN stations. Construction of a new station is generally more complex and resource intensive than high voltage line work, requiring greater outage scheduling, outage coordination and construction effort. The increase is not solely attributable to a greater volume of projects; it also reflects a shift toward larger, more energy intensive customers. Data centres, for example, account for only 6 of the 56 projects (10.7%), but are estimated to require approximately 1,425 MW of capacity, representing approximately 22.7% of the more than 6,000 MW of capacity expected to be enabled by the System Access portfolio during the rate period. This is equivalent to more than 5% of Ontario's peak demand. This trend is forecast to continue throughout the 2028-2032 period. These investments result in highly reliable, redundant infrastructure and play a key enabling role in supporting Ontario's economic growth and the electrification of emerging sectors.

System Access investments are detailed in TSP Section 2.8 and the System Access (T-SA) ISDs are included in TSP Section 2.12. The increase in the 2028-2032 System Access capital expenditures is driven by a number of investments including the following investments:

- Customer Connections – Regulated Entities: Hydro One plans to invest approximately $2,017M in gross capital expenditures over the 2028-2032 period for new customer connections for regulated entities. As a portion of this work is recoverable from customers, the associated net capital impact of this work is approximately $1,094.9M. Key drivers include investments in the Windsor-Essex Region to construct two load connection stations in the Kingsville-Leamington area and two load connection stations in the Coatsworth area, together with associated 230 kV line expansions to support growing agricultural demand and system restoration needs. These investments are forecast to cost approximately $326.3M for the Kingsville-Leamington area and $202.7M for the Coatsworth area in gross capital expenditures, for a combined total of approximately $529.0M. After customer capital contributions, the corresponding net capital impacts are approximately $291.3M for the Kingsville-Leamington area investments and $168.6M for the Coatsworth area investments, for a combined total of approximately $459.8M. Growth in the Burlington to Nanticoke region also drives approximately $315.1M of gross capital expenditures over the 2028-2032 period. These investments include the construction of four new stations to meet growing customer demand in the region. After customer contributions, the associated net capital impact is approximately $246.6M. Further details are provided in TSP Section 2.12, T-SA-03, T-SA-08, T-SA-09, T-SA-10 and T-SA-11.

- Customer Connections – Non-Regulated Entities: Hydro One plans to invest approximately $230.5M in gross capital expenditures over the 2028-2032 period for new customer connections for non-regulated customers, including data centres and other large industrial facilities. As a portion of this work is recoverable from customers, the associated net capital impact is approximately $163.9M. These investments are further described in TSP Section 2.12, T-SA-12.

- Secondary Land Use and Transmission Asset Modifications: Investments to support secondary land use and transmission asset modifications account for approximately $390.2M of gross capital expenditures over the 2028-2032 period. After customer capital contributions, the associated net capital impact is

approximately $239.6M. These investments include the relocation, removal, or reinforcement of transmission assets to facilitate third-party projects (e.g., roadwork, transit systems, and other major infrastructure or development work) that may encroach upon or impact Hydro One assets and rights-of-way. A significant driver of planned expenditures is the West Toronto Transmission Line Relocation project proposed by Metrolinx, which involves relocating transmission circuits K1W/K3W between Eglinton Avenue West and St. Clair Avenue West using underground cables to accommodate transit system expansion and related development in the corridor. Further details are provided in TSP Section 2.12, T-SA-07.

2.1.3.2 SYSTEM RENEWAL: MAINTAINING THE GRID AND STRENGTHENING THE SYSTEM

System Renewal investments are required to sustain the reliability and operational capability of Hydro One's transmission system as customer and system needs continue to grow. These investments address asset condition, performance, and obsolescence risks through the replacement or refurbishment of deteriorated assets, ensuring the existing transmission network continues to provide safe and reliable service while supporting Ontario's evolving electricity needs. System Renewal investments account for 42.6% of Hydro One's 2028-2032 net capital expenditures. These investments will manage and mitigate risks primarily stemming from poor condition (as indicated by condition assessments) and failed assets, but also from inadequate performance and functionally obsolete assets.

For major Hydro One transmission assets, the poor population percentage at the end of 2016, 2018, 2020 and 2025 (current and previous rate filing condition data) is shown in Figure 6. Asset condition trends indicate increasing risk across the transmission system, with the most significant deterioration observed in transformers and wood structures. Poor-condition transformers increased from 16% in 2016 to 29% in 2025, reflecting a materially aging fleet and a growing reliability risk. Transformer failures reduce station redundancy, increase loading on remaining units, and elevate the likelihood of cascading outages. While the condition of breakers remains relatively stable (9–11% poor condition),

approximately 44% of the fleet is obsolete, increasing long-term operational risk due to declining vendor support and spare parts availability. Protection systems remain consistently high-risk, with about 26% of assets beyond expected service life, increasing the likelihood of mis-operations and compliance risk. Conductor condition has also degraded, increasing from 9% poor condition in 2016 to 14% in 2020, with only a partial recovery to 11% in 2025. Conductor health remains below historical levels, heightening susceptibility to mechanical failures and weather-driven outages. Wood structures show the most pronounced decline, with poor-condition assets rising from 12% to 19% over the same period, signaling an aging pole population and a widening renewal gap. This significantly increases the risk of structural failures, safety hazards, and weather-related outages.

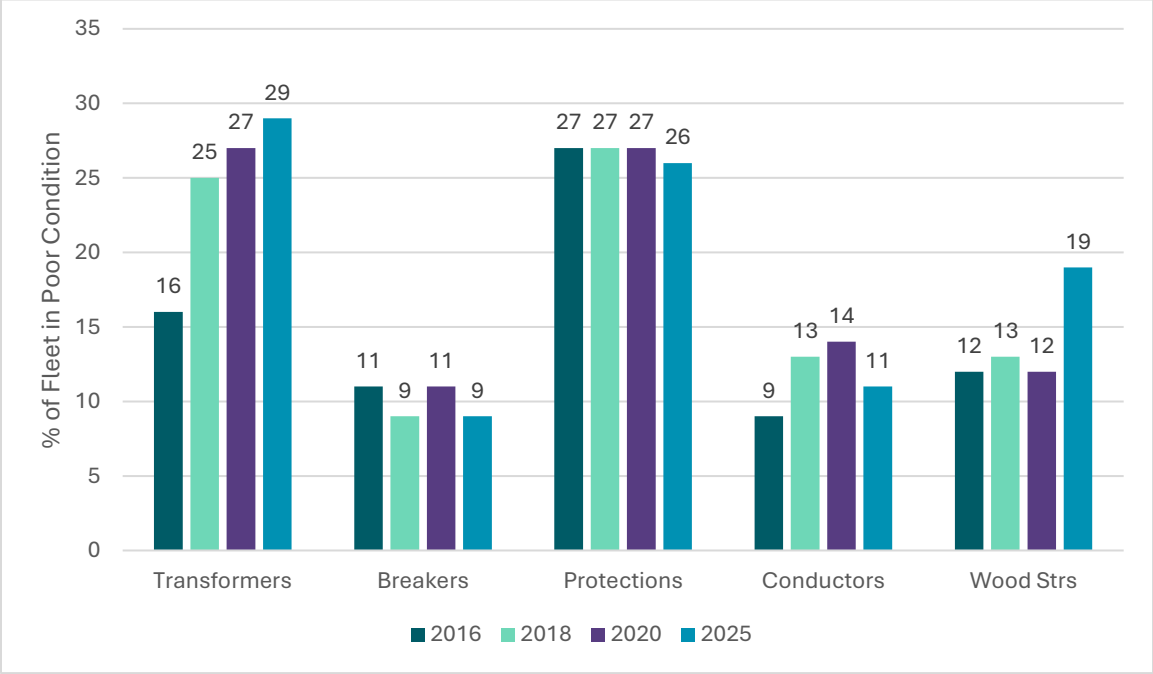

Figure 6: Percentage of Major Hydro One Transmission Assets in Poor Condition

System Renewal investments have been selected based on asset condition, their criticality, performance and obsolescence criteria, considering customer needs and preferences, and Hydro One's ability to execute the renewal work. System Renewal investments have been reasonably paced to predominantly address assets that are in poor condition, have

inadequate performance, or are obsolete; and include an average annual replacement rate of:

- 2.4% of the transformer fleet,
- 1.5% of the breaker fleet,
- 2.6% of the protection fleet,
- 1.0% of the conductor fleet,
- 2.8% of the insulator fleet, and
- 2.9% of the wood pole fleet.

Despite the comprehensive assessment criteria used to determine the System Renewal needs, changing system conditions, unexpected failures, localized outage constraints or generation resource constraints can materially shift investment priorities. The coordination of multiple changing factors and priorities with customer and system needs has continually increased the complexity of project execution plans, and this is expected to be a factor closely monitored to allow for adjustments during the 2028-2032 period.

The proposed System Renewal investments reflect a forward-looking approach to asset stewardship, maintaining current reliability while strengthening the system for future demands. These investments are informed by robust condition assessments, risk analysis, and customer engagement feedback.

Accordingly, System Renewal remains the largest investment category, reflecting Hydro One's commitment to prudent lifecycle asset management, regulatory compliance, and the long-term resilience of Ontario's electricity system. These investments are essential to avoiding future reliability risks and ensuring the system remains capable of supporting Ontario's continued growth and electrification.

System Renewal investments are detailed in Section 2.8 and the System Renewal (T-SR) ISDs are included in Section 2.12. Major renewal investments over the 2028-2032 planning period include:

- Transmission Station Renewal – Connection Stations: Hydro One plans to invest $2,059.2M over the 2028-2032 planning period in the renewal of connection

stations (TSP Section 2.12, T-SR-03). Connection stations directly supply industrial and commercial customers and LDCs. Investments at these stations are critical to the reliability of directly connected LDCs and industrial and commercial customers.

- Transmission Station Component Replacement: Hydro One plans to invest $410.3M over the 2028-2032 planning period to replace individual transmission station assets that are in poor condition (TSP Section 2.12, T-SR-22). This investment is a targeted component of the hybrid station investment approach and it is complementary to the integrated investments discussed in TSP Section 2.12 T-SR-01 and T-SR-03.

- Transmission Station Demand and Spares: Hydro One plans to invest $347.9M over the 2028-2032 planning period in the emergency replacement of failed transmission station assets, and the procurement of strategic spare inventory. This investment supports the reliability of the bulk system and directly connected LDCs, industrial and commercial customers (TSP Section 2.12, T-SR-09).

- Transmission Line Renewal: Hydro One plans to invest $1,035.4M over the five-year period to replace or refurbish 1,369 circuit-km of transmission lines and place them in service, addressing 45% of the known poor condition conductors in the fleet. These conductor sections will be addressed through 13 investments. This renewal work sustains service to a variety of network and radial line connected customers, including large and small municipalities, First Nations communities, and large load facilities such as petrochemical processing facilities, mines, and paper mills. Currently, 3,079 circuit-km (11%) of Hydro One's conductor fleet is in poor condition, with another 5,296 circuit-km (19%) exhibiting some deterioration (see TSP Section 2.12, T-SR-13).

- Transmission Line Component Replacement: Hydro One plans to invest $1,467M over the five-year period to replace or refurbish various transmission line components such as wood poles, steel structures, foundations, insulators and

shieldwires that have been confirmed to be in poor condition. These components are integral parts of the transmission line system required to support the overhead conductors and enable them to perform their functions (see TSP Section 2.12, T-SR-04, T-SR-05, T-SR-06, T-SR-07, T-SR-08, T-SR-17).

2.1.3.3 SYSTEM SERVICE: ENABLING REGIONAL AND BULK SYSTEM EXPANSIONS

The transmission investment plan is also shaped by a significant increase in System Service investments arising from regional and bulk system planning processes. System Service investments are required to maintain inter-area network transfer capability, ensure local area supply adequacy, mitigate system risks related to safety, security and reliability, and address customer power quality concerns.

During the 2023-2027 rate period, Hydro One experienced unprecedented growth in customer connection demand and system expansion needs. This growth is expected to continue and intensify throughout the 2028-2032 rate period. As a result, Hydro One's planned 2028-2032 System Service expenditures are significantly higher than System Service actual and forecast expenditures in the 2023-2027 period, driven by a material increase in Transmission Regional and Bulk Plan investments. This increase reflects the scale and urgency of system reinforcements required to accommodate changing load patterns, new generation development, and evolving power flows across Ontario's grid. The growth in system capacity is consistent with the Government of Ontario's Integrated Energy Plan – *Energy for Generations* – which highlights the need for utilities to enable growth, support electrification, and maintain a reliable and resilient electricity system. Hydro One's proposed capital plan is designed to meet these objectives while continuing to fulfill its obligations to maintain transmission reliability performance, address customer needs and priorities, and mitigate asset and operational risks.

System Service investments account for approximately $6,816.0M of gross capital expenditures over the 2028-2032 period. However, some of these investments are recoverable from customers in accordance with the Transmission System Code, resulting

in net capital expenditures of $6,643.1M representing 39.9% of total net capital expenditures over the 2028-2032 period.

The 2028-2032 System Service expenditures include 47 material investments that will result in the construction of 8 new transmission stations, and the expansion or modification of 41 existing stations. The planned investments include more than 350 km of high-voltage line work, comprised of approximately 27 km of new transmission line construction and upgrades to approximately 327 km of existing transmission lines, excluding line work to be undertaken through Affiliated Transmission Partnerships. Of these material investments, 42 arise from Regional Planning frameworks as discussed in SPF Section 1.2 and Bulk Planning considerations described in TSP Section 2.6. This represents a significant increase relative to Hydro One's 2023-2027 rate application, which included only nine material System Service investments, six of which originated from Regional and Bulk Planning processes.

System Service investments are detailed in TSP Section 2.8 and the System Service (T-SS) ISDs are included in TSP Section 2.12. The proposed 2028-2032 forecast is driven by the following key investments resulting from the IESO's Bulk and Regional Planning recommendations, further details on investments are provided in TSP Section 2.12, T-SS-06, T-SS-09, T-SS-10, T-SS-11 and T-SS-12:

- South and Central Region Transmission Reinforcements: Hydro One plans to invest $2,718.0M in transmission reinforcements in the South and Central Regions. These investments include the expansion of Bowmanville SS to connect Ontario Power Generation's (OPG) Small Modular Reactors (SMR) at Darlington ($900M), as recommended in the IESO report "*Connection approach for Small Modular Nuclear Reactors at the Existing Darlington Nuclear Generation Station".* A new 500/230 kV transmission station in the Kleinburg area, together with approximately 6 km of 230 kV double-circuit transmission line from Kleinburg to Kirby area ($428.2M); the Milton TS Expansion ($370.0M); and the Guelph North TS Development ($295.0M), among other investments recommended in the South

and Central Bulk Plan and regional planning studies in Southern Ontario (KWCG, Toronto, GTA West, and Windsor Essex)

- Northern Ontario Transmission Reinforcements: Hydro One plans to invest $1,272.7M over the 2028-2032 rate period in significant 500 kV and 230 kV transmission work recommended by the IESO through Northern Ontario Bulk and Regional Plans. These investments include new 500 kV and 230 kV transmission lines, including a new 500 kV circuit from Hanmer TS to Essa TS, a new 230 kV circuit from Mississagi TS to Hanmer TS, and a new 230 kV circuit from Mississagi TS to Third Line TS, also known as the North Shore Link. Further details on these investments are provided in TSP Section 2.12, T-SS-11.

- Eastern Ontario Reinforcements: Hydro One plans to invest $260.0M over the 2028-2032 rate period in Eastern Ontario reinforcements. The work recommended by the IESO through Eastern Bulk Planning includes station work associated with new 230kV line from Napanee to Belleville, including a new switching station in the Belleville area and additional considerations for reactive support, station work associated with a new 230kV line from St. Lawrence to Merivale, and station upgrade work in Hawthorn TS. The investments also include station work associated with Durham Kawartha Power Line. Further details are provided in TSP Section 2.12, T-SS-11.

- Greater Ottawa Transmission Reinforcements: Hydro One plans to invest $304.4M over the 2028-2032 rate period in Kanata Area Transmission Reinforcements and other regional investments recommended by the IESO through Ottawa Regional Planning. These investments include a new 230 kV line between Merivale TS and South March TS. Further details are provided in TSP Section 2.12, T-SS-12; and

- Greenstone Transmission Line Connection: Hydro One plans to invest $95.0M over the 2028-2032 rate period in the station work required to connect the 230 kV Greenstone Transmission Line, which is a priority project of the Provincial

Government in Northern Ontario. Further details are provided in TSP Section 2.12, T-SS-10.

2.1.3.4 GENERAL PLANT

General plant investments are related to assets that are not part of the electrical transmission system, such as facilities and real estate, transport and work equipment, information technology, and security. A specific section has been dedicated to General Plant expenditures in the General Plant System Plan (Exhibit B-04-01).

2.1.4 THE TSP IS REASONABLE AND APPROPRIATE

The TSP is based on robust asset management practices and investment planning processes that incorporate known asset condition data, customer engagement and system and regional planning inputs that reflect connection and service requirements that facilitate economic and electrical growth. The planning basis for the TSP is highlighted below (including the outcome-based planning context, asset management process, and investment planning process as illustrated in Figure 7 below) followed by a discussion regarding Hydro One's ability to execute the proposed plan. The planning process is detailed in SPF Section 1.7 and TSP Section 2.7, and work execution is detailed in TSP Section 2.11.

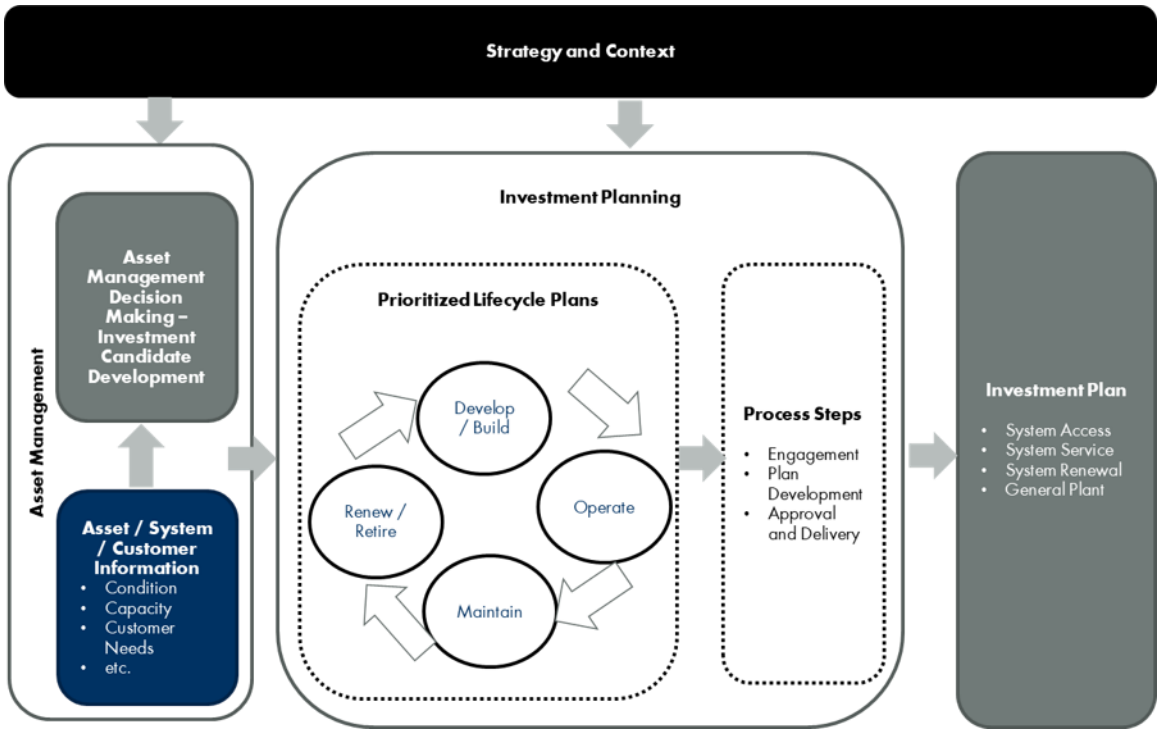

Figure 7: System Planning Process Diagram

2.1.4.1 PLANNING CONTEXT

Hydro One has robust asset management practices and an investment planning process designed to drive customer-centered outcomes in alignment with the OEB's RRF outcomes:

- **Customer Focus:** maintaining and improving power quality, equipment availability, and customer reliability in response to identified customer preferences.
- **Operational Effectiveness:** Achieving top-tier safety performance and eliminating serious injuries, maintaining, and improving (where required) long-term reliability by mitigating risk arising from asset deterioration as well as minimizing long-term costs to maintain the transmission system.
- **Public Policy Responsiveness:** ensuring compliance with mandated statutory and regulatory obligations; and
- **Financial Performance:** achieving manageable and stable rate impacts over the course of the planning period.

Hydro One is committed to meeting the RRF outcomes and has integrated them into its investment planning. Table 5 below demonstrates the close alignment of Hydro One's business objectives to the RRF outcomes. As shown through various transmission investment summary documents (see TSP Section 2.12), each investment reflects explicit consideration for the achievement of RRF aligned outcomes.

Table 5 - Alignment of Plan Outcomes with RRF Performance Outcomes

RRF Outcomes	Hydro One Objectives	Plan Outcomes
Customer Focus	Customer Experience	• Improve current levels of customer satisfaction • Deliver exceptional experiences and empower customers • Acknowledge Indigenous Partners as core to growth
Operational Effectiveness	Safety	• Achieve top-tier safety performance and eliminate serious injuries
	Cost Control	• Focus on continuous improvement to enhance efficiency, productivity, and reliability
	Employee Engagement	• Achieve and maintain employee engagement
	Work Programs and System Reliability	• Deliver on operational commitments to renew, expand, and enhance the grid • Maintain Transmission reliability and improve Distribution reliability
Public Policy Responsiveness	Public Policy Responsiveness	• Deliver on obligations mandated by government through legislation and regulatory requirements • Actively enable the energy transition and shape the net zero future
	Environment	• Lower Hydro One's environmental footprint through greenhouse gas reduction
Financial Performance	Financial Performance	• Responsible investment in rate base assets to ensure the safety and reliability of the grid • Establish new partnerships that generate value and create high value results • Enable an affordable energy transition through investments that reflect customer feedback

2.1.4.2 CUSTOMER ENGAGEMENT

As detailed in SPF Sections 1.6 and 1.7, feedback from customer engagement directly informed and shaped the development of the investment plan. In 2024 and 2025, Hydro One retained Innovative Research Group (IRG) to conduct Hydro One's multi-phase customer engagement process to inform and refine the investment plans in this application (the IRG Study).

Phase I took place in mid-to-late 2024, prior to the beginning of the investment planning process for the years 2028-2032 and focused on identifying customer needs and preferences to inform the initial stages of investment planning. Phase II was carried out in the late fall of 2025 and provided customers with an opportunity to provide specific feedback on Hydro One's draft investment plans, including on significant investment trade-offs in the plans. The Phase II results were incorporated into the final investment plans submitted in this Application.

The Transmission System Plan is closely aligned with customer needs and preferences. The IRG Study results indicate strong support for Hydro One's proposed investment plans. As stated in the IRG Overview Report (see SPF Section 1.6, Attachment 1): "Overall, feedback collected from more than 100,000 customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's 2028-2032 draft plans."

The following customers who are directly connected to Hydro One's transmission system, as well as Ontario customers that are served by other LDCs, had the opportunity to participate in the IRG Study and the transmission system planning process:

- Transmission-connected end-users
- Transmission-connected generators
- Transmission-connected LDCs
- Residential customers outside of Hydro One's distribution territory
- Small Business ratepayers outside of Hydro One's distribution territory

Customer feedback in Phase I provided valuable input on customer priorities, including indicative investment envelopes and preferred outcomes. Hydro One used this input to develop initial scenarios for the investment plans. As described in the IRG Overview Report, key customer feedback from Phase I in respect of transmission included the following:

- A majority of customers support Hydro One making investments to either maintain or increase current levels of reliability related to the transmission grid.

Taking into account the Phase I customer feedback and results, Hydro One's planners developed alternative investment plan scenarios: a draft plan; a plan that adopts a somewhat "spend more" option of investment relative to the draft plan; and a plan that adopts a somewhat "spend less" option of investment relative to the draft plan. These alternative investment scenarios formed the basis of options presented to customers in Phase II.

Through Phase II of Customer Engagement, over 100,000 customers completed the online workbook. As described in the IRG Overview Report, key customer feedback from Phase II, in respect of transmission, included the following:

- Across all customer types, a majority or near majority of customers selected Hydro One's draft plan level of spending as it relates to transmission investments in keeping pace with transmission renewal, and stewardship of the transmission system.
- Customers expressed strong support for the replacement of aging and deteriorating transmission system assets to manage the risk of equipment failure and support growth across the province. These include the replacement of transmission station transformers and breakers, and high-impact underground transmission cables.
- Customers also expressed strong support for investments to enhance Hydro One's stewardship of the transmission system. A majority of customers support

the draft plan, including replacing at-risk transmission lines, reinforcing wood poles, and extending the life of steel towers and accelerating the clearing of overgrown trees.

As detailed in SPF Section 1.7, Hydro One refined the transmission capital investment plan based on the results of its customer engagement. This refinement occurred in conjunction with other factors, including the alignment between asset needs and overall costs, resulting in an investment plan that reflects customer needs and preferences as well as other planning factors.

2.1.4.3 ASSET MANAGEMENT PROCESS

Hydro One's asset management goal is to monitor system assets and determine the appropriate timing of asset maintenance and capital investments throughout the asset lifecycle. This approach allows Hydro One to manage risks and to support Hydro One's Strategic Priorities, customer and operational needs, and RRF outcomes, while managing total cost and customer rate impacts.

The asset management process provides the foundation for the investment planning process by identifying asset, customer and system needs and developing candidate investments for further evaluation and prioritization. Details of the asset management process can be found in TSP Section 2.7, Investment Planning Process.

Hydro One monitors and assesses the current state of the system and its assets on an ongoing basis. The development of candidate investments is underpinned by a needs assessment considering:

- asset condition,
- customer needs and preferences,
- system and operational needs (including regional and bulk planning considerations), and
- external and other influences.

Hydro One performs an asset needs assessment to identify potential candidate investments and collect the data necessary to evaluate and prioritize investments based on risk mitigation, risk spend efficiency, and contribution to desired outcomes. This includes condition, criticality, utilization and performance.

Understanding customer needs is critical to Hydro One's business and investment planning. Ongoing customer processes help the company proactively identify both existing and new customer needs and incorporate them into the investment plan.

In addition to addressing the failure risk arising from deteriorated poor condition assets, Hydro One ensures that new and existing customer and power system needs are met, and that the transmission system delivers adequate and reliable supply to customers. This is done by meeting current and anticipated demands from the connection of load/generation customers. These system needs are identified and assessed by Hydro One in conjunction with customers, the IESO and LDCs under the regional planning process or by the IESO as part of bulk electric system planning.

Based on identified asset, customer and system needs, Hydro One develops a suite of candidate investments for further screening and prioritization. These candidate investments are subsequently assessed and prioritized through the investment planning process. Where appropriate, opportunities to group and bundle related needs, based on logical, functional and geographic groups, are also considered. The information and data collected through the asset management process establish the basis for evaluating and prioritizing investments through the investment planning process, including the assessment of safety, reliability and environmental risks during the scoring stage, as discussed below.

2.1.4.4 INVESTMENT PLANNING PROCESS

Through its investment planning process, Hydro One develops a consistent understanding of risks and investment benefits to cost-effectively deliver high value investments to serve its customers. This process allows the effective assessment and prioritization of candidate investments based on total risk mitigation, risk spend efficiency, and contribution to desired outcomes.

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

Customer-driven outcomes directly impact this process through the definition of consequence scores and risk categories as well as “flags” that reflect priorities and investment benefits that are not fully captured through quantified risk mitigation. Flags are used to account for special considerations and ensure stakeholder perspectives are included in the evaluation of investments. In alignment with RRF outcomes and corporate priorities, flags are clearly defined to reflect mandatory obligations (e.g., compliance driven investments, obligations to regulators, stakeholders or contractual counterparties) or customer preferences and other priorities.

Once candidate investments have been scored and flagged, enterprise-wide calibration sessions occur to ensure comparable and consistent evaluation across investments and lines of business. Based on the risk scores and cost estimates associated with each investment, candidate investments (broken into mandatory versus non-mandatory groups) are ranked according to risk mitigation achieved per dollar. The output is an investment portfolio that is subject to enterprise engagement with portfolio owners and the executing lines of business, to create a realistic and up-to-date plan (i.e., reflecting the latest cost estimates, schedules and investment scope) and account for operational and execution considerations (e.g., resourcing, material availability and outage feasibility).

2.1.4.5 ABILITY TO EXECUTE THE PLAN

Hydro One has demonstrated the ability to successfully deliver large portfolios of capital work. As shown in TSP Section 2.9, Hydro One has been able to effectively and successfully deliver a large and growing capital portfolio. For reference, the portfolio of transmission capital projects in execution phase has grown from $6,180.5M in Q2 2023 to $7,257.0M in Q2 2026, and even with that growth Hydro One has improved in terms of both cost and schedule performance. These outcomes are supported by a strengthened capital delivery framework, including process and governance improvements implemented since the prior rate period. Additional detail on Hydro One's Capital Work Execution Strategy is provided in TSP Section 2.11, including independent benchmarking conducted by E Source. E Source concluded that, relative to a peer group panel of 14 electric utilities across North America, Hydro One is second quartile or better in 9 of 10 performance domains.[15]

Hydro One closely tracks year-to-date expenditures and accomplishments as well as projected year-end expenditures. To stay within the approved 2023-2027 capital funding envelope, Hydro One has actively reprioritized its portfolio to focus on the highest priority and non-discretionary work while maintaining overall adherence to approved funding levels. This outcome reflects prudent financial and portfolio management in the context of material changes since OEB approval, including both increased scope and sustained cost pressures.

[15] E Source, *Transmission Capital Project Execution Review*, prepared for Hydro One Networks Inc, June 2026, filed as Attachment 1 to B-02-01_2.03 TSP – Benchmarking and Other Studies.

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SECTION 2.2 – TSP – ASSET INFORMATION AND LIFECYCLE STRATEGIES

2.2.1 INTRODUCTION

TSP Section 2.2 presents information on the major transmission station and line components that comprise the transmission system of Hydro One and Hydro One Sault Ste. Marie LP (HOSSM). Information on these transmission components includes a description and purpose of the component; demographic, condition and performance information; and lifecycle strategy, including approaches to maintenance and replacement. All information presented is current as of December 31, 2025.

Transmission components presented in this section include:

Table 1 - Transmission Components Presented in TSP Section 2.2

Transmission Station Components	Transmission Line Components
• Transformers; • Breakers; • protection systems; • automation systems; • power system telecom; and • other station assets.	• overhead conductors; • underground cables; • structures and foundations; • insulators; • rights of way; • shieldwires; and • other line components.

Across transmission components, Hydro One applies a consistent lifecycle strategy that uses asset-specific information to inform maintenance or replacement decisions. For assets where direct condition assessment is performed, condition is the primary driver of decisions, while Expected Service Life (ESL) of an asset is used to inform maintenance/monitoring rather than replacement timing. For assets where direct condition assessment is not feasible, such as certain protection devices, lifecycle decisions are informed by factors such as ESL, obsolescence, vendor support, availability of spares, and known systemic risks. While the specific application of these factors varies by asset type, the overall approach supports prudent management of the transmission system.

The asset condition and lifecycle information in this section provides the technical context for the proposed investments included in TSP Sections 2.8 and 2.12.

2.2.1.1 ASSET CONDITION

Condition-based renewal is the cornerstone of Hydro One's asset management and investment planning processes, as discussed in SPF Section 1.7, Investment Planning Process, and TSP Section 2.7, Investment Planning Process. Condition degradation leads to elevated risk of failure. If left unmitigated, such risk could materialize in failures of critical transmission system components and result in significant safety or environmental consequences and have adverse impacts on system operation and performance, and therefore customers. As the steward of transmission assets that are indispensable to the people and economy of Ontario, Hydro One must address assets identified to be in poor condition before unacceptable safety, environmental or reliability impacts manifest.

As the primary driver of replacement decisions, asset condition is verified through the asset risk-based assessment process prior to any replacement investments being undertaken. Where condition assessment is not feasible given the nature of particular assets (e.g., protection devices), assessments are based on factors such as known systemic defects, ESL, availability of spares and vendor support, and/or obsolescence.

Asset condition is generally categorized as:

- **Good**: These assets are new or show minimal signs of deterioration.
- **Fair**: These assets are experiencing deterioration, and their condition is monitored for further deterioration.
- **Poor**: Assets that have deteriorated to a point where they can no longer provide the intended functionality or service.
- **Needs Assessment**: Assets with no or outdated condition data.

As discussed below, ESL is useful as a trigger for condition assessments of older assets and a population-level indicator of asset demographics. ESL or age is not a driver for replacement. Similarly, reliability performance (which is a lagging indicator of asset condition) cannot replace condition as the primary basis for renewal investments,

particularly on a transmission system that must be managed to avoid run-to-fail scenarios and that reflects design redundancies to avoid customer interruptions in contingencies.

For major Hydro One transmission assets, Figure 1 shows the percentage of the population in poor condition at the end of 2016, 2018, 2020, and 2025 (current and previous rate filing condition data). Asset condition trends indicate increasing risk across the transmission system, with the most significant deterioration observed in transformers and wood structures. Poor-condition transformers increased from 16% in 2016 to 29% in 2025, reflecting a materially aging fleet and a growing reliability risk. Transformer failures reduce station redundancy, increase loading on remaining units, and elevate the likelihood of cascading outages.

Breakers remain relatively stable (between 9–11% poor condition); however, approximately 44% of the fleet is obsolete, increasing long-term operational risk due to declining vendor support and spare parts availability. Protection systems remain consistently high-risk, with about 27% of assets beyond expected service life, increasing the likelihood of misoperations and compliance risk.

Conductor conditions have also degraded, increasing from 9% poor condition in 2016 to 14% in 2020, with only a partial recovery to 11% in 2025. Conductor health remains below historical levels, heightening susceptibility to mechanical failures and weather-driven outages.

Wood structures show a pronounced decline, with poor-condition assets rising from 12% to 19% over the same period, signaling an aging pole population and a widening renewal gap. This significantly increases the risk of structural failures, safety hazards, and weather-related outages.

Overall, the growing proportion of poor condition and obsolete assets is increasing the risk of equipment failures, misoperations, extended outages, and reduced operational flexibility, ultimately elevating the risk of customer interruptions.

Leaving poor condition assets unaddressed will lead to elevated risks for safety (e.g., failed overhead line components falling onto publicly accessible areas), the environment (e.g. transformer oil leaks), and reliability (e.g., failed components increasing operational risk or unplanned customer outages). In addition, unplanned equipment outages may affect Hydro One's ability to obtain planned outages, potentially resulting in the cancellation and rescheduling of capital investments and maintenance work. This can delay replacements, and preventive and corrective maintenance, increasing the risk of asset failure and further compounding the aforementioned risks.

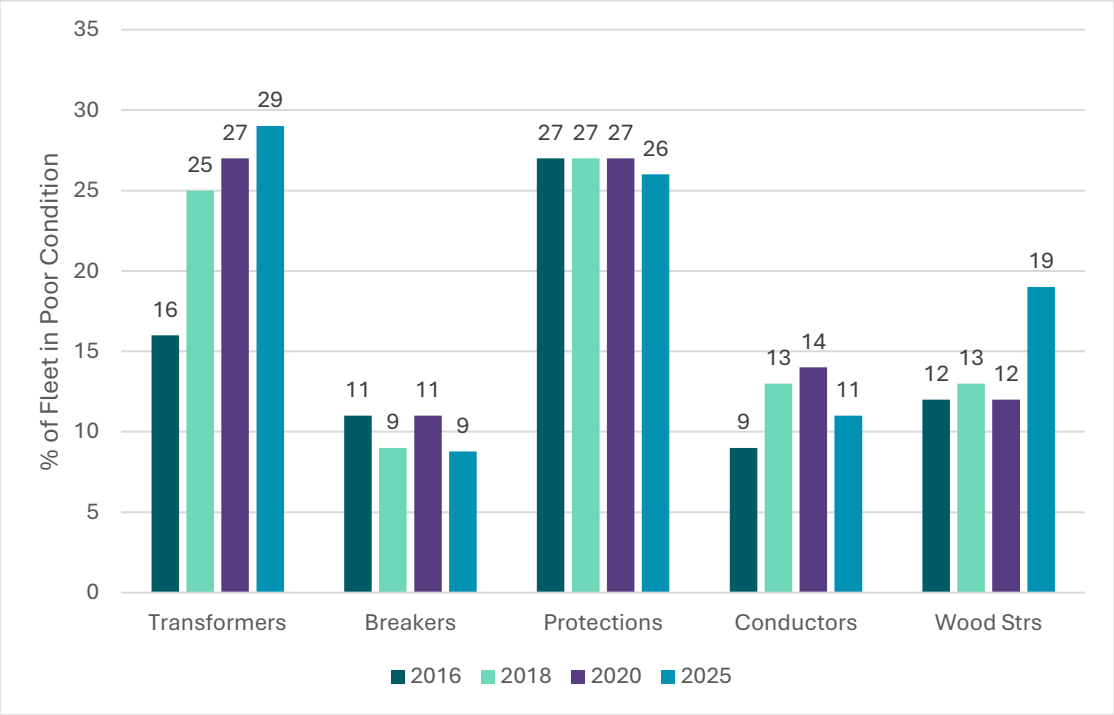

Figure 1: Percentage of Major Hydro One Transmission Components in Poor Condition

Table 2 presents the current condition assessment of HOSSM's major transmission assets based on Hydro One's condition assessment methodology.

Table 2 - Percentage of Major HOSSM Components in Poor Condition

HOSSM Component	Poor Condition (% of Fleet)
Transformers	6%
Circuit Breakers	17%
Protection System	1%
Conductors	0%
Wood Pole Structures	12%

2.2.1.2 ASSET DEMOGRAPHICS

The transmission system is comprised of thousands of components across Ontario. Table 3 below summarizes the demographic profile of the major transmission components of Hydro One and HOSSM.

Table 3 - Hydro One and HOSSM Transmission Component Demographics

Component	Hydro One			HOSSM		
	Quantity	Avg. Age (Years)	Beyond ESL	Quantity	Avg. Age (Years)	Beyond ESL
Transformers	722	29	170	16	39	1
Circuit Breakers	4,691	28	808	107	24	17
Protection Systems	12,748	21	3,329	229	14	10
Overhead Conductors (km)	28,488	58	3,016	471	39	0
Wood Pole Structures	38,550	36	11,270	2,480	30	50

ESL is defined as the average number of years that an asset is expected to operate safely and reliably under normal system conditions and is determined with reference to manufacturer guidelines and Hydro One's historical asset retirement data. ESL or age does not drive replacement investments but can be a useful screening tool for gauging overall asset demographics at the fleet level and allocating condition-assessment resources more efficiently. However, in limited cases the nature of particular assets (e.g., protection devices) means that condition cannot be tested, and ESL-based lifecycle management is necessary, consistent with industry practices.

The longer an asset has been in service, the more cumulative deterioration accrues from its ongoing use and environmental exposure (weather); thus, these assets present greater condition deterioration compared to younger assets. Hydro One uses ESL as a general guideline at the fleet level to inform the need and timing for asset condition assessments (discussed in Exhibit E-02-02, Transmission Sustainment OM&A). ESL also helps Hydro One anticipate the level of testing and inspection needed for aging asset populations and provides insight into the potential scale of future replacement needs over the long term, noting that actual replacements are driven by condition assessments.

2.2.1.3 ASSET PERFORMANCE

Transmission system reliability relating to asset outages, as measured by assessing the frequency and duration of unplanned (forced) outages, and customer interruptions, measured by delivery point (DP) interruptions, are lagging indicators of asset condition and the impact of renewal investments (or the absence thereof). Since major network assets must be renewed on a predictive basis (based on condition assessment) to avoid run-to-failure scenarios, lagging performance trends cannot reasonably replace condition-based assessments of investment needs. Moreover, given that Hydro One's transmission network is largely configured/designed to ensure supply redundancy, the loss of a network element will generally not result in customer (DP) interruptions and thus have little impact on reliability metrics related to DP performance. However, even if an equipment outage does not result in customer interruptions, forced outages can have other impacts on Hydro One's transmission system, including reduced redundancy, increased asset deterioration, and cancellation or rescheduling of planned outages for maintenance, repair and replacement work. The rescheduling or delay of planned work can result in the re-prioritization of projects, increased likelihood of failures, subsequent safety, environmental and reliability risks, and additional costs. Further details on system reliability can be found in TSP Section 2.4, Transmission System Reliability.

Assets in poor condition can lead to performance issues but are not the only cause of outages. At the individual asset level, forced outages can be caused by a number of issues, including animal contact and weather, and therefore may not always be readily attributable to or directly indicative of asset condition. As such, making investment decisions based

solely on such performance statistics (as opposed to a robust investment approach driven by condition) may not address the underlying condition issues impacting performance and posing safety, reliability or environmental risks.

For these reasons, Hydro One does not generally rely on historical performance trends to plan future investments, nor can it afford to allow failures to increase and customer reliability to decline over time before addressing poor condition assets through suddenly escalated capital investments. By the time reliability starts to deteriorate for dual-supplied DPs, equipment performance would have already unacceptably worsened, with an associated impact on customer delivery continuity, system operability, and potentially public safety. Even in the absence of notable reliability deterioration, undue delay in replacing a major network asset (e.g. one of two transformers at a DESN station) in poor condition could mean that the asset must be counted on to carry significantly higher loading in an N-1 scenario (e.g. if the other transformer at the DESN station is out of service). This could result in a catastrophic failure of a highly loaded and poor condition asset with cascading impacts on customers and public safety. Examples include Claireville T15 exhibiting severe gassing during the T14 replacement process and the failure of Alliston T4 during the replacement of T3.

Nonetheless, Hydro One closely monitors DP and asset performance to ensure that customers receive the appropriate level of service and that performance issues requiring urgent resolution or planned corrective actions are effectively identified and addressed. In some cases, performance issues may be symptomatic of systemic defects, like the manufacturing issues related to certain types of porcelain insulators (see Subsection 2.2.4.4, Insulators, below). In those cases, Hydro One will assess the need to take targeted planned action.

The performance data provided in the following subsections represent both the Hydro One and HOSSM networks. Historical results are presented for the most recent ten-year period for Hydro One and seven-year period beginning in 2019 for HOSSM[1].

[1] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

2.2.1.4 ASSET LIFECYCLE

Lifecycle costs of transmission assets are the total costs of an asset throughout its useful life. The lifecycle management approach maximizes benefits to Hydro One and its customers during the asset's service life, while balancing asset performance (including condition) and risks to Hydro One's business objectives.

Based on this identified lifecycle management approach, Hydro One's lifecycle optimization policy describes various processes, procedures, and decision-making points relating to the management of transmission assets (e.g. planning, procurement, maintenance). Hydro One strives to ensure that all relevant processes and procedures are aligned with its optimization policy so that transmission assets are managed using a consistent approach.

Asset-specific strategies for transmission assets are based on the lifecycle management and optimization approach. These strategies include the following, but are not limited to:

- replacement approach and criteria (based on demand or planned replacement, condition, technical obsolescence, environmental and other factors);
- approach to optimize repair versus replacement;
- public and employee safety;
- maintenance criteria (e.g. preventive, corrective, time-based, condition-based, predictive; regulatory);
- tools and training requirements;
- operational criteria and constraints that can impact asset life;
- spare parts requirements (entire units or specific components); and
- consideration for standardization of assets to optimize lifecycle costs and improve productivity.

Asset-specific strategies are reviewed periodically with subject matter experts and updated as needed. The lifecycle management strategy for each asset class must be considered from an overall power system perspective and cannot be considered in isolation. The strategy includes an evaluation of the failure modes, causes of individual component failures, consequences of asset failure, impacts on system performance and other corporate strategic objectives, such as health and safety and the environment.

Asset information, which includes condition information, is reviewed by subject matter experts to ensure quality and accuracy, which is used for the refinement and further development of the asset-specific strategies. As part of the review, subject matter experts may determine that some assets require replacement due to new or increased demands on the system (such as higher load growth or increased generation connections) introduced partway through the lifecycle of the asset. For example, if a customer requests a larger capacity transformer due to forecasted load growth, Hydro One will accommodate the request and the customer will be required to pay a capital contribution. In accordance with Section 6.3, Cost Responsibility for New and Modified Connections, of the Transmission System Code, the capital contribution will cover the difference in costs between the standard transformer that Hydro One would plan to install when the existing transformer reached its end of life, and the larger capacity transformer required to satisfy the customer request for incremental capacity.

Asset utilization may be another factor used to evaluate asset replacement. For example, transformer asset utilization considers the peak loading of the transformer compared to the transformer's capacity. There are circumstances where a transformer can be operated above its designed ratings or beyond its limited time rating for a period of time. If these situations result in operating constraints, the unit may be considered as a candidate for replacement. Hydro One will also review the asset's historical loading and may decide to address the system's need with a like-for-like replacement or to install a new standard asset. Typically, Hydro One replaces assets on a like-for-like basis. With respect to transformers, as an example, Hydro One considers the following factors before the decision to replace is made:

- any customer requests;
- the option of utilizing a different type and size of transformer to standardize the fleet, which would reduce the number of operating spares required while considering the implication of losses; and
- reconfiguring or right-sizing the station from a non-standard four-transformer layout to a two-transformer layout to reduce asset count and footprint and increase operational efficiency.

2.2.2 ASSET COMPONENT INFORMATION – TRANSMISSION STATIONS

This section discusses the main assets that are found in transmission stations, including transformers, breakers, protection schemes, control and monitoring equipment, power system telecom equipment, switches, capacitor banks, instrument transformers, ancillary equipment and civil structures.

2.2.2.1 TRANSFORMERS

2.2.2.1.1 ASSET DESCRIPTION / PURPOSE

Transformers are used in power systems to convert power from one voltage level to another. Transformer designs vary by type, class and function, as summarized in Table 4 below:

Table 4 - Transformer Fleet Description

	Type	Description
	Step-down	Step-down transformers convert transmission voltages (50 kV or higher) to distribution voltages (less than 50 kV)
	Autotransformer	Autotransformers are a special type of power transformer, used to cost-effectively transform voltages and currents between transmission system voltage levels higher than 100 kV.
	Phase Shifter	Phase shifting transformers are employed in selected locations to optimize power flows across international tie-lines.
	Regulator	Regulator transformers provide voltage regulation through the use of an internal tap changer.

	Reactor	Shunt reactors are single-winding devices that absorb reactive power from the system as a way of controlling voltage and increasing the energy efficiency of the system.

2.2.2.1.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.2.1.3 ASSET DEMOGRAPHICS

As of the end of 2025, Hydro One had 722 transmission class transformers in service (with 750 transformer tanks), as summarized in Table 5 below. The transformer fleet increased by one unit[2] since the last rate application. The number of transformers beyond ESL (which ranges between 40 to 60 years) decreased to 170 units (23.5% of the fleet) since the last rate application at 176 transformers (24% of the fleet) and the average age of the fleet decreased to 28.5 years from 30.

Table 5 - Hydro One - Transformer Demographics

Type	Voltage	Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
Step-down	500 kV	1	15	40	0
	230 kV – 2 winding	182	32.2	50	52
	230 kV – 3 winding	138	27.6	40	31
	115 kV – 3 winding	109	27.8	40	33
	115 kV – 2 winding	144	21.6	60	11
Auto	500 kV	42	25.8	40	8
	345 kV	3	28.7	40	2
	230 kV	87	36.5	50	30
Phase Shifter	230 kV	5	22.0	40	1
Regulator	230 kV	2	38.5	40	1
	115 kV	1	76.0	50	1
Reactor	500 kV	4	7.2	30	0
	230 kV	3	4.7	30	0
	115 kV	1	24.0	30	0
Total	-	**722**	**-**	**-**	**170**

[2] EB-2021-0110 TSP 2.2 Table 2: quantity: 721, average age: 30.3, beyond ESL: 176.

HOSSM has 16 transmission transformers in service, as summarized in Table 6, of which one operates beyond its ESL.

Table 6 - HOSSM - Transformer Demographics

Type	Voltage	Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
Step-down	230 kV	2	20.5	50	0
	115 kV	11	46.2	60	0
Auto	230 kV	3	25.0	50	1
Total	**-**	**16**	**-**	**-**	**1**

2.2.2.1.4 ASSET CONDITION

Transformer condition is a leading indicator of transformer performance. Condition is determined through preventive maintenance including diagnostic testing and inspections (discussed below). The overall condition of Hydro One's fleet of transformers is summarized in Figure 2. Relative to the prior rate application, there has been slight increase in the total number of poor condition transformers from 198 units (27% of the fleet) to 209 units (29% of the fleet). Over the same period, the proportion of good condition transformers remained at approximately around 61%.

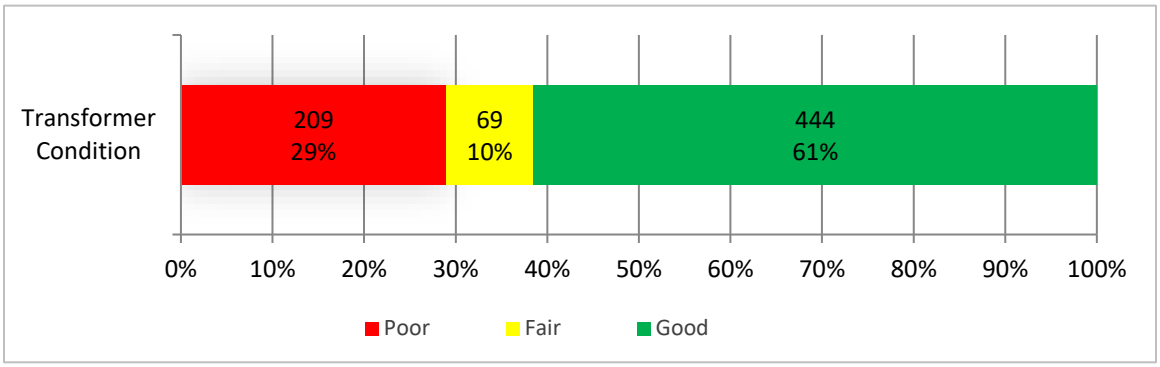

Figure 2: Hydro One - Transformer Condition

Figure 3 presents the condition of HOSSM's transformer fleet, of which 75% is in good condition, 19% is in fair condition and 6% is in poor condition.

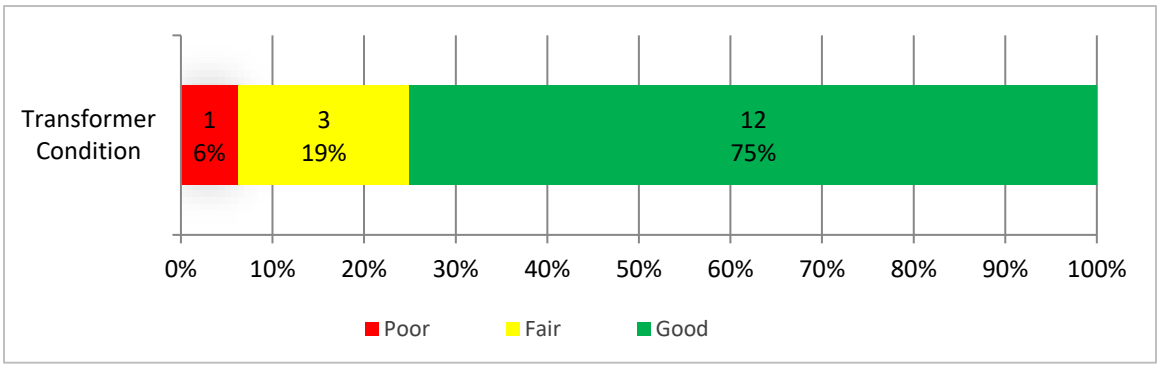

Figure 3: HOSSM - Transformer Condition

Transformer condition can be impacted by several factors including loading history (i.e. the amount of power it must transform), age, weather exposure, and operating conditions. If a transformer experiencing some deterioration is highly loaded, it is likely to deteriorate faster than if it carries a lower load.

A transformer's load profile can depend on the station's design and the load the transformer is expected to carry during normal and temporary conditions. In a station with two transformers, one of the transformers may be required to temporarily carry a higher load as a result of an extended (planned or forced) outage of the companion transformer. Under this scenario, the remaining in-service transformer (which likely has characteristics

that are similar to the companion unit, and both have been subjected to similar environmental conditions and loading) would be required to bear the full load of both transformers and therefore experience further condition deterioration as a result.

The overall condition of a transmission transformer is evaluated based on a detailed condition assessment using the most recent condition data as well as historical data relating to four main indicators: (i) insulation deterioration within the main tank, (ii) oil leaks, (iii) cooling system failure, and (iv) tap changer malfunction.

i. **Insulation deterioration within the main tank** is one of the key indicators of transformer condition and is an irreversible occurrence as a function of time and operating temperature. The condition of the main tank can be assessed through general oil tests, including (i) standard oil tests, (ii) dissolved gas analysis (DGA) to identify thermal and electrical faults, and (iii) Doble tests and furan analysis to measure overall insulation degradation. Replacement or top-up of the oil (e.g., in response to oil leaks) may temporarily restore some of the insulating characteristics or reduce moisture content and give rise to general oil test results that mask the full extent of main tank condition issues. It is important to recognize that the deteriorated physical condition of the insulation cannot be repaired or reversed and that a point-in-time oil test may not in itself reliably inform the condition assessment of the transformer.

ii. **Oil leaks** from poor joints and gasket deterioration also impact transformer condition. Oil leaks from transformers could adversely impact the environment, leading to potentially costly remediation and repairs. It can also lead to performance issues due to low oil levels (which may result in planned or unplanned outages) and moisture penetrating the transformer (which damages its insulation, accelerates deterioration and causes failures). Approximately 45% of Hydro One Transmission's transformer tank fleet has been confirmed by visual inspections to have oil leaks, including 6% being classified as major leakers. New leaks appear in approximately 1% of the fleet per year over the longer term, most commonly due to gasket deterioration.

iii. **Cooling system failures** also impact the overall condition of transformers, which rely on fans, pumps and radiators for cooling and to achieve a higher load limit. A non-functional cooling system forces the transformer to operate at reduced loading capacity, impairing performance or causing unplanned outages, both of which may impact system load transfer capability. Outages caused by transformer cooling systems may reduce station capacity and jeopardize supply adequacy to customer load.

iv. **Tap changers** provide voltage regulation in response to loading changes. Transformer condition and performance can be affected by tap changer mechanical and operational issues, including mechanical fatigue on sub-components and deficiencies with current carrying components. Such issues are becoming more common due to significant fluctuations in demand as well as variation in voltages across the system. In particular, the variability of wind and solar generation leads to changes in flow magnitude and direction and requires the tap changers to sustain acceptable system voltage levels.

As shown in Figure 2, out of a total of 722 transmission transformers in-service at the end of 2025, 209 transformers were deemed to be in poor condition based on a combination of main tank deterioration, oil leaks, cooling system failures, tap changer malfunction, and defect reports.

Among the 42 units of 500 kV autotransformers, 13 are equipped with Tank Pressure Relief Systems (TPRS) that rely on rupture discs to relieve pressure from internal arcing. Several of these rupture discs (520 pieces in total) are showing signs of deterioration and must be replaced promptly once identified to prevent improper transformer operation. A ruptured disc will force the transformer out of service, as demonstrated by the Trafalgar T14 TPRS disc rupture event on May 12, 2025.

2.2.2.1.5 ASSET PERFORMANCE

Transformer performance may be measured by assessing the duration and frequency of forced outages caused by the transformer or its auxiliary components, which result in the automatic or manual removal of the transformer from service. Transformers may be forced out of service for many reasons including complete failure of the unit, oil leaks, tap changer breakdown or bushing problems. Outages caused by the complete failure of a transformer are a subset of the overall forced outages presented below.

Transformer caused outages may not cause a customer interruption due to the redundancy within a station, but they do cause the station to lose its redundancy during the outage, elevate supply risk to connected customers, result in higher loading stress on other station transformers, and potentially result in the cancellation of planned outages that are required to execute maintenance work. The forced outage statistics below include transformer outages that impact customers as well as those that do not due to station supply redundancy. Further information on delivery point reliability affecting customers may be found at TSP Section 2.5, Performance Measurement and Outcomes.

As shown in Figure 4, the duration of transformer forced outages has fluctuated since 2016. Major transformer failures have been key drivers of prolonged outage durations. For example, the 2018 failure of Finch TS T2 (a 230–28 kV step-down transformer) resulted in an explosion, fire, and oil leakage, requiring a full replacement that took one year due to site cleanup, removal, and installation activities. Similarly, Hawthorne T3 (a 500–230 kV autotransformer) failed in 2022 after severe gassing beyond repair and required a demand replacement that took ten months. In the same year, Hanover T2 (a 115–44 kV step-down transformer) experienced ULTC burnout and irreparable oil leakage on a significantly aged unit, resulting in a replacement process lasting more than one year, including removal, installation at a new site, and MTU mobilization.

Each time a transformer fails, and redundancy is lost for months, the system remains exposed because any subsequent failure of the companion transformer can lead to severe consequences for load and customers. Therefore, minimizing unplanned transformer failures is critically important to maintaining system reliability and customer service.

Transformer outages can be caused by several different causes, including transformer condition issues, animal contact, or auxiliary components. The duration and frequency of outages are used to show equipment performance over time, but do not directly drive investment decisions given that performance is a lagging outcome relative to actual asset conditions.

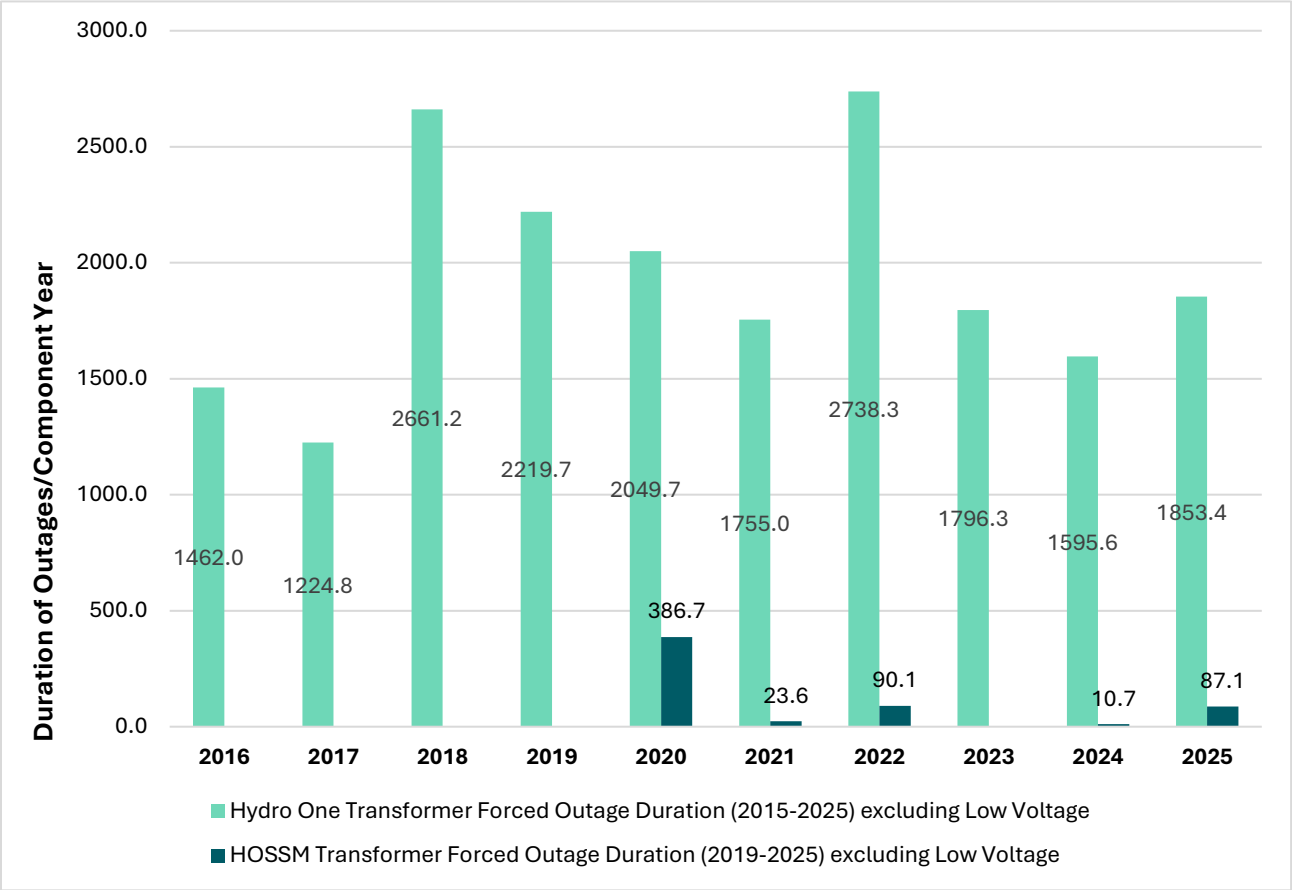

Figure 4: Transformer Forced Outage Duration Excluding Low Voltage

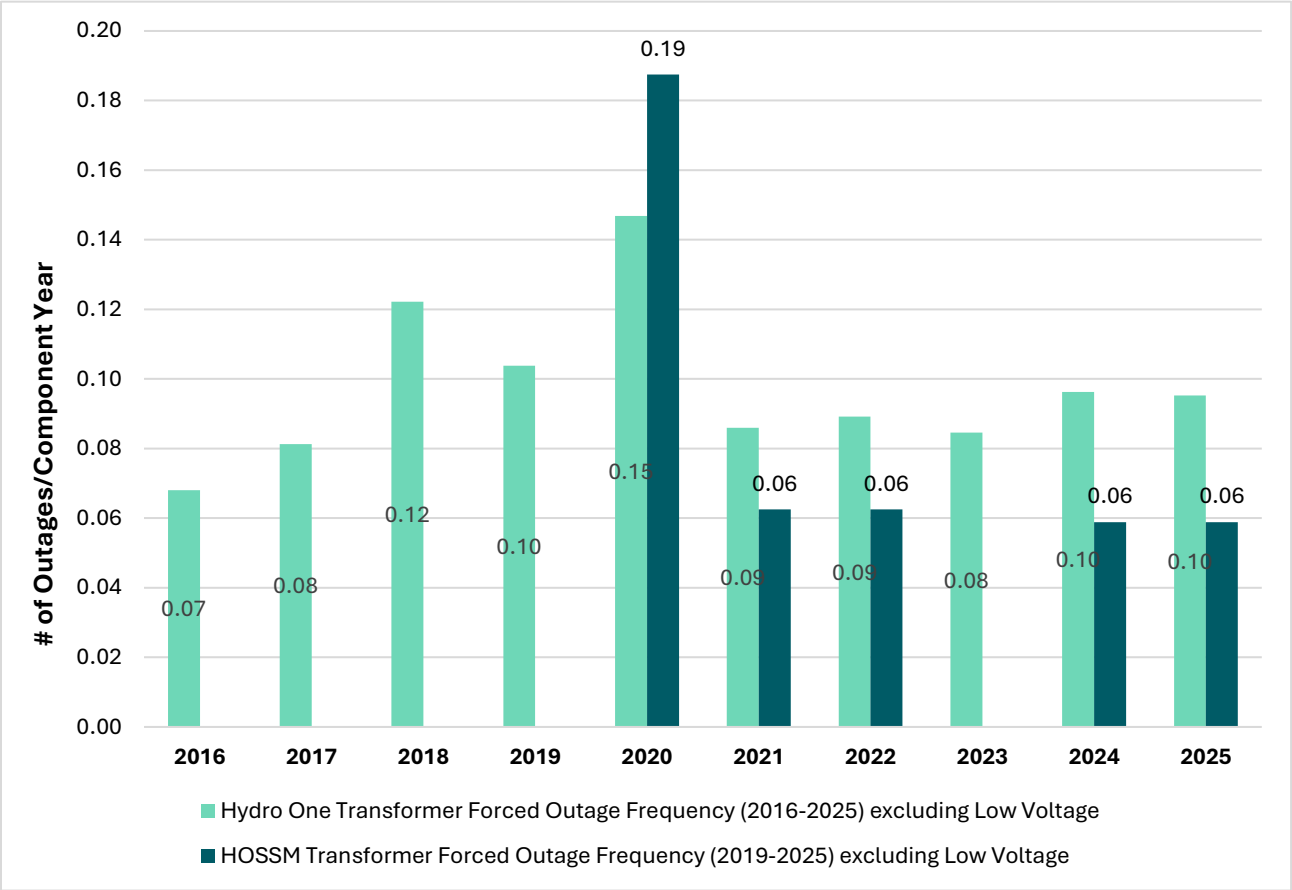

Figure 5: Transformer Forced Outage Frequency Excluding Low Voltage

The transformer fleet's failure rate is shown in Figure 6. Historically, the system has experienced an average of three transformer failures per year requiring full replacement. In recent years, however, this failure rate has declined, largely due to enhanced maintenance practices and improvements to the demand-replacement strategy. This strategy expanded the scope of replacements to include not only failed units but also transformers identified as being at imminent risk of failure. Proactively removing these high-risk assets has significantly reduced the likelihood of failures ranging from severe gassing and irreparable oil leaks to catastrophic events. A notable example is the 2011 failures of Richview T7 and T8, where both transformers were engulfed in fire, producing heavy smoke that impaired visibility on Highway 401 during rush hour and requiring emergency replacement to restore power. Incidents of this scale underscore that, while the recent reduction in failures is encouraging, the inherent risk remains substantial. Even

a single catastrophic transformer failure can create serious safety hazards and pose a major threat to bulk power system reliability.

Despite the improvements achieved, the system remains vulnerable. When a transformer fails, redundancy is lost for months, exposing the companion transformer to elevated loading and increased stress. Any subsequent failure during this period could lead to severe customer impacts, extended outages, and public safety risks. Therefore, continued vigilance through condition-based maintenance, timely asset renewal, and careful monitoring of aging units is critical to preventing high-impact failures and preserving overall system resilience.

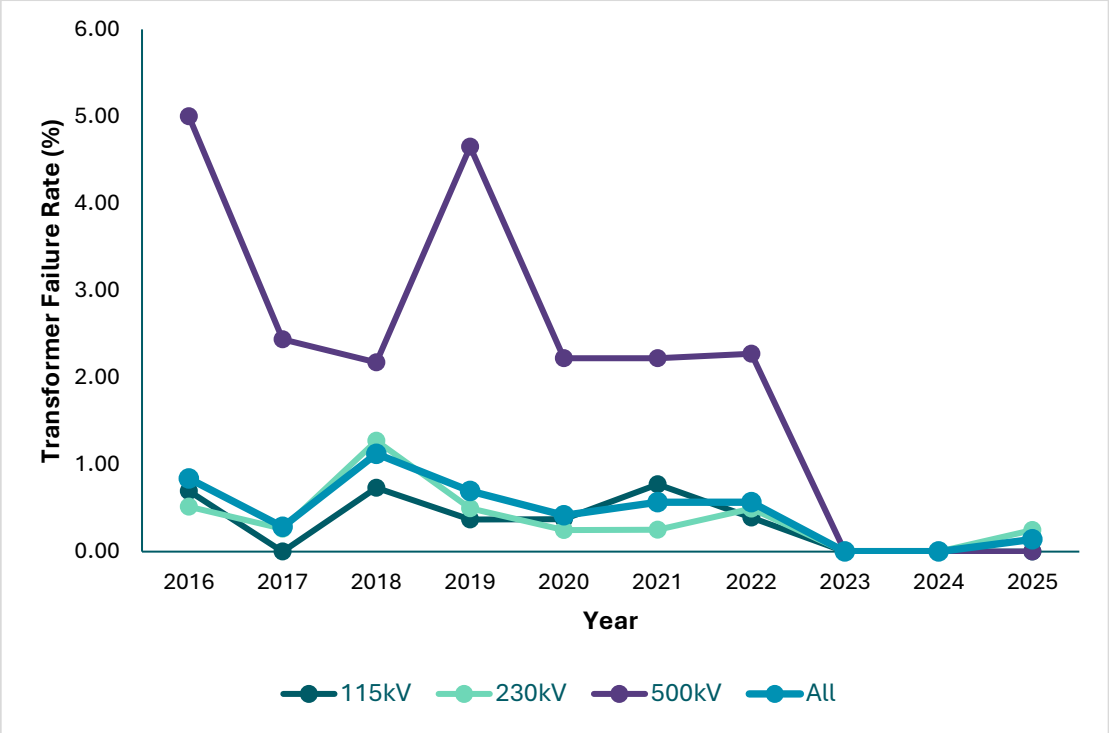

Figure 6: Transformer Annual Failure Rate

Table 7 - Hydro One Transformer Failures

Year	Voltage		
	115 kV	230 kV	500 kV
2016	2	2	2
2017	0	1	1
2018	2	5	1
2019	1	2	2
2020	1	1	1
2021	2	1	1
2022	1	2	1
2023	0	0	0
2024	0	0	0
2025	0	1	0

2.2.2.1.6 ASSET LIFECYCLE

2.2.2.1.6.1 INSPECTION AND MAINTENANCE PRACTICES

Hydro One performs preventive maintenance and corrective maintenance activities on transformers to assess condition, monitor deterioration, manage maintenance schedules and remediate deficiencies when it is technically feasible and economical. Maintenance practices are continuously updated to employ the best industry practices. Transformer maintenance expenditure details may be found at Exhibit E-02-02, Transmission Sustainment OM&A.

Preventive Maintenance

Preventive maintenance is planned maintenance of transformers with the goal of preventing degradation and failure. This work consists of time-based activities that are compiled from sources including the manufacturer's manual, industry technical reports and Hydro One's operating experience. During this maintenance, condition data is collected to evaluate the health of the equipment and determine whether corrective work is required. Traditional transformer maintenance involves sampling transformer insulating oil annually.

Meanwhile, Hydro One has been applying modern technology and innovation ideas to improve the efficiency and accuracy of preventive maintenance practices. To date, all 500 kV and critical transformers have been installed with DGA on-line monitors. Thus, as the fleet of online monitoring devices expands, more time-based condition data becomes available, allowing maintenance plans to be scheduled based on condition rather than set time intervals.

Condition based maintenance enhances asset prioritization by allowing maintenance activities to be accelerated or deferred based on actual equipment condition rather than a fixed schedule. This approach ensures resources are focused where they are most needed and supports more informed, data driven decision making.
It is important to clarify that condition-based maintenance does not reduce the need and the pacing for transformer replacements. Once a transformer is assessed to be in poor condition, it will still enter the replacement plan.

Hydro One will continue to install and upgrade online DGA monitors, and trial online partial discharge monitors that detect abnormal electrical discharges.

The following transformer Preventive Maintenance activities and schedules apply:

Table 8 - Transformer Inspection and Maintenance Summary

Maintenance	Frequency	Description
Visual Inspection	Bi-annual	Visual and audible deficiency inspection.
Oil Testing	Annual	Analysis of DGA and oil quality to evaluate transformer condition.
Diagnostic Level 1	4 years	Function testing of transformer sub-components to verify correct operation.
Diagnostic Level 2	8 years	Replacement of the Gas Accumulation Relay and associated cable.
Power Factor Test (Doble Test)	4–8 years	Assessment of the transformer and the insulating condition of its bushings.
Selective Intrusive (SI) Inspection	4–8 years	Condition inspection of all internal components, contacts and mechanisms.
Turn Ratio Test	As Required	Testing of the primary to secondary ratio of the transformer to assess tap changer performance, winding condition and connections and other internal faults.
Winding Resistance Test	4–8 years	Testing of the tap changer's performance, winding condition and connections, and other internal faults
TPRS Inspection	4 years	Inspection of rupture discs for signs of deterioration and oil leaks from the system.

Corrective Maintenance

Corrective maintenance is planned or unplanned transformer repairs addressing degrading or failed components. Planned corrective maintenance remediates defects reported during preventive maintenance activities while unplanned corrective maintenance remediates critical defects not discovered during preventive maintenance, and that emerge either due to equipment failure or by field staff observations. Corrective maintenance is completed where remediation is feasible, will preserve (though not extend) the asset's lifespan relative to the expected service life, and ensure continued reliable and safe performance.

Corrective maintenance practices are continuously updated to employ best industry practices. For example, traditional transformer oil leak repairs are invasive, costly and lengthy as they require transformer oil to be removed from the transformer and to be processed prior to refilling. Instead, where feasible, Hydro One uses a sealant injection process that injects sealant between gaskets to repair an oil leak, in cases where it is

feasible and cost effective compared to the traditional oil leak repair approach of replacing the leaking gasket.

The critical transformers are now equipped with DGA online monitors allowing real-time assessments several times per day that trigger condition-based preventive maintenance to be scheduled where condition data justifies the need, and before an unplanned outage or failure occurs. Some DGA monitors include temperature monitors that provide real time loading data as well as utilization history. DGA online monitors have been installed on critical units, which require special monitoring due to suspected defects, or units with very high replacement costs.

The following transformer corrective maintenance activities are commonly performed:

Table 9 - Transformer Corrective Maintenance Summary

Maintenance	Description
Oil Leak Repair	Replacing leaking transformer gaskets, piping, valves and other components.
Tap Changer Repair	Overhauling the transformer tap changer assembly or cleaning the control relay.
Cooling Fan Repair	Replacing transformer cooling fans or cleaning control equipment.
Bushing Replacements	Replacing leaking or failed bushings.

Where repair through corrective maintenance is not feasible, unplanned replacement shall be coordinated as described in TSP Section 2.7, Investment Planning Process. Hydro One's overall approach toward asset replacement (as well as refurbishment) is further discussed below.

2.2.2.1.6.2 ASSET REPLACEMENT AND REFURBISHMENT

Transformer condition is a leading indicator of transformer performance. Hydro One does not run power transformers to failure given their criticality to the integrity of the transmission system and the significant reliability, safety and environmental impact associated with their failures. Transformer failures can result in customer outages or increased loading on other station transformers, oil leaks, and in some cases, transformer

fires. Additionally, an unplanned outage may result in the cancellation or delay of planned maintenance. Hydro One proactively replaces or refurbishes transformers so that the condition issues are resolved before those risks materialize.

Assessments to refurbish or replace transformers are done on an individual basis considering factors such as condition, performance, utilization, demographics, criticality, and environmental factors.

Transformers in poor condition are prioritized for replacement with consideration of those with known manufacturing defects, higher repair costs or those that have undergone short-term repairs to restore functionality but continue to pose a performance risk. Transformers that do not meet replacement criteria (particularly those that have reported severe oil leaks) will be prioritized for refurbishment to preserve their expected service life and reliability.

To mitigate the impact of unplanned transformer failures, spare operating transformers continue to be purchased and stored to support most power transformers that are in service. Furthermore, transmission class mobile transformer units continue to be deployed to reduce the duration of planned and unplanned transformer caused outages.

2.2.2.2 CIRCUIT BREAKERS

2.2.2.2.1 ASSET DESCRIPTION / PURPOSE

A circuit breaker is a mechanical switching device that is capable of carrying and interrupting electrical current under normal and abnormal conditions. During abnormal conditions, circuit breakers are capable of operating rapidly to interrupt high current thereby minimizing its effect on the rest of the power system.

Circuit breakers use a variety of interrupting media that have evolved over time. Hydro One’s circuit breaker fleet has been summarized in Table 10 below according to the interrupting medium used, along with the production and environmental status.

Table 10 - Breaker Fleet Description

	Type	Interruption Medium	Production Status	Safety and Environmental Concerns
	Oil Circuit Breakers (OCB)	Oil	Obsolete	Oil spill
	Air Blast Circuit Breaker (ABCB)	Air	Obsolete	Noise
	Sulfur Hexafluoride (SF6) Breaker	SF_6	Commercially available	SF_6 is a greenhouse gas
	Gas Insulated Switchgear (GIS)	SF_6, Vacuum*	Commercially available	SF_6 is a greenhouse gas
	Metalclad Switchgear	SF_6, Vacuum, Air, Air Magnetic	Commercially available	Arc flash hazard
	Vacuum Breaker	Vacuum	Commercially available	None

** Medium Voltage GIS uses vacuum interrupters as the interrupting medium and SF6 as the insulating medium.*

2.2.2.2.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.2.2.3 ASSET DEMOGRAPHICS

Hydro One has 4,691 High Voltage (HV) and Medium Voltage (MV) breakers in service, as summarized in Table 11. In addition, HOSSM has 107 breakers as summarized in Table 12. The breaker fleet decreased by 65 units[3] since the last rate application as a result of replacing circuit breaker configurations with new configurations that require fewer breakers at certain stations.

The number of breakers beyond ESL has increased since the last rate application from 763 breakers (16% of the fleet) to 808 breakers (17 % of the fleet). The fleet is older overall,

[3] EB-2019-0082 TSP 2.2 Table 6: quantity: 4756, average age: 28 years, beyond ESL: 549.

with the average age increasing by 10% to 30 years[4]. A large number of oil, air blast and metalclad breakers have already reached their ESL with an increasing number of breakers forecast to reach ESL within the next decade.

Table 11 - Hydro One - Breaker Demographics

Type	High Voltage (kV)	Medium Voltage (kV)	Total	Average Age (Years)	ESL (Years)	Beyond ESL
Air Blast Circuit Breaker	48	21	69	53	40	69
GIS	128	0	128	30	40	53
Metalclad	0	710	710	30	40	189
Mixed Gas	1	0	1	1	40	
MVGIS	0	275	275	8	40	3
Oil Breaker	293	1,060	1,353	51	55	490
SF6	949	1,171	2,120	17	40	4
Vacuum	0	35	35	21	40	
Total	**1,419**	**3,272**	**4,691**	**-**	**-**	**808**

Table 12 summarizes HOSSM's breaker fleet, which has an average age of approximately 24 years.

Table 12 - HOSSM - Breaker Demographics

Type	High Voltage (kV)	Medium Voltage (kV)	Total	Average Age (Years)	ESL (Years)	Beyond ESL
Metalclad	0	30	30	33	40	13
Oil Breaker	6	0	6	40	40	4
SF_6	61	2	63	19	40	0
Vacuum	0	8	8	18	40	0
Total	**67**	**40**	**107**	**-**	**-**	**17**

2.2.2.2.4 ASSET CONDITION

Breaker condition is a leading indicator of expected performance. Poor condition breakers can ultimately result in outages that severely impact system stability, the operations of other connected equipment, and employee and public safety. Hydro One proactively manages its breaker fleet to address condition issues before these risks materialize.

[4] Average age is 30 years for the overall fleet.

The condition of the breaker fleet is assessed through preventive maintenance activities, including diagnostic testing and inspections (described below). A summary of Hydro One's and HOSSM's fleet condition is presented in Figure 7 and Figure 8, respectively. Since the last transmission rate application, the number of Hydro One breakers classified as being in poor condition has decreased from 541 (11%) to 403 units (9% of the fleet). The decline is largely attributable to planned asset and targeted component replacement, including the replacement of a significant number of air blast breakers in poor condition. However, this does not necessarily reflect an overall improvement in the fleet, as many breakers are continuing to degrade into the poor condition category. As shown in Figure 8, HOSSM has 18 (17%) units that are in poor condition mainly due obsolescence and declining condition and performance factors.

Circuit breakers use different interrupting mediums such as oil, air, and SF_6 gas to extinguish electric arcs during operation. For air and SF_6 breakers, these gases must be kept at high pressure to work effectively. As breakers age, their O-rings and gaskets deteriorate, leading to SF_6 leaks. When this happens, the internal pressure drops and moisture can enter the equipment. Both reduced pressure and moisture lower the breaker's dielectric strength, weakening its ability to quench arcs. This increases the risk of internal flashover, which in severe cases can result in an explosive breaker failure. These factors contribute to poor breaker condition and may result in a major overhaul or demand replacement.

In addition to condition, the presence of obsolescence can necessitate the replacement of assets that might otherwise remain operational. Obsolescence creates reliability and maintainability risks, such as limited availability of spare parts, discontinued manufacturer support, and the inability to safely or effectively perform modern testing, diagnostics, or repairs. These risks can materially increase the likelihood and consequence of in-service failures over time.

Obsolescence is not limited to assets in poor condition. A meaningful portion of assets in fair or even good condition may no longer be supported by manufacturers and may require replacement due to technology limitations and parts unavailability. As such, obsolescence

remains an important planning driver that supports timely asset renewal to maintain reliability and operational effectiveness. Obsolescence alongside condition, can provide a more comprehensive view of asset health and system risk. This approach ensures that assets with deteriorating condition and those constrained by obsolete designs are addressed proactively, thereby reducing exposure to avoidable failures, extended outage durations, and system resiliency issues.

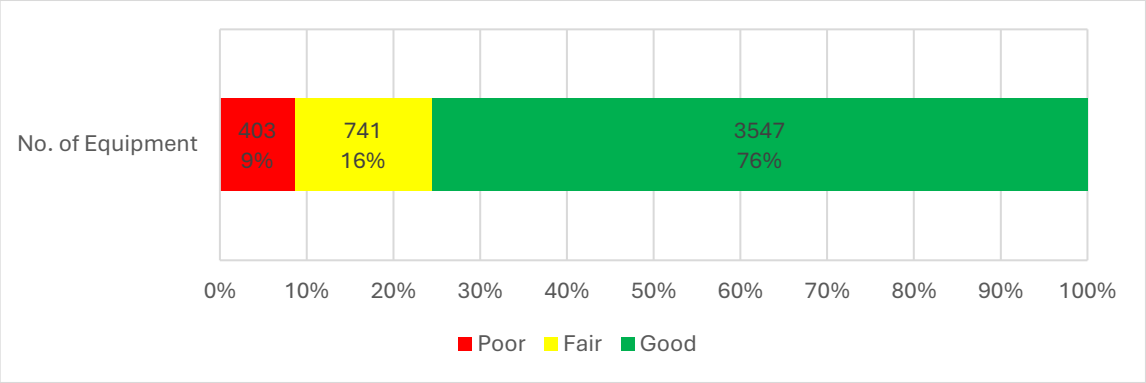

Figure 7: Hydro One – Circuit Breaker Condition

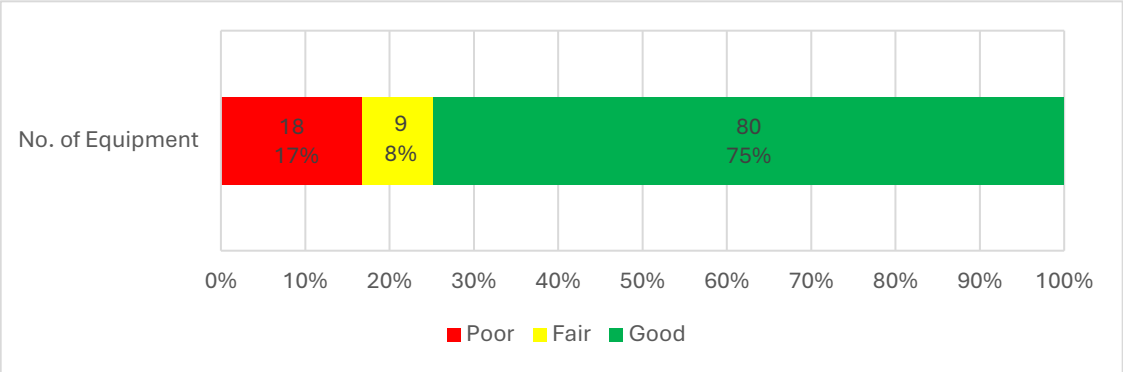

Figure 8: HOSSM – Circuit Breaker Condition

Hydro One has 2,061 breakers, or 44% of the overall fleet, that are considered obsolete, with approximately 545 breakers, or 11% of the overall fleet, no longer supported by vendors and where aftermarket parts are not available or are costly to acquire or fabricate. This is a significant risk factor to the Air Blast circuit breakers, some first generation SF6/GIS circuit breakers, metalclad breakers and oil circuit breakers. Where parts are difficult to procure, specific units are replaced so the decommissioned units can serve as

strategic spares for the remaining in-service fleet, but that is currently not feasible for approximately 11% of the overall fleet.

2.2.2.2.5 ASSET PERFORMANCE

Circuit breaker performance may be measured by assessing the duration and frequency of forced outages caused by the breaker or terminal equipment adjacent to the breaker. These performance measures are presented in Figures 9 and 10. Such outages result in the automatic or manual removal of the breaker from service. Breakers may be forced out of service for many reasons including control component issues, air leaks, gas leaks, operating mechanism issues, moisture content problems and auxiliary equipment malfunctions.

Breaker caused outages may not cause a customer interruption due to the redundancy within a station, but they do cause the station or circuit to lose its redundancy during the outage and elevate supply risk to connected customers. The forced outage statistics below include outages impacting customers and outages that were isolated to the breaker due to station or circuit supply redundancy. Further information on delivery point reliability affecting customers may be found in TSP Section 2.5, Performance Measurement and Outcomes.

The circuit breaker performance measures, which includes the number and duration of forced outages due to circuit breakers, has increased over the past decade with a slightly decreasing trend in the last five years, as illustrated in Figure 9 and Figure 10 below. This overall decrease in recent years is primarily attributed to the number of Air Blast circuit breaker replacements. The relatively high forced outage frequency for a period of years starting in and around 2022 was predominantly due to weather related outages.

Circuit breaker outages can arise from different causes, including circuit breaker condition issues or auxiliary components. The duration and frequency of outages are used to show equipment performance over time, but it is important to recognize that outage statistics – as a lagging indicator of asset condition – are only one of several factors considered when making investment decisions.

Outage duration and frequency were trending lower until 2024 with a recent spike in 2025 primarily due to air leaks on the remaining Air Blast circuit breakers in the system and SF_6 leaks on first generation SF_6 breakers. In 2025 alone, there were 36 SF_6 leak outages on first generation SF_6 breakers. These leak outages are a contributing factor in increasing outage duration and frequency.

While HOSSM's breaker fleet has had poorer performance in recent years, this 90% of this performance was primarily driven by three breakers at Patrick TS, Clergue TS, and Magpie SS that were removed from service. Repairs were unsuccessful and these breakers will remain out of service until replacement units are installed. Excluding these three breakers, the overall performance of the HOSSM breaker fleet has been satisfactory.

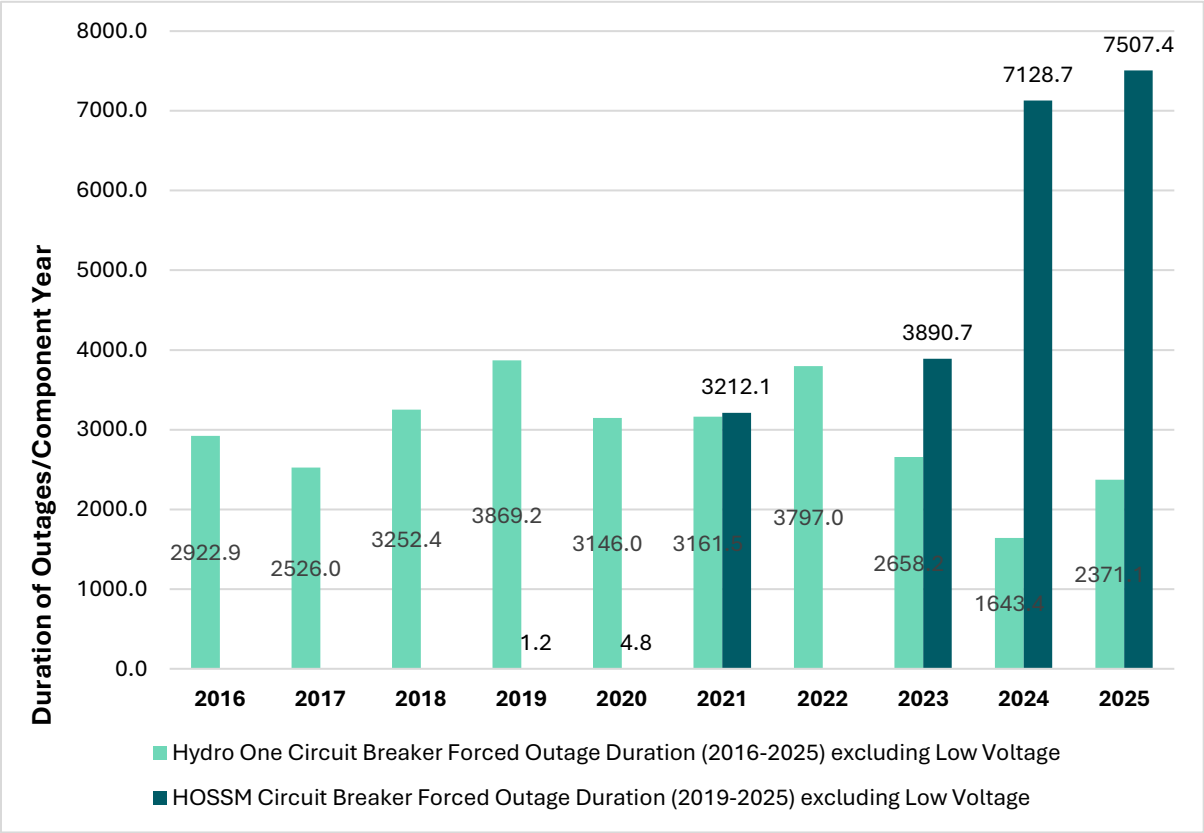

Figure 9: Circuit Breaker Forced Outage Duration Excluding Low Voltage

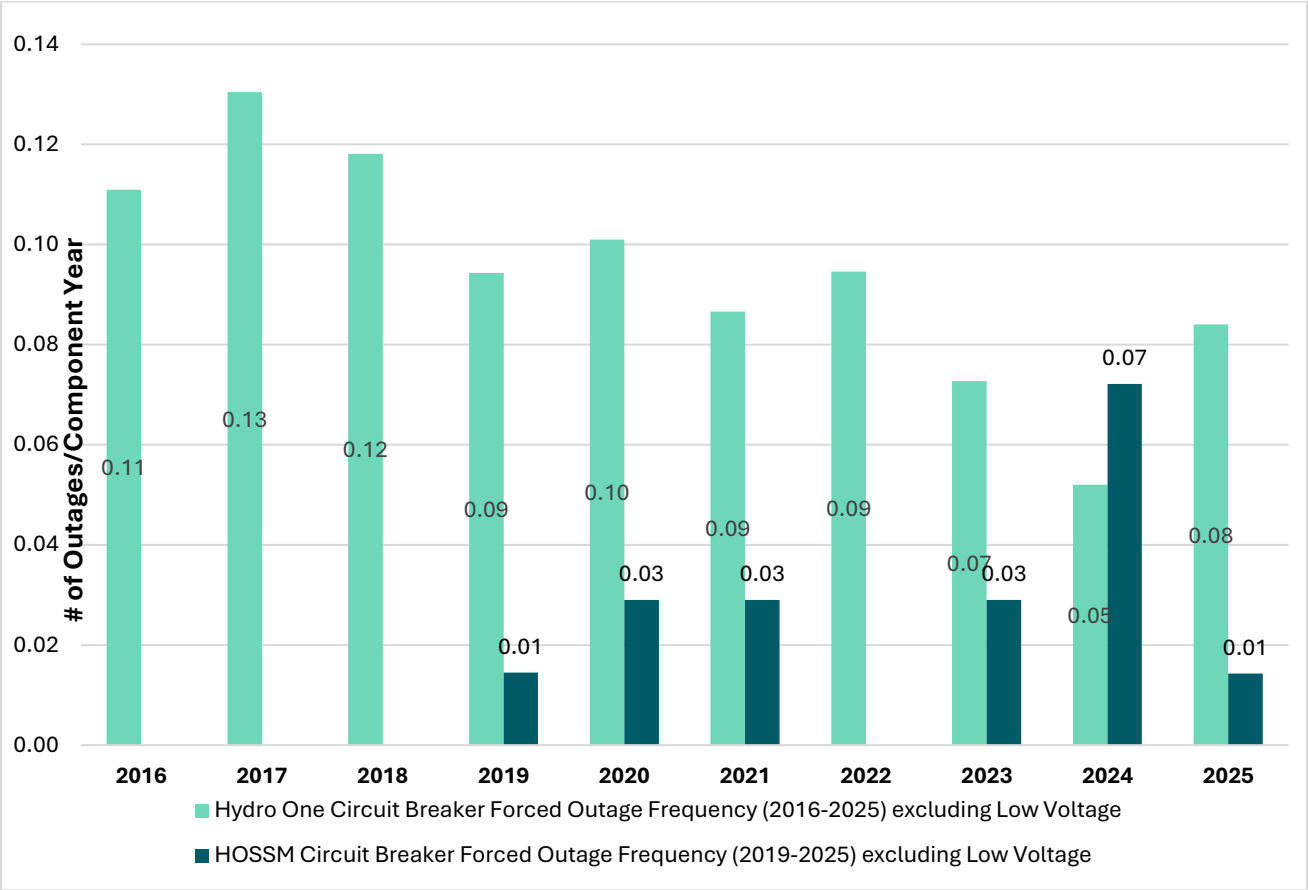

Figure 10: Circuit Breaker Forced Outage Frequency Excluding Low Voltage

Forced outage frequency by breaker type in Figure 11 below illustrates how the strategy of replacing the Air Blast circuit breakers has lowered their related forced outages in recent years, and the recent spike that is shown in 2025 are from the remaining Air Blast circuit breakers that are planned to be replaced in next few years. For example Cherrywood KL27 has more than 10 outages related to fill valve and low air issues in 2025 and more than 16 outages in last 5 years.

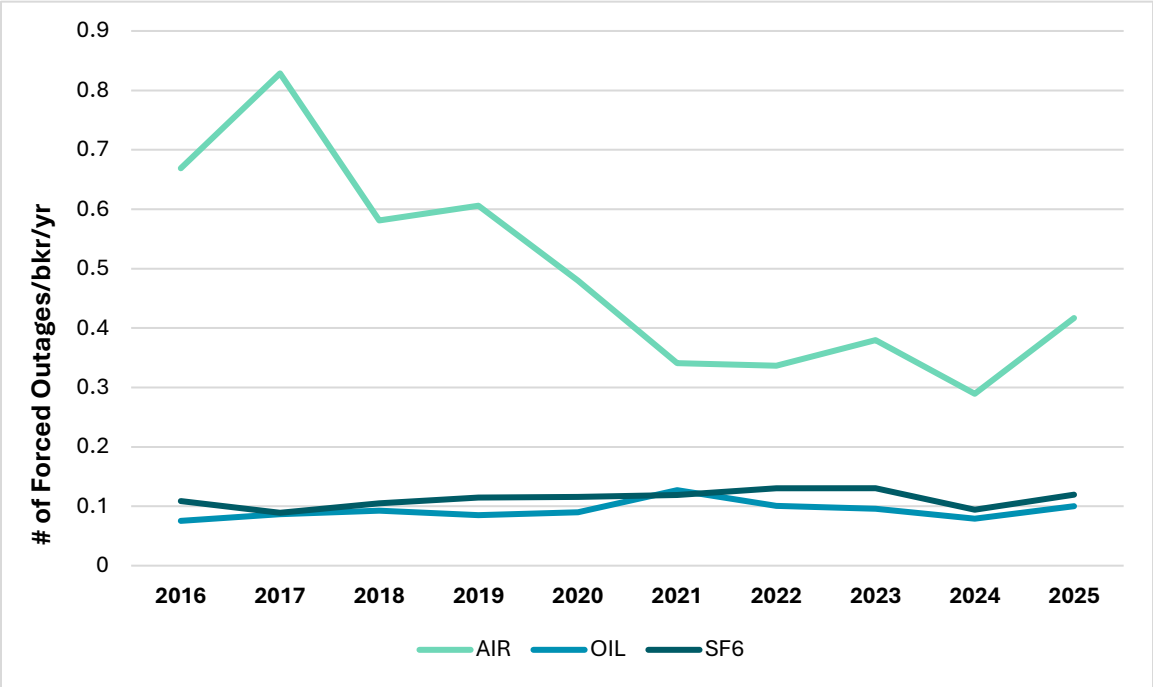

Figure 11: Circuit Breaker Forced Outages by Type

2.2.2.2.6 ASSET LIFECYCLE

Hydro One performs routine maintenance and replaces breakers that are in poor condition, are obsolete, pose safety risks, operate at or above their nameplate rating, exhibit an unacceptable level of reliability performance, or have a poor environmental footprint (e.g., leaking SF_6). Maintenance tasks facilitate the collection of diagnostic information on breakers to assess their health and need for overhaul or replacement. In addition, maintenance packages include tasks to proactively address and prevent failure modes that could lead to outages.

Hydro One's plan for the breaker fleet has been influenced by the demographic, condition, performance, vendor support, air leak, environmental factors and health and safety concerns. The plan aims to employ maintenance and replacements in order to maintain fleet performance.

2.2.2.2.6.1 INSPECTION & MAINTENANCE PRACTICES

Breaker testing and maintenance is conducted to ensure the proper mechanical operation and electrical integrity of Hydro One's breaker fleet, in order to mitigate the possibility of a breaker's failure to interrupt fault current when called upon.

Hydro One's maintenance practices are informed by manufacturers' maintenance manuals, industry technical reports and the company's maintenance experience. Table 13 summarizes the testing and maintenance activities generally applied to circuit breakers, including their frequency and purpose.

Table 13 - Circuit Breaker Testing & Maintenance Summary

Maintenance	Frequency	Description
Visual Inspection	Bi-annual	Visual and audible inspection of external and ancillary components
Diagnostic Testing	6–7 years	Function testing to assess breaker performance
X-ray	Condition Based	X-ray of internal components to check for any wear and tear along with its internal condition.
Selective Intrusive (SI) Inspection	Condition Based	Internal inspection, cleaning and replacement of worn components
Oil Analysis	1–3 years	Analysis of oil samples to assess the condition of an oil breaker's internal components
Power Factor Test	12–14 years	Condition assessment of live tank and oil breaker insulating components
Moisture Content Test	Bi-annual	Assess and manage moisture content within air blast breakers and some SF6 breakers.
Maintenance Level 1	3 years	Assess the performance and condition of pneumatic systems and comply with the Technical Standards & Safety Authority's requirements

Where feasible based on parts availability, cost and projected future reliability, breakers with leaks are repaired as part of ongoing maintenance activities. Consequently, it is important to ensure that the current carrying components are in good shape, the mechanical and control systems are operating within specification and that the insulating medium has not been compromised.

Hydro One has started using X-ray inspections on breakers that helps to visualize internal components and their condition without doing intrusive maintenance. X-ray maintenance would reduce the need for intrusive inspections and might be able to save resources,

outage times and help prioritize replacement. Hydro One has incorporated X-ray maintenance with regular maintenance.

SF_6 leak detection methods require the power equipment to be taken out of service, which can take many hours or days. Hydro One is using technologies to resolve SF_6 leaks, such as the use of SF_6 cameras, to detect leaks prior to taking breakers out of service. This may lead to reduced outage times and improved work planning.

2.2.2.2.6.2 ASSET REPLACEMENT AND REFURBISHMENT

Hydro One's breaker replacement strategy is a targeted, risk-based approach that prioritizes the renewal of breakers most likely to impact safety, reliability, or maintainability. Breakers are selected for replacement based on deteriorated condition, obsolescence, vendor support, environmental impact, system criticality, and overall safety risk.

A summary of the replacements is described in Table 14:

Table 14 - Reasons for Breaker Replacement by Breaker Type

Type	Reason for Replacement
Oil Breaker	• Condition and reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • Non-compliance with current system operating ratings • Current rating changes
Air Blast Breakers	• Significant negative impact on outage frequency • Deteriorating condition and performance • Obsolescence due to lack of vendor support and unavailability of maintenance parts • Elimination of high maintenance costs
SF_6 Breakers	• Condition and reliability concerns • First generation SF_6 breakers Obsolescence due to lack of vendor support and unavailability of maintenance parts • SF_6 emissions • Current Rating changes
GIS Breakers	• Reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • SF_6 emissions
Metalclad	• Arc flash hazards • Obsolescence due to lack of vendor support and unavailability of maintenance parts
Vacuum	• Obsolescence due to lack of vendor support and unavailability of maintenance parts

A major driver is ensuring breakers have adequate short-circuit interrupting capability. As new customer connections, system upgrades, and network reinforcements alter fault levels, Hydro One conducts project-specific short-circuit studies as part of the IESO Connection Assessment and Approval (CAA) process. Where short circuit level ratings are exceeded, breakers need to be upgraded to a higher short circuit rating, since operating beyond the nameplate rating can cause the breaker to fail.

The strategy also addresses aging and obsolete technologies that are increasingly difficult to support. This includes retiring air-blast circuit breakers, replacing older pneumatic operating mechanisms with modern designs, and managing early-vintage GIS equipment approaching obsolescence. While maintenance remains a viable short-term option for some GIS fleets, full integrated GIS replacements are expected to begin beyond the current planning period.

For fleets with limited spare part availability, Hydro One sustains operations by collecting components from decommissioned units until comprehensive replacements can be executed. Breakers that demonstrate recurring performance issues or unacceptable reliability, beyond what maintenance can reasonably resolve, are prioritized for replacement to mitigate system and safety risks.

Overall, this strategy ensures Hydro One systematically transitions high-risk and obsolete breaker fleets to modern, reliable, and supportable technologies while aligning capital investments with system needs and maximizing risk reduction.

2.2.2.3 PROTECTION SYSTEMS

2.2.2.3.1 ASSET DESCRIPTION / PURPOSE

Hydro One's protection systems are comprised of instrument transformers, relays, sensors and communication devices. The protection system is a critical element of the transmission system that detects abnormal system conditions. Upon detecting an abnormal condition, the protection systems immediately initiate the necessary station equipment to operate to isolate faulted components. If not isolated in time, a faulted

element can cause a cascading effect resulting in a major system disruption involving service interruptions, equipment damage and employee and public safety issues. Protective relays and associated systems maintain system reliability by protecting local supply as well as supply within Ontario's Bulk Electric System (BES) and mitigate the potential impact of abnormal conditions to the rest of the interconnected grid.

Protection system components also capture detailed records for post event analysis. This information assists in determining the root cause of power system events and facilitates the mitigation or elimination of the issue. The three vintages of protection systems found at Hydro One are summarized in Table 15 below.

Table 15 - Protection Fleet Description

	Type	Description	Production Status	Vendor Support
	Electromechanical Systems	Electromechanical systems utilize the principles of electromagnetic induction to convert electrical energy to mechanical movement in order to detect faults.	Obsolete	No
	Solid State Systems	Solid State systems rely on integrated circuit technology to detect fault conditions.	Obsolete	No
	Microprocessor Systems (1st Generation)	Microprocessor based protection systems, also known as Intelligent Electronic Devices (IEDs) are the newest technology. These relays utilize microprocessors to offer multiple protection functions and additional features. These features enable post-fault technical analyses not available in legacy technologies.	Obsolete	No
	Microprocessor Systems (Current)		Active	Yes

2.2.2.3.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.2.3.3 ASSET DEMOGRAPHICS

Hydro One currently has 12,748 protection systems in-service. In contrast to other major power system assets like transformers and conductors (which are replaced based on the condition of the equipment), the ESL of protection devices plays an important role in the assessment for replacements of protection relays. This is because assessment for physical breakdown or loss of strength over time is not feasible or relevant given the make-up of these electronic or solid-state devices. As such, to prevent the potentially significant reliability and safety impact of a sudden failure, ESL is necessarily a key trigger for further evaluation to confirm replacement needs.

As outlined in Table 16 below, approximately 26.1%[5] of the total Hydro One protection system population is operating beyond ESL. Such devices are subject to an elevated risk of failure, while also having very limited or no support from vendors in terms of replacement units, spare parts, and engineering and firmware support. As such, reactive repairs may involve extended durations as re-engineering and construction work will be required to install new devices based on different technology. These risks could lead to protracted outages for customers.

Table 16 - Hydro One – Protection Systems Demographics

Type	Quantity	Avg Age (Years)	ESL (Years)	Beyond ESL	
				Quantity	% of Type
Solid State	1,335	40.8	25	1,207	90.4%
Electromechanical	2,349	44.3	45	1,263	53.8%
Microprocessor	9,064	11.5	20	859	9.5%
Total	**12,748**			**3,329**	**26.1%**

As outlined in Table 17 below, approximately 4.4%[6] of the total HOSSM protection system population is operating beyond ESL.

[5] 3,329 out of the total Hydro One protection system population of 12,748
[6] 10 out of the total HOSSM protection system population of 229

Table 17 - HOSSM – Protection Systems Demographics

Type	Quantity	Avg Age (Years)	ESL (Years)	Beyond ESL	
				Quantity	% of Type
Solid State	0	-	25	-	-
Electro-mechanical	26	23.4	45	0	0.0%
Microprocessor	203	12.4	20	10	4.9%
Total	**229**			**10**	**4.4%**

2.2.2.3.4 ASSET CONDITION

As noted above, Hydro One uses the ESL of relays as a trigger for protection replacement assessment to investigate a relay, including the risk of its potential failure with respect to reliability and safety, spare availability and availability of vendor support.

It is not feasible to assess the physical condition of this class of asset so other factors are used as triggers for replacement decision, including increased failure rates related to specific models or families of devices, limited or non-existent manufacturer support (i.e., provision of spare parts and repair services), obsolescence and the inability to comply with current reliability standards. With respect to the priority of protection replacements, Hydro One's strategy is to target protections with a high likelihood of failure.

2.2.2.3.5 ASSET PERFORMANCE

Protection system misoperations are the single most important indicator of the protection system's overall performance. Hydro One tracks the performance of the protection system by analyzing every protection system operation to determine if it operated as expected. A subset of this data that relates to devices that form part of Hydro One's BES (approximately 43% of all Hydro One assets) is reported to the NERC and NPCC as part of the company's compliance obligations. Based on NERC data, Hydro One is able to track its protection system performance compared to other utilities in North America. As shown in Figure 12, for the past five years, Hydro One's BES protection system misoperation rate performed cumulatively better than the rate experienced by the NPCC region. As such, the proposed protection replacement strategy is vital to maintaining this level of performance.

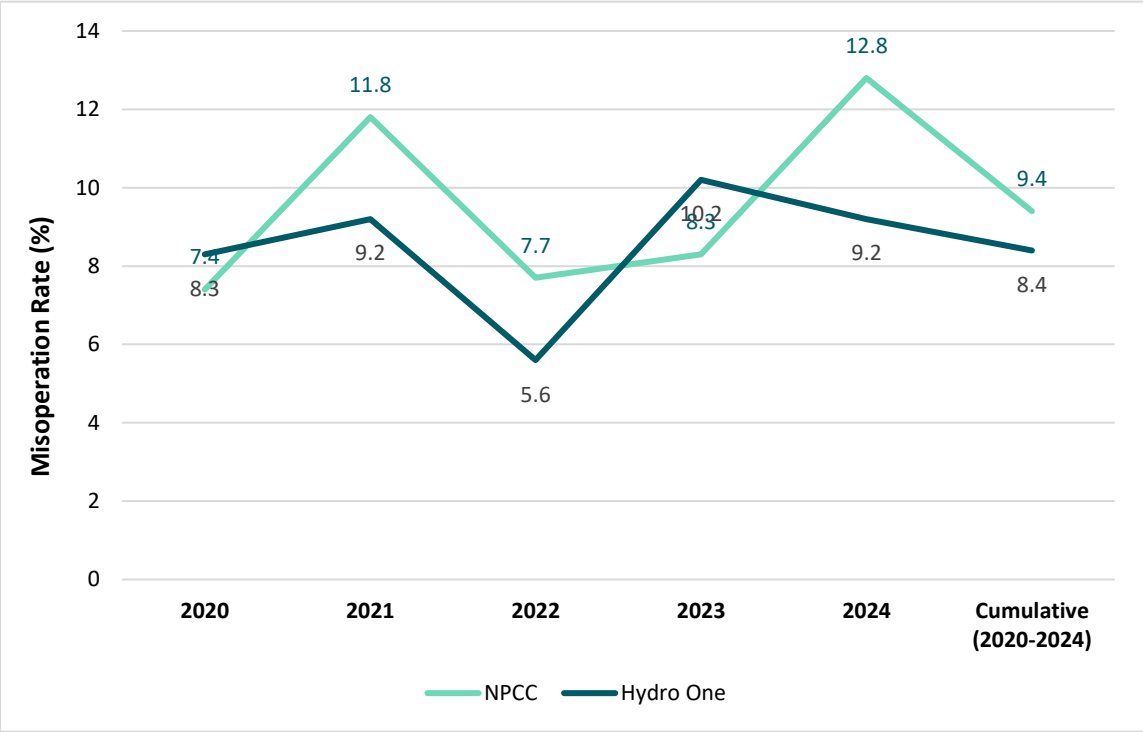

Figure 12: Hydro One and HOSSM Protection Systems Misoperation Rate[7]

2.2.2.3.6 ASSET LIFECYCLE

2.2.2.3.6.1 INSPECTION & MAINTENANCE PRACTICES

Hydro One aims to maintain system reliability by ensuring the correct protective operation is initiated to isolate a faulted asset from the system. To this end, Hydro One performs both preventive and corrective maintenance to ensure acceptable performance and remediate deficiencies whenever technically and economically feasible. The type and frequency of maintenance often depend on the type of protection system, the type of power system asset being protected, and the criticality of that asset.

For BES elements, a number of NERC standards govern the protection system maintenance program, including:

[7] NPCC figures include misoperation data from the State of New York and the six New England States as well as the Canadian provinces of Ontario, Québec New Brunswick and Nova Scotia. NERC data combines data from all of North America.

- PRC-004 Protection System Misoperation Identification and Correction – The purpose of this standard is to identify and correct the causes of protection system misoperations for BES elements.
- PRC-005 Transmission and Generation Protection System Maintenance and Testing – The purpose of this standard is to document and implement programs for the maintenance of all protection systems affecting the reliability of the BES so that they are kept in proper working order.
- PRC-012 Remedial Action Schemes – The purpose of this standard is to ensure that Remedial Action Schemes do not introduce unintentional or unacceptable reliability risks to the BES.

For Bulk Power System (BPS) elements, a subset of BES, a number of NPCC standards govern the protection system maintenance program, including:

- NPCC Regional Reliability Reference Directory # 4 – System Protection Criteria – This document provides the design criteria for BPS protection within the service territories of NPCC member organizations.
- NPCC Regional Reliability Reference Directory # 7 – Special Protection Systems – This document provides the basic criteria for Special Protection Systems to ensure the reliable operations of the bulk power system.
- NPCC Regional Reliability Reference Directory # 8 – System Restoration – This document sets out the requirements for performing bulk power system restoration.

Preventive Maintenance

Preventive maintenance involves time-based routine testing or re-verification of protection systems. Protection systems spend most of their service life in a dormant state, yet must be relied upon to perform flawlessly during a fault or other abnormal system conditions. Routine testing is the only means to maintain a high degree of certainty that the system will operate correctly when called upon.

For protection systems that are part of the BES, the testing frequency is governed by applicable mandatory NERC standards.[8] Hydro One has adopted shorter maintenance cycles than what NERC prescribes. This was done to mitigate the risk of non-compliance in case maintenance required pursuant to NERC or NPCC prescribed cycles cannot be performed on time due to operational constraints or other reasons.

For the remaining non-BES protection systems, Hydro One follows internal policies in accordance with good utility practice. In the past, Hydro One employed similar maintenance planning criteria for all protection systems, regardless of whether their maintenance was required by the applicable NERC standards. Hydro One began adopting longer maintenance intervals for non-BES protection systems, either due to advancements in technology (e.g. self-monitoring capabilities of micro-processor relays) or outage alignment or limited funding for maintenance.

Table 18 below summarizes the preventive maintenance schedules for protection systems.

[8] See: PRC-005- Transmission and Generation Protection System Maintenance and Testing and PRC-012 Remedial Action Schemes

Table 18 - Protection Systems Preventive Maintenance Intervals

Type	Regulatory Maintenance (Required by NERC or NPCC)[9]		Non-Regulatory Maintenance (Years)[10]
	Hydro One Maintenance Cycle (Years)	Maximum Allowed Cycle by NERC (Years)	
Microprocessor Relays (non-feeder)	10	12	10
Electromechanical and solid state (non-feeder)	5	6	10
Microprocessor Relays (feeder) [11]	N/A	N/A	10
Electromechanical and solid state (feeder)	N/A	N/A	10
Breaker Trip Coil Tests (BTCT) [12]	5	6	N/A
Zone Test Tripping (ZTT)	10	12	10
ST3 - NPCC Directory 8	4	60 months	N/A
Property Visual Inspection (PVI)[13]	N/A	N/A	5 or 10
Special Protection Transfer Tripping (SPTT)	5 or 10	6 or 12	N/A

Corrective Maintenance

Given the unplanned nature of failures or defects, there is variability as to the number and severity of corrective maintenance activities (categorized as either emergency or planned work) performed every year:

i. Emergency corrective maintenance is driven by urgent unforeseen problems, including trouble calls, defects found during discovery work, and protection equipment failures. This emergency work is given priority for correction within 30 days.

ii. Planned corrective maintenance proactively addresses the non-urgent, unforeseen problems and protection equipment failures, allowing longer time frames for corrective work (>30 days).

[9] Regulatory maintenance is performed on a subset of Hydro One protection system assets (approximately 41%) that are part of the BES system.
[10] Timed maintenance covers maintenance of protections assets not included in BES system.
[11] Maintenance of Hydro One's feeder protections is not required by NERC standards.
[12] Tests performed on BES assets only.
[13] There are no regulatory requirements for visual inspections to be performed.

Support Processes and Systems

Hydro One maintains a set of support processes and systems for protection equipment that are in place to manage change control of the settings and configuration of protection and control systems, keep records of events, as well as manage the inventory and the re-seal schedule for revenue meters. Additionally, any protection operation requires field staff to validate and gather event records required for Natural Occurring Event Analysis (NOEA) investigations, which are mandated by NERC standard PRC-004 to determine whether the protection system performed as designed. When corrective maintenance involves a problem that exists in other locations, a program may be created to remedy the deficiencies in the identified locations.

2.2.2.3.6.2 ASSET REPLACEMENT AND REFURBISHMENT

Hydro One's strategy for protection systems is focused on replacing systems that have a high likelihood of causing delivery point interruption and impacting the reliability of BES with modern integrated systems. Given Hydro One's protection system fleet's demographics, performance and risks associated with equipment failures, a continued focus on replacement efforts is required to maintain system reliability performance. In addition, because of the shorter ESL of new technologies, the rate of relay replacements will increase in order to maintain Hydro One's ability to manage future relay failures and to manage replacement of aged and obsolete assets to keep risks at an acceptable level. As explained above, ESL and other factors are used as a trigger to identify high risk assets which undergo further assessment to identify replacement candidates. Other factors driving protection system replacements are summarized below:

- Safety – Protection system failure to operate can potentially expose workers and the public to the risk of electrocution, which can result in significant injuries or fatalities. Proactive replacements are required to mitigate this risk.
- Regulatory Compliance – Hydro One's protection system must comply with all applicable NERC and NPCC standards. Protection system upgrades are often needed to comply with new or updated standard requirements.
- Historical Performance – Failure rates over the historical period for a particular relay model are used to help identify fleet deterioration of that specific relay model.

- System Reliability Risk – The impact of protection on power system reliability depends on its location in the power system, the criticality of the protected element, protective function and redundancy. Power system reliability risk due to potential protection failure or misoperation is being factored in the replacement decision process.
- Functional Requirements – The requirements for protection system functionality may change due to power system changes (e.g., system stability requirements) or changes to other components of the integrated protection and automation system, which may lead to incompatibility of the existing protection hardware with the associated devices.
- Obsolescence – Many protection system components are no longer available, limiting the availability of spare parts and support; which can adversely impact outage planning and overall system reliability. This is a significant factor for electromechanical and solid-state systems as they are no longer supported by relay vendors which are focusing their efforts on microprocessor-based relays.
- Innovation – New microprocessor-based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage.

As microprocessor-based relays are now the only viable protection technology, replacement rates will increase due to their significantly shorter expected service life (ESL). While obsolete electromechanical relays typically operate for 40–60 years, modern microprocessor relays have an ESL of roughly 20 years, with failure rates rising beyond that point. In addition, certain relay models have experienced systemic failures, driving higher corrective maintenance and, in many cases, large-scale replacements.

A major sustainment challenge is the steadily shrinking period of vendor support for modern relays, which has substantial impacts on lifecycle management. Support timelines continue to decline due to manufacturers' parts sourcing constraints, rapid technological turnover, and ongoing feature enhancements driven by competitiveness. This challenge

is further compounded by evolving network connection standards that often prevent like-for-like replacements.

Some large North American utilities are considering or adopting a shorter ESL for microprocessor relays with typical values ranging from 15 to 20 years in response to original manufacturers' statements of product support, ESL of device components, and the average lifespans for similar devices adopted by peer utilities. Hydro One is proactively managing this issue by working with suppliers to gain extended support for their products in order to maintain the ESL for microprocessors at 20 years.

Notwithstanding the increased costs for compliance obligations, replacing older style relays with modern protections can partially offset OM&A costs. Modern protections include self-monitoring features which alert control room staff when they fail. The control room can then take appropriate action and dispatch crews to perform repairs. Older style relays, such as electromechanical relays, do not contain these features. Their malfunction can only be detected during routine maintenance or when they fail to perform as designed during system events. Because of this difference, NERC standard PRC-005 allows for an increased period between required testing of modern relays. For example, the PRC-005 maintenance cycle for electromechanical relays (no self-monitoring features) is 6 years; whereas modern microprocessor relays can be maintained once every 12 years.

In addition to traditional station protection devices, there is a small subset of protection and control devices associated with Static VAR Compensators (SVCs) and Series Capacitors (SCs). These P&C devices are customized per installation, specific to the equipment vendor. A similar replacement strategy applies to these P&C devices, the ESL is the primary trigger for replacement, prioritization given to stations with NERC CIP impact.

2.2.2.4 AUTOMATION SYSTEMS

2.2.2.4.1 ASSET DESCRIPTION / PURPOSE

Automation assets are highly complex electronic systems which integrate substation and switchyard devices. These systems enable the monitoring and control of power system assets and facilities at all times to achieve safe, reliable and efficient operation of the Ontario transmission grid.

Automation systems provide several critical capabilities to support Hydro One's power system monitoring and control, including:

- Supervisory Control and Data Acquisition (SCADA) – local and remote real-time monitoring, control and troubleshooting functionality for Hydro One field staff, control center operators and the IESO in accordance with Market Rules;
- Collection, processing, and archival of non-operational data for post-event analysis and to support the asset management decision-making processes;
- Enabling cybersecurity functionalities such as system event monitoring, authentication, authorization, logging and accounting; and
- Supporting the fulfillment of regulatory obligations.

Hydro One's automation fleet consists of a variety of devices to provide these functionalities. These devices are listed in Table 19.

Table 19 - Automation Fleet Description

Type	Description
Remote Terminal Unit (RTU)	SCADA device that interfaces with primary yard equipment to provide control and monitoring functions locally and remotely to the control center.
Programmable Synchrocheck Relay (PSR)	The PSR is a device that checks the voltages on both sides of a circuit breakers for synchronization prior to operation of the circuit breaker.
Gateways	The gateway is a multifunctional device and key component in the Hydro One SCADA network. It is a protocol translator, data concentrator for station devices, and communicates station SCADA to the control centers. It can be equipped with a Human Machine Interface (HMI) to provide local control and monitoring for station equipment.
Hub Site Gateways	A gateway device as described above, that is specifically used at hub site locations to consolidate SCADA data from multiple stations in a region, providing protocol translation and communicating this data to the control centers.
Local Control Computer (LCC)	Station computer that provides local interface for control and monitoring of primary yard equipment.
Local Maintenance Computer (LMC)	Station computer that provides an interface to station protection and control (P&C) equipment for maintenance and commissioning purposes.
Routers and Switches	Network devices that connect station equipment to a Local Area Network (LAN) and to the Wide Area Network (WAN).
Disturbance Monitoring Equipment (DME)	Power system recorders which log data used for post-fault analysis and disturbance analysis. They consist of three separate devices: the Sequence of Event Recorder (SER), the Digital Fault Recorder (DFR) and the Dynamic Disturbance Recorder (DDR). SERs monitors the status of power system equipment and operation of protection and tele-protection systems. It records state changes and the corresponding time. DFRs monitor and record instantaneous analog and digital signals for post-fault analysis of protection system operation, it captures and stores transient fault data when triggered by conditions detected on the power system, such as waveform signals of currents and voltages. The record lengths on the DFR are usually from milliseconds to seconds. DDRs record data that portrays the overall system condition during dynamic events that may last for many seconds, such as low frequency oscillations. The record lengths on the DDR are usually from seconds to minutes.
Phasor Measurement Unit (PMU)	Device used to collect time synchronized, phase and magnitude telemetry of power system elements. Sychrophasor data acquired from several key points of a wide area can be used to monitoring of the health of the power grid.

2.2.2.4.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.2.4.3 ASSET DEMOGRAPHICS

There are over 9,200 automation devices in service consisting of different technological vintages. Table 20 describes the different vintage types along with production status, available vendor support and expected service life.

Table 20 - Automation Type Description

Type	Description	Production Status	Vendor Support	ESL (Years)
Legacy	Copper based technology with a high volume of physical wiring, pre-LAN based communication.	Obsolete	No	20
Modern (1st Gen)	Early IP-based devices; no longer manufactured	Obsolete	No	15
Modern (current)	Current Hydro One standard devices built on contemporary IP-based communication technology	Active	Yes	15

Legacy or first-generation modern devices are no longer supported by vendors, do not receive vendor software updates, and cannot be supplied with replacement units or individual components. Hydro One's ability to support these obsolete devices depends on the on-hand supply of spares, and as these spares diminish, so does Hydro One's ability to maintain the devices and perform like-for-like replacements. Of the approximately 9,200 devices in the automation fleet, 4% are legacy, 60% are first-generation and 36% are current modern, vendor-supported devices.

Hydro One uses the ESL of the different automation device vintages as a trigger for replacement assessments, in contrast to major power system assets like transformers and conductors, which are replaced based on equipment condition. This is because assessment for physical breakdown or loss of strength over time is not feasible or relevant given the makeup of these electronic devices. As such, to prevent the potentially significant reliability and safety impact of a sudden failure, ESL is a key trigger for further evaluation to confirm replacement needs. The ESL for legacy copper-based automation

devices is 20 years, and the ESL for modern IP-based devices is 15 years, based on generally accepted industry practices and Hydro One's experience.

There are approximately 1,600 RTUs in service:

- 8% are legacy.
- 76% are 1st generation.
- 16% are modern and vendor supported.

Alongside the RTU is the PSR, an accompanying unit that is coupled with an RTU to check the voltage on both sides of a circuit breaker for synchronization prior to allowing the RTU to close the circuit breaker. There are approximately 125 PSRs in service and they are all considered legacy.

Gateway devices have a total installed base of approximately 1,180 devices.

- 24% are 1st generation.
- 76% are modern and vendor supported.

Hub site gateways are gateways devices used specifically for regional consolidation of station data. They are being phased out as Hydro One connects stations directly to control centers. There are approximately 168 hub site gateways installed.

- 82% are 1st generation.
- 18% are modern and vendor supported.

The LCCs and LMCs are legacy station computers that operate on obsolete Windows platforms and have been functionally superseded by other station devices. As a result, these systems are now considered obsolete, yet approximately 95 LCCs and 32 LMCs remain in service.

PMU devices collect synchrophasor data, high resolution data that when gathered across a wide area can monitor the health and stability of the power grid. Synchrophasor data is required by IESO Market Rules.

- 11 PMUs are 1st generation.
- 14 PMUs are modern and vendor supported.

2.2.2.4.4 ASSET CONDITION

Automation devices' internal components degrade as a function of time, which can alter their performance. Because of the nature of electronic devices, condition cannot be directly measured. Instead, Hydro One uses the ESL of assets as a trigger for replacement assessment, prioritizing devices with a high likelihood of failure. Legacy vintage devices are prioritized, as are first generation devices with a high rate of failure or deficiencies based on defect reports, trouble calls, and potential need identifications.

2.2.2.4.5 ASSET PERFORMANCE

Automation system performance is primarily determined based on automation asset defect reports. Table 21 below shows the number of automation equipment defect reports over the past six years.

Table 21 - Automation Defect Reports

Year	RTU	PSR	Gateway	LMC/LCC	Router	Switches
2020	673	36	86	80	35	74
2021	672	25	140	60	45	72
2022	792	6	155	65	22	48
2023	751	21	179	87	30	85
2024	773	28	178	56	25	62
2025	544	22	96	59	40	54
Total	**4,205**	**138**	**834**	**407**	**197**	**395**

From the data presented above, the highest number of deficiencies is with the RTU. This is due to the RTU having the highest quantity of units, at almost 1,600 devices, as well as being the most complex of the automation fleet, with the highest number of associated components. The gateway deficiencies are next highest which is also reflective of the overall quantity of units, approximately 1,180 devices. LMC/LCC are devices that will ultimately be removed from the system and it is expected for those numbers to reduce to zero as removals are completed.

2.2.2.4.6 ASSET LIFECYCLE

2.2.2.4.6.1 INSPECTION & MAINTENANCE PRACTICES

There is no regularly scheduled maintenance on automation assets other than planned replacement. Corrective maintenance work for automation assets is reactive in nature and involves prioritizing and remedying issues identified through trouble calls and defect reports that occur during everyday operations.

2.2.2.4.6.2 ASSET REPLACEMENT AND REFURBISHMENT

To ensure reliable operation of the transmission system, Hydro One plans to manage the automation fleet with planned replacement of all ESL equipment with a focus on legacy devices, as these devices are the oldest in the Hydro One Automation fleet and use outdated technology. Also prioritized will be 1st generation modern devices, that have a high rate of failure and deficiency reporting.

<u>RTU</u>

RTUs are the most complex devices of the Automation fleet with several sub components required to handle physical wiring. Legacy RTUs are copper based devices; they have a large quantity of physically wired inputs and outputs and lack network connection ports. Hydro One is prioritizing the replacement of legacy RTUs as well as 1st generation RTUs with a high rate of failure or reported deficiencies. The failure of a legacy RTU can cause a significant outage, they are so outdated that like-for-like replacements are not possible, and installing a new modern device will take additional time to be installed and commissioned.

<u>PSRs</u>

In some installations, a PSR unit will accompany an RTU providing a specific sychrocheck function for the RTU, checking the voltage on both sides of a circuit breaker for synchronization before the RTU operates the circuit breaker. As RTUs are targeted for replacement, Hydro One is replacing the accompanying PSR at the same time.

Gateways

Gateways are multi-functional devices that are a key components of the Hydro One SCADA network. They function as a protocol translators, data concentrators andlocal control interfaces and communicate station SCADA to the control centres. Failure of these devices is considered high risk. Hydro One is replacing first generation gateways with modern, vendor supported devices.

Station Computers

Station computers, namely the LMC and LCC, are no longer required because the functionality provided by these computers has been merged with other station devices. Hydro One is decommissioning all LMC and LCC units.

Hub Site Gateways

Hub-site gateways were required under the old network architecture, where data from several stations in a region were consolidated at a hub site before being forwarded to the control centre. This was mainly to address the telecommunications and control-device limitations at the time. Station data can now be communicated directly to Hydro One control centres using the new architecture configuration called Direct SCADA. As stations are moved to this new network configuration, Hydro One is decommissioning hub-site gateways.

PMUs

PMUs collect synchrophasor data, which are high-resolution, time-synchronized data that, when gathered at several points across the system, can be used to monitor the health of the power grid. As of December 2024, synchrophasor data are required by IESO Market Rules. Hydro One is replacing all first-generation PMU devices and installing new modern devices at all required stations to fulfil compliance obligations.

2.2.2.5 POWER SYSTEM TELECOM

2.2.2.5.1 ASSET DESCRIPTION / PURPOSE

Power System Telecom includes communication systems, infrastructure, and leased facilities that enable the essential protection, control, monitoring and operation of the transmission system in Ontario.

Power System Telecom Services (PSTS) are used for the following applications:

- Station-to-station telecommunications used by protection systems;
- Telecommunications between the control center, hub site and transmission stations for remote monitoring and control of equipment; and
- Telecommunications with customer owned protection and control equipment.

Power System Telecom assets are categorized as part of the following systems or asset types:

- Synchronous Optical Networking (SONET) transport network;
- Fibre optic cable infrastructure;
- Power Line Carrier (PLC) systems;
- Teleprotection terminal devices;
- High Voltage Protection (HVP) systems;
- Microwave radio systems; and
- Provincial Mobile Radio System (PMRS).

In addition to the above telecom assets, Hydro One also:

- Uses carrier-based leased services to provide PSTS. These include communication channels over copper and fibre facilities, as well as Virtual Private Networking (VPN) services from telecommunication providers;
- Engages Acronym Solutions Inc., an affiliate of Hydro One, to provide operational services for Hydro One's telecommunication network, including coordinated network management, vendor management, alarm based monitoring and system analysis services;

- Leases approximately 1,700 km of fibre acquired under Indefeasible Right of Use (IRU); and
- Leases sites and/or space from third parties for the provincial mobile radio system.

SONET Transport Network

Hydro One's core telecommunication network is based on SONET transport technology and is primarily used for protection systems and communication between SCADA systems, the control centre, hub sites and transmission stations. Additionally, it is used for communicating non-operational data, business data, voice and security information and as backhaul for the provincial mobile radio system. The network topology connects stations in rings to provide redundant communication links that can extend hundreds of kilometres across the province.

The SONET network uses multiplexer equipment composed of two vintages: (i) the first generation, initially deployed between 1998 and 2007, and (ii) the second generation, deployed from 2004 onwards. In addition to the multiplexer equipment, the SONET network includes microwave radios, optical amplifiers and 48 VDC backup power supplies for communications equipment. Certain segments of the SONET network consist of microwave links rather than fibre-connected paths. These obsolete microwave links have created capacity and bandwidth limitations on a typical SONET ring topology.

Fibre Optic Cable Infrastructure

Hydro One uses fibre-optic cable infrastructure, including Hydro One-owned and operated aerial fibre-optic cables and fibre strands acquired through Indefeasible Right of Use (IRU), to support Hydro One's communications network. Aerial fibre-optic cable primarily comprises: (i) Optical Ground Wire (OPGW) technology, with strands of fibre embedded inside the shield wire mounted on top of high-voltage transmission structures; and (ii) All-Dielectric Self-Supporting (ADSS) fibre cable attached to towers or poles, typically below the phase conductors.

Power Line Carrier Systems

PLC systems are used by Hydro One to provide an alternative means of dependable communications between stations. These systems use high-voltage power lines as the communication medium. The primary components include radios, line traps, matching units and coupling capacitors.

Teleprotection Terminal Devices

As part of the standalone or integrated teleprotection systems, teleprotection terminal devices provide an interface between the protection relays and the communication network, SONET or carrier-based leased services. Based on the communication medium used, these devices are classified as:

- T1 access multiplexers that provide digital teleprotection over the SONET network; and
- Tone devices that cater to teleprotection applications over leased facilities.

High Voltage Protection (HVP) Systems

Hydro One leases telephone communication circuits from third-party telecommunication service providers that may be subjected to a very high voltage rise when a fault occurs on the power system, potentially exposing personnel and equipment to hazardous high voltages. For this reason, special HVP systems are required for all of Hydro One's leased telecommunication circuits.

The primary component of the HVP system is the High-Voltage Interface (HVI) equipment that provides the required electrical isolation and safe limits of any difference in potential. Hydro One's inventory of HVI equipment includes neutralizing transformers, isolating transformers and optical isolators.

Microwave Radio Systems

Hydro One's licensed microwave radio systems support the SONET network and last mile point-to-point telecommunication applications. The microwave radio systems are supported by infrastructure that includes marked radio communication towers to satisfy aviation safety requirements, microwave buildings, and backup power supplies. Hydro

One's communication towers are also utilized by the provincial mobile radio system and for third party attachments.

Provincial Mobile Radio System

Hydro One owns and operates a private radio system that is used for two-way voice communication between control centers and field crews during restoration efforts, emergency operations and day-to-day construction and maintenance work. The mobile radio system provides coverage that exceeds the limited cellular coverage in remote areas, and is often the only means of communication in these areas. The system includes radio base stations and radios equipped in Hydro One's fleet.

2.2.2.5.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

Hydro One currently owns approximately 4,287 microprocessor based communication devices, 987 ancillary communication equipment, 149 radio communication towers, 143 mobile radio base stations and approximately 2,560 km of fibre optic cable that, combined with 1,700 km of third-party fibre acquired through IRU, these assets make up the communication systems and infrastructure used to provide PSTS.

Hydro One takes into account asset age, manufacturer recommendations and historical asset retirement records in order to determine ESL. The ESL for most microprocessor based equipment is 15-20 years. Table 22 shows the ESL in years for each asset type. Table 23 provides the corresponding demographic profile of HOSSM's Power System Telecom assets, including the quantity, ESL and number of assets beyond ESL for each asset type.

Table 22 - Hydro One – Power System Telecom Asset Demographics

Telecom System/Asset Class	Type	Quantity	ESL (Years)	Beyond ESL
SONET Communication Network	Multiplexers	276	15	221
	Digital Radios	16	15	16
	Optical Amplifiers	32	15	28
	48 VDC Batteries	239	10 - 20	57
	48 VDC Chargers	239	20	43
	OPGW	2,500 km	40	0
	ADSS	60 km	15	60 km
Power Line Carrier Systems	PLC Radios	423	20	181
Teleprotection Terminal Devices	T1 Multiplexers & Tone Devices	3215	20	972
Microwave Radio Systems	T1 Radios/ Sub-T1	325	15	67
Radio Communication Towers	Hydro One Owned	149	80	0
	Leased space	72	N/A	N/A
High-Voltage Protection System	Neutralizing/Isolation Transformers/ Opto-Isolators	491	30 - 50	241
Provincial Mobile Radio System	Radio Base Stations Equipment	143	20	143

Table 23 - HOSSM – Power System Telecom Asset Demographics

Telecom System/Asset Class	Type	Quantity	ESL (Years)	Beyond ESL
SONET Communication Network	Multiplexers	16	15	12
	OPGW	200 km	40	0
Power Line Carrier Systems	PLC Radios	5	20	5
Teleprotection Terminal Devices	T1 Multiplexers & Tone Devices	25	20	13
Radio Communication Towers	Hydro One Owned	5	80	0
	Leased space	2	N/A	N/A
High-Voltage Protection System	Neutralizing/Isolation Transformers/Opto-Isolators	8	30-50	7
Provincial Mobile Radio System	Radio Base Stations Equipment	5	20	5

Hydro One uses asset ESL information as a screening factor for asset replacement assessment, along with hardware obsolescence or level of vendor support, spare equipment availability, performance or failure rates and equipment conditions from preventive maintenance findings. Given the nature of these assets, it is not feasible to assess their actual physical condition. As such, field deficiency reports, trouble calls, and failure incidents provide an indication of the overall condition of Power System Telecom assets.

SONET Transport Network

Large segments of the first vintage of multiplexer equipment are currently beyond ESL and face technological obsolescence as vendors withdraw support. As such, it has become challenging to repair defective components, and spare parts are increasingly difficult to find. The majority of Hydro One's SONET equipment failures continue to be associated with the first vintage of multiplexer equipment (Vintage A MUX), as shown in Figure 13, which has experienced increasing failure rates. These failures have resulted in multiple PSTS being unavailable until corrective repairs were completed. HOSSM operates a separate small-scale SONET network comprised of Vintage B MUX equipment and has recorded one equipment failure over the last 5 years.

Loss of communication channels from SONET equipment failures can result in the removal of power system equipment from service or power-flow constraints on the transmission system because protection systems dependent on communications cannot protect the equipment and the Ontario Grid Control Centre loses visibility of the equipment's status. In turn, this can negatively affect communications availability in support of NERC and NPCC protection-system requirements and the reliability of the transmission system and potentially expose customers to a less reliable configuration because of the state of the SONET network.

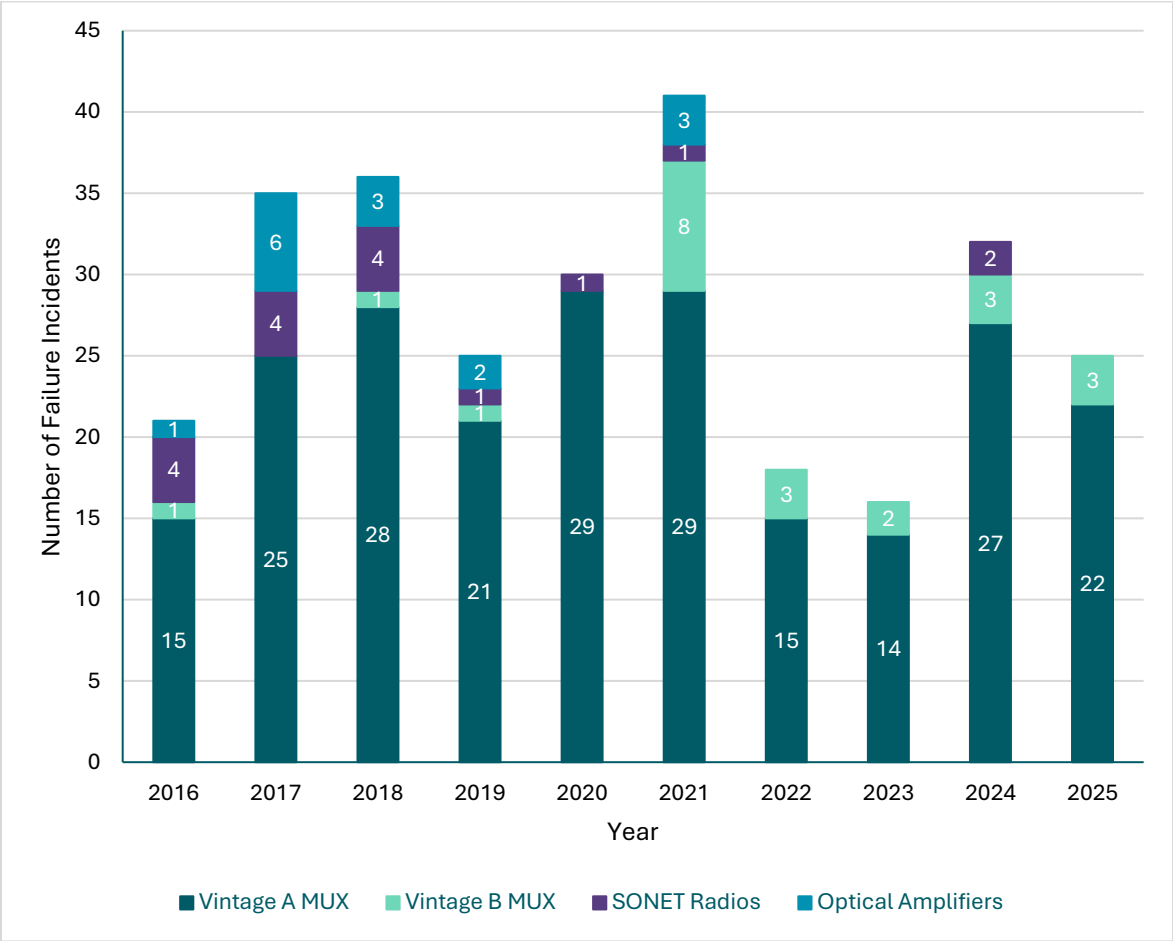

Figure 13: SONET Equipment Failure Incidents

Hydro One has experienced degraded performance in recent years from many microwave radio systems used in the SONET communication network, which are currently being phased out. Failures of these systems have rendered multiple PSTS unavailable until repairs were completed. Due to the age and performance of these systems and the significant risk they pose to reliable transmission-system operation, preventive maintenance continues at a higher frequency than regulatory maintenance requirements until the systems can be replaced.

In addition, 48 VDC batteries are critical to the reliable operation of Hydro One's Power System Telecom assets, and their condition and performance degrade significantly with age. Hydro One aims to minimize the number of batteries that exceed ESL and continues

to monitor their condition. Hydro One prioritizes batteries that exceed ESL for replacement, with consideration of their historical performance.

Fibre Optic Cable Infrastructure

The ESL of fibre-optic cable is based on the cable type. The manufacturers' recommended ESL is 40 years for OPGW and 25 years for ADSS; however, Hydro One has lowered the ESL for ADSS to 15 years. Historical performance shows that mechanical stress on ADSS fibre-cable installations has prematurely reduced cable life. When Hydro One first installed ADSS cables, limited research was available to fully understand their design principles, maintenance requirements and operational risks. Since then, historical performance has shown that a combination of these factors has contributed to unusual mechanical stresses and some early failures, resulting in the ESL for ADSS cable being lowered to 15 years.

Regarding OPGW reliability, third-party-provided leased fibre routes have historically performed significantly worse than Hydro One-owned OPGW sections. Leased fibre routes tend to be installed on public road allowances, wood poles or railway corridors, making them more prone to frequent and sometimes prolonged outages due to road accidents or train derailments. The worst-performing SONET ring in the Hydro One network is Ring 7, located north of Essa in northern and northeastern Ontario, which was originally built using 100% third-party-provided fibre. In 2022, Ring 7 was changed to include a small portion of Hydro One-owned OPGW fibre. Figure 14 shows the historical occurrences of fibre breaks for each SONET ring between 2016 and 2025.

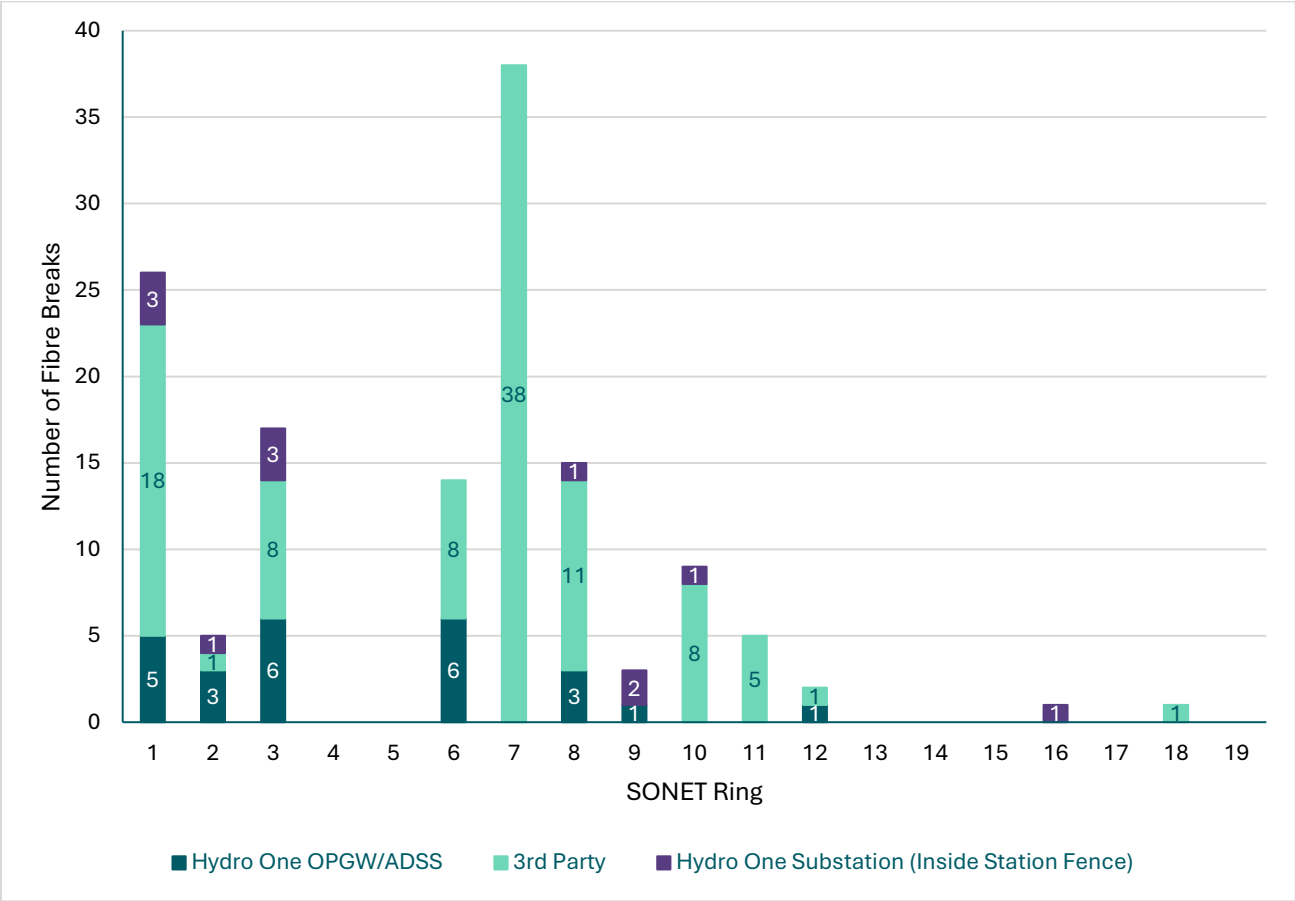

Figure 14: Fibre Breaks by SONET Ring (2016-2025)

Power Line Carrier Systems

PLC radios are microprocessor-based devices and have an ESL of 20 years. Outdoor equipment such as line-traps, tuners and coupling capacitors have an ESL of 40 years, similar to that of other station yard equipment such as power instrument transformers or HV/LV switches.

Approximately 43% of Hydro One's fleet of PLC radios have exceeded their ESL, are no longer supported by the manufacturer and are considered obsolete. As shown in Figure 15, these vintages of PLC radios have been contributing to the majority of the defects that Hydro One has experienced on its PLC systems.

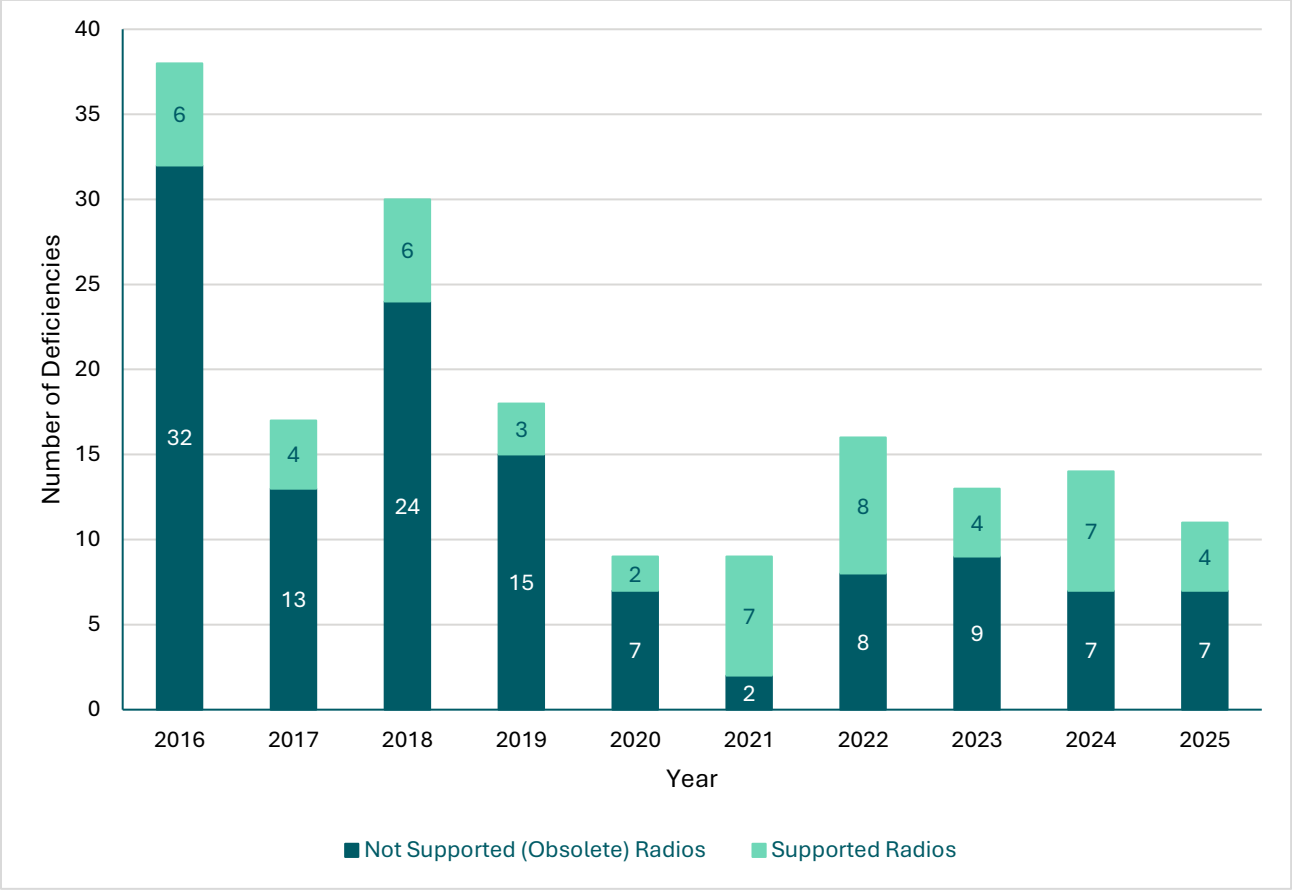

Figure 15: PLC Radio Deficiencies

Failures of outdoor passive PLC equipment are significantly less frequent than failures of indoor PLC radios. Since 2016, there have been nine failures or defects associated with outdoor PLC equipment, compared with an average of 18 defects per year for indoor PLC radios.

Teleprotection Terminal Devices

Based on the industry-accepted ESL for microprocessor-based devices, the ESL of these communication devices is estimated at 20 years. Approximately 52% of T1 access-multiplexer deployments were installed as part of the analog microwave replacement program that occurred between 1998 and 2007. The majority of these devices have reached ESL. Inventory reports also show that approximately 16% of deployed tone devices have exceeded their ESL.

High Voltage Protection Systems

Neutralizing transformers (NTs) have been deployed in Hydro One's system since the 1950s. They make up 50% of the HVI equipment that has reached ESL (30–50 years). Other HVI equipment, such as optical isolators and isolation transformers, is fairly new. Considerations that help establish the ESL for NTs include degraded insulation, underrated NTs and overall physical condition.

Microwave Radio Systems

Hydro One's fleet of microwave systems is fairly young. Microwave systems consist of two equipment types based on technology: (i) newer sub-T1 digital microwave systems and (ii) T1 digital microwave systems. The majority of sub-T1 digital microwave systems were installed in the last five to six years to provide communication to and from distributed generation customers, of which about 10% exceed their ESL. Some T1 digital microwave systems, however, are experiencing performance as well as maintenance issues where parts are difficult to source because of equipment obsolescence. Of the T1 type microwave systems, 52% are considered obsolete.

Hydro One considers the ESL for radio communication towers to be the same as that for transmission steel structures. Thus, an average ESL of 80 years is used for steel

structures assuming they have not yet been re-coated. About 75% of the towers are more than 40 years of age, but none are beyond 80 years. Unlike steel structures, communication tower failures that result in a complete tower collapse or a broken (or bent) tower member are very rare.

Provincial Mobile Radio System

The provincial mobile radio system includes 143 base stations and approximately 2,000 radios that connect the control centres to radio-equipped fleet vehicles and hand-held portable devices spread across Ontario.

The radio technology deployed for the existing PMRS is technologically obsolete. The equipment is no longer manufactured or supported and is considered beyond ESL. Procurement of strategic spares continues to present significant challenges, posing a risk to maintaining transmission system equipment or restoring power in remote areas safely and promptly.

2.2.2.5.3 ASSET LIFECYCLE

Hydro One's asset strategy for Power System Telecom is to provide robust and reliable telecommunications for the protection, control and operation of the transmission system by maintaining and replacing assets that pose safety, reliability or environmental risks.

Hydro One performs both preventive maintenance and corrective maintenance activities to proactively verify functionality, monitor performance and deterioration, and remediate deficiencies of Power System Telecom assets and systems to ensure their normal operational status and regulatory compliance. Hydro One also carries out strategic sparing as part of this essential asset maintenance program.

As part of its Power System Telecom asset lifecycle strategy, Hydro One will continue to work with vendors with the goal of maintaining sustainable product support windows, especially for microprocessor-based telecommunications devices.

2.2.2.5.3.1 INSPECTION AND MAINTENANCE PRACTICES

Hydro One's inspection and maintenance practices for Power System Telecom assets include time-based preventive maintenance, corrective maintenance and strategic sparing.

Time-based Preventive Maintenance

Hydro One maintains and field-tests all communication-system devices to verify that they are functional and meet performance criteria. Communication-system devices are maintained under Hydro One's Protection System Maintenance Program (PSMP), which is based on NERC PRC-005 (Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance). In addition, 48 VDC backup power supplies at certain sites identified by the IESO as critical for restoration of Ontario's transmission system are maintained in accordance with NPCC Directory No. 8 (System Restoration) requirements. More specifically, preventive maintenance for communication-system devices involves the following activities:

- **Routine Maintenance / Re-verification**. Routine maintenance is performed on SONET equipment, PLC radios, teleprotection terminal devices, and microwave radios, among others. Maintenance includes visual inspections, air filter replacements (if applicable), verification of performance parameters and checks on alarm monitoring modules.
- **Signal Adequacy Tests**. Signal adequacy testing is performed on PLC systems where the communication channels are unmonitored and do not have alarming capabilities.
- **Radio Communication Tower Visual Inspections**. Communication towers are inspected visually for functioning of aviation obstruction lighting, where remote monitoring is not available.
- **Telecom Battery / Charger Maintenance**. Maintenance of 48 VDC backup power batteries and chargers includes visual inspections, diagnostic test level 1 (equipment integrity check), diagnostic level 2 (AC interruption test) and battery load test.
- **Auxiliary telecommunication equipment inspections**. Inspections of HVI equipment verify its integrity, including condition, rusting, leaks and equipment

connections, and confirm that it does not pose a risk to reliability or safety. Overhead metallic cables are inspected for wear and tear as well as any safety hazards.

- **OPGW / ADSS maintenance and inspections**. Aerial inspections of OPGW and ADSS cables includes visual inspections for signs of excessive wear and other abnormal cable conditions, as well as inspection of associated attachment hardware.

Timing intervals for telecommunication equipment maintenance are dependent on the technology of the communications scheme and/or equipment, and whether the telecommunication equipment directly interfaces with protection schemes that form part of the BES. For BES protection schemes, the maintenance interval for telecommunication devices is non-discretionary (based on the NERC PRC-005 standard) and requires annual regulatory compliance reporting. Maintenance on non-BES elements is performed on longer time intervals in line with industry best practices.

Unmonitored communication systems are tested for signal adequacy every three months and maintained or reverified every five years, while self-monitoring devices with remote alarming capabilities are maintained on a 10-year interval. These maintenance intervals are more stringent than regulatory requirements to mitigate the risk of non-compliance by providing a buffer for cases where regulatory maintenance cannot be completed as originally scheduled because of operational limitations.

As time-based preventive maintenance work is performed, progress is tracked on a monthly basis and maintenance records are kept in a central repository. NERC and NPCC regulatory maintenance activities are reported on an internal compliance scorecard on a monthly basis.

Corrective Maintenance

Hydro One performs corrective maintenance to remedy defects identified during preventive maintenance and failure events. Corrective maintenance activities include fibre break repairs, telecommunication equipment repairs and diagnostic activities. Corrective

work is prioritized based on the urgency of restoring the affected asset to maintain safe and reliable operation of Hydro One's power system.

Strategic Sparing

Strategic sparing of Power System Telecom assets ensures that there are adequate operational spares available, such that all categories of equipment can be maintained, repaired or replaced in a timely manner.

Strategic sparing also ensures that all materials and test equipment are available to meet the requirements of Hydro One's Fibre Cable Emergency Response and Restoration Plan. The following activities are included in Power System Telecom sparing programs:

- Procurement of operational spares of all Power System Telecommunication equipment;
- Ensuring fibre cable emergency response capability; and
- Providing maintenance support to field staff.

In addition to tracking failure rates and determining maximum and minimum stock levels for Power System Telecom equipment to ensure adequate operational spares, Hydro One proactively monitors equipment that has been discontinued and is no longer supported by manufacturers. Similar to other utilities, Hydro One is presented with "last-buy opportunities" for strategic sparing of certain equipment, in which case Hydro One purchases spares as appropriate to support the installed base.

2.2.2.5.3.2 ASSET REPLACEMENT AND REFURBISHMENT

Telecommunication technologies typically have a 15-20 year ESL. Many of Hydro One's systems are now approaching their ESL and face technological obsolescence. Component repairs and operational sparing to maintain safe and reliable operation of the PSTS network become increasingly challenging for assets with diminishing or discontinued vendor support.

Hydro One continues to address the sustainment needs of Power System Telecom assets to maintain safety and reliability and meet communication system performance

requirements. This will be achieved by systematically phasing out beyond ESL and/or obsolete equipment from the asset base while also working with suppliers to extend product support to reduce equipment obsolescence.

Technological obsolescence remains the primary focus for the majority of replacement needs and as a result, new technologies are being sought where existing ones are obsolete and no longer meet Hydro One's business requirements. Hydro One is currently:

- Replacing the obsolete SONET network with Multiprotocol Label Switching (MPLS) technology as the majority of first generation SONET equipment exceeds ESL and has very limited vendor support;
- Sustaining and phasing out obsolete and poor performing Power System Telecom assets that have reached their ESL. This includes obsolete PLC systems, teleprotection terminal devices, HVI equipment and microwave radio systems;
- Evaluating and piloting satellite-based solutions for the replacement of PMRS in order to ensure continuity of voice communication services;
- Refining maintenance programs, policies and practices to ensure that they meet the lifecycle optimization, reliability and regulatory requirements as dictated by NERC and NPCC; and
- Continuing to lease carrier-based services from telecommunication providers to provide PSTS where Hydro One-owned communication facilities are not economical.

Integrated station projects, shieldwire replacement program, and line refurbishment projects will drive the majority of the replacements of key telecommunication assets to meet Power System Telecom sustainment and development needs. In this way, Power System Telecom assets can be bundled with other work at a particular station so as to achieve execution efficiencies.

As Hydro One migrates its existing PSTS to new technologies, SONET infrastructure replacement is sought with additional foresight to new application requirements such as non-operational data, remote condition-based monitoring and synchrophasor technology. ADSS cable and microwave system replacements will lead to fewer failures and

performance issues leading to a more robust and reliable power system communication network.

Replacement of SONET Network

Given the obsolescence of both the technology and network equipment on which SONET is built, as well as diminishing vendor support and hardware spares availability, Hydro One has developed a migration plan towards a modern solution and the project is currently in execution. The replacement of SONET terminal equipment on Rings 1-9 will begin in 2026.

IP-Based Communications for Teleprotection Applications

Legacy leased analog and digital circuits offered by carriers which are based on carrier time-division multiplexing infrastructure are no longer supported. Moreover, telecommunication carriers no longer guarantee performance for analog leased circuits due to obsolescence and have indicated that some of these circuits will not be available in the near future.

Hydro One is testing and validating new IP-based technologies for teleprotections to migrate away from legacy carrier-based leased services. This will involve replacement of legacy terminal communications equipment, as well as legacy leased copper facilities into Hydro One stations with new fibre infrastructure.

Expansion of Fibre Optic Cable Infrastructure

The use of fibre optic cable as a communication medium has become a viable alternative for providing reliable high-speed communication between Hydro One stations.

There is a foreseen need to expand the footprint of fibre cable infrastructure in order to:

- Meet the evolving communication needs for connecting Hydro One stations;
- Displace obsolete technologies such as microwave, PLC and legacy carrier-based leased services; and
- Improve communications reliability

Hydro One's primary focus is to replace SONET microwave links, leased facilities and PLC systems with OPGW, where economically feasible for improved system reliability.

New Provincial Mobile Radio System

As the technology used for the existing PMRS is obsolete with equipment no longer manufactured or supported, the PMRS infrastructure will be replaced. The planned provincial mobile radio replacement project will:

- Pursue a hybrid Low-Earth Orbit (LEO) satellite/cellular/radio solution to replace the existing PMRS.
- Examine the infrastructure required to ensure necessary coverage across Hydro One's service areas.
- Complete a competitive bidding process for the solution.
- Integrate the new system into Hydro One's control centres and deploy the new solution across Hydro One's field crews.

2.2.3 ASSET COMPONENT INFORMATION - OTHER STATION COMPONENTS

This section discusses the other power equipment found in transmission stations, including switches, capacitor banks, instrument transformers, ancillary equipment, and civil infrastructure.

2.2.3.1 ASSET DESCRIPTION / PURPOSE

Hydro One transmission stations contain a number of other components that are essential to support the functionality of major station assets and system operation. These components are categorized as:

- Other Power Equipment;
- Ancillary Equipment; and
- Civil Infrastructure.

Other Power Equipment

Other Power Equipment refers to devices connected to the power system (operating at voltages greater than 1 kV) that are not transformers or circuit breakers. Table 24

summarizes these other high-voltage (HV) and medium-voltage (MV) power equipment assets.

Table 24 - Other Power Equipment Description

Asset	Description
Switches	Disconnect switches are used to visually and electrically isolate sections of the transmission system for maintenance, safety, and other operational requirements. Ground switches are used to de-energize circuits or buses which cannot be done with portable grounds alone.
Capacitor Banks	Capacitor Banks provide voltage support to maintain power transmission efficiency. They are switched in and out of the system based on operating needs.
Static VAR Compensators	Similar to capacitor banks, Static Var Compensators (SVCs) provide voltage support for efficiency. These units are more complex but offer rapid, automated variable reactive support through the use of thyristor switching.
Reactors	Reactors are inductive devices that serve to limit current when connected in series, or to reduce the system voltage when connected in shunt (operated in an opposite manner to capacitor banks). Some large shunt reactors are similar in construction to large, oil-filled transformers, and the rest are dry-type coils that are maintenance free.
Instrument Transformers	Instrument transformers convert high voltages and currents into proportionately lower values that are used for measurement by protection and control devices. There are three types of instrument transformers: voltage (potential) transformers (PTs), capacitive voltage transformers (CVT) and current transformers (CTs).
Insulators	Insulators serve to mechanically support live components operating at system voltages, providing adequate electrical clearance to structures and other equipment.
Surge Arresters	Surge arresters limit the peak voltage of system transients to protect the insulation of power equipment.
GIS/GIL	Gas insulated switchgear consists of pressurized gas metal-enclosed compartments which house components such as breakers, switches, bus, etc. These types of installations are more compact but require additional maintenance compared to air insulated systems.

<u>Ancillary Equipment</u>

Ancillary Equipment enables protection and control (P&C) equipment and power equipment to operate as expected. AC/DC station service equipment, DC batteries and chargers, and high-pressure air systems are considered ancillary equipment. Table 25 summarizes these ancillary equipment assets.

Table 25 - Ancillary Equipment Description

Asset	Description
AC/DC station service equipment	AC/DC station service equipment consists of many types of low-voltage (below 1 kV) sub-equipment such as AC station service transformers, AC/DC breakers, AC/DC switches and AC/DC transfer schemes. Station service equipment provides power to circuit breakers and protection and control equipment as well as auxiliary equipment such as fans, pumps, heating and lighting.
DC Batteries and Chargers	All transmission stations have at least one station DC system to ensure a source of power is available for power equipment operation under all system conditions. Batteries and chargers provide secure DC power within the station. The chargers convert AC into DC to supply the station DC load and charge the batteries.
High Pressure Air System	Centralized high-pressure air systems (HPA) are installed at all locations that have ABCBs. The system consists of a centralized HPA compressor/dryer plant, an air storage facility, extensive piping and valve arrangements and controls.
Grounding	Grounding is a complex network of buried and surface conductors intended to carry fault and transient currents from power equipment and disperse them into the soil. Grounding systems ensure that fault protection operates and limit the voltages to which workers and the public are exposed on structures they can touch.

Civil Infrastructure

Civil infrastructure consists of the physical structures such as station structures, fences and gates, spill containment, security and fire protection, etc. within the transmission station perimeter. Table 26 summarizes these civil infrastructure assets.

Table 26 - Civil Infrastructure Description

Asset	Description
Station Structures	Station structures are used in stations for mounting electrical equipment such as switches, fuses, breakers, station service transformers, bus, and IEDs. Some station structures are wooden, though most are made of steel. The earliest station structures were built in the 1920s.
Fences and Gates	Fences and walls are used to separate live station equipment from the public to maintain public safety. Gates are used as an entry point for Hydro One vehicles, equipment and staff. Most station fences are chain link, though some are wooden.
Spill Containment Systems	Spill containment systems are present in stations that pose a possible detrimental effect to the environment if a spill were to occur (e.g., near a river or pond). These spill containment systems collect transformer oil in the event of a transformer tank rupture.
Security and Fire Protection	The Security and Fire Protection asset class includes systems that protect transmission station facilities from fire, break-ins and vandalism. The security systems include additional measures ranging from conventional door control security systems to video surveillance facilities. The fire protection systems are primarily of two types: those associated with buildings and those associated with equipment.
Station Site and Yard	Station site and yard are site elements including station drainage and geotechnical systems, vegetation/weed management inside the station, gravel, garbage, road infrastructure, etc.

2.2.3.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.3.3 ASSET DEMOGRAPHICS

Hydro One has over 25,000 individual Other Station Components present in transmission stations, as summarized in Table 27. HOSSM's Other Station Components are summarized in Table 28.

Table 27 - Hydro One - Other Station Component Demographics

Component	Type	Quantity
Other Power Equipment	HV/MV Switches	16,924
	HV/MV Instrument Transformers	8,661
	HV/MV Capacitor Banks	400
Ancillary Equipment	Station DC Batteries and Chargers	884
	AC/DC Station Service Equipment	1,358
	High Pressure Air Systems	112
Civil Infrastructure	Buildings	925
	Infrastructure	251
	Fences and Gates	391
	Spill Containment	635
	Fire and Security Systems	647
	Sites and Yards	637

Table 28 - HOSSM – Other Station Component Demographics

Component	Type	Quantity
Other Power Equipment	HV/MV Switches	267
	HV/MV Instrument Transformers	195
	HV/MV Capacitor Banks	2
Ancillary Equipment	Station DC Batteries and Chargers	44
	AC/DC Station Service Equipment	24
	High Pressure Air Systems	0
Civil Infrastructure	Buildings	15
	Infrastructure	15
	Fences and Gates	15
	Spill Containment	12
	Fire and Security Systems	15
	Sites and Yards	15

A more detailed discussion regarding asset demographics, condition and/or performance (as applicable) of Other Station Components is provided below for the main asset types.

Other Power Equipment - HV/MV Switches

Switches provide isolation for system control, establishing safe work zones and sectionalizing faulted equipment. The typical mode of failure for a switch is a mechanical

problem requiring that it be wired shut or bypassed. Providing isolation at that point then requires a much wider and therefore riskier outage to the next set of functioning switches; and if this is not acceptable for the outage period, then manual disconnection and later reconnection of the bus must be added to the work. The economic impact of a non-functioning switch extends beyond its maintenance costs and asset value. Non-functioning switches increase the system risk not only with these wider outages, but through cancelled maintenance work, impact to customers and delays and added cost to capital projects.

Approximately 6,671 (39%) of Hydro One's HV and MV switches are 40 years or older, with an ESL ranging from 40 to 50 years. Currently, 14% of the switch fleet is responsible for the majority of recorded defect reports. The rest of the defects are evenly distributed and representative of the fleet demographic. Switches are replaced primarily due to obsolescence as part of larger integrated investment projects, and the good units are retained as spares to support the remaining population. Poor condition of switches poses an increased risk to health and safety. The potential for musculoskeletal disorder (MSD) injuries increases as switches become more difficult to operate due to lack of lubrication and seizing. As the switches become more difficult to operate additional force is applied to the insulators which can break and fall onto personnel or other equipment. Individual replacements are performed only on broken switches that cannot be repaired, regardless of age. Proactive replacements are targeted to small populations with poor performance.

Other Power Equipment - HV/MV Capacitor Banks

Hydro One manages approximately 402 HV and MV capacitor banks. The ESL for capacitor banks is from 30 to 40 years. 39% of the fleet is either beyond ESL and/or in poor condition.

Other Power Equipment – Static VAR Compensators (SVCs)

Hydro One operates five SVCs with an average age of 15 years. 40% of these systems have ongoing operational issues with continuing repairs. SVCs require more maintenance than other capacitors due to their extensive control and cooling systems. Most

deficiencies reported are related to the cooling system such as leaks, pump failures and coolant top ups or replacements.

Other Power Equipment – Insulators, Surge Arrestors and Cable Potheads

Hydro One buses have tens to hundreds of insulators per bus, depending on size, design and voltage. These are typically expected to last the life of the conductor and are only replaced with the assets they support during larger station refurbishment programs. In some cases, the life of the conductor has been exceeded and insulators are beginning to fail. There are approximately ten unplanned outages annually in transmission stations from failed insulators and about 90 more that do not cause an outage. Approximately half of these failures occur during switching operations and typically do not cause outages because equipment is in the process of being isolated, but they can cause delays for outage work. These events are dangerous to staff who could be struck by falling equipment when the insulator breaks. Like insulators, former technologies used porcelain for surge arresters and potheads. These designs are reaching end of life and have the potential to fail explosively. Potheads are typically replaced with cables, which generally have a longer service life than other assets.

The table below shows common insulator failure modes. These insulators exist in various quantities in approximately 30% of transmission stations and have resulted in equipment failure.

Table 29 - Station Insulator Common Failure Modes

Type	Age	Voltage	Failure Mode
Cap & Pin	All	All	Cement growth and shed cracking
79” Multicone	Pre-1990	230 kV	Grout deterioration between porcelain shells
79” COB 3 Stack Post	Pre-1990	230 kV	Prone to premature failure
COB Strain	1960-1982	All	Radial cracks due to cement growth at hub pin and porcelain

Other Power Equipment - HV/MV Instrument Transformers

Hydro One manages more than 8,800 free-standing instrument transformers, of which approximately 5,100 are high-voltage instrument transformers (HVITs) and 3,700 are medium-voltage instrument transformers (MVITs). The fleet of HVITs and MVITs measures voltage and current for various purposes, such as monitoring the state of the grid, detecting faults and metering usage. The ESL varies from 30 to 50 years. As an example, capacitor voltage transformers, a type of HVIT, have an ESL of 30 years, like power capacitors. Overall, approximately 21% of the free-standing instrument transformers are beyond their ESL; approximately 17% of the MVIT population is beyond ESL and approximately 23% of the HVIT population is beyond ESL.

Other Power Equipment – GIS/GIL Systems

Hydro One has 15 transmission stations with gas-insulated switchgear installations operating at 115 kV and above, and an additional 16 stations with MVGIS switchgear. ESL varies from 40 to 50 years for all voltages. Almost 60% of HV installations are 40 years or older and pose significant environmental and reliability risks due to an increased probability of failure or leaks, which can result in SF_6 gas emissions and/or forced outages. In the last two years, there have been three component failures due to insulation breakdown and partial discharge that required replacement. The air-to-gas bushings can develop leaks at seals and typically need replacement. MVGIS equipment is much newer, with all installations being 20 years old or newer.

Ancillary Equipment - AC/DC Station Service

Hydro One manages more than 1,300 AC/DC station service equipment devices. ESL varies between subcategories such as switches, transfer schemes, and breakers, but on average 40 years is considered the appropriate ESL. Some equipment is facing obsolescence issues due to difficulties in obtaining parts while others have particular failure modes that require routine attention. Any older non-standard configurations that are more likely to pose a high arc-flash hazard to maintenance personnel are priorities for replacement. Approximately 29% of transmission stations contain AC/DC station service equipment that are beyond ESL, in poor condition, have a known safety risk, and/or are obsolete.

Ancillary Equipment - DC Batteries and Chargers

Hydro One manages 926 station battery banks and battery chargers, which supply DC power to protection and control and other station ancillary equipment. The ESL for batteries is 10-20 years depending on type and 20-40 years for battery chargers depending on type. 22% of batteries and 7% of chargers are currently at ESL and/or in poor condition Batteries are vital to power restoration following system outages. Losing batteries or chargers can impact system reliability, outage restoration, and protection of power system equipment since the DC power supply to P&C equipment would be jeopardized.

Ancillary Equipment - High Pressure Air (HPA) System

Hydro One has HPA systems left at three transmission stations that use ABCB, including 13 compressors, 10 dryers, 77 air receivers, and other related HPA ancillary systems. These assets generally experience minor leaks from the compressor, dryers or air lines. Leaks or failures in the HPA system can result in the removal of high voltage ABCBs from service until repairs can be completed. ABCBs are primarily installed at bulk transmission stations, and are critical in supporting bulk power flows within Ontario and through international tie lines. Through the replacement of the ABCB fleet, the associated HPA system will be removed as it will no longer be needed.

Civil Infrastructure

Civil Infrastructure assets are comprised of station drainage systems, yard surface/subsurface, access roads, structural footings, foundations, perimeter fencing, fire detection/protection, yard lighting and cable trenches. These systems provide infrastructure and support services to station equipment and station environmental systems. Asset condition is determined by monthly visual inspections and resulting deficiencies are a measure of the overall condition.

Foundations, footings, spill containment and asphalt roads can heave and crack due to freeze/thaw cycling. Drainage systems are made of clay piping and can deteriorate and/or collapse as they age. Station fences and gates are damaged or otherwise compromised

by thieves seeking to gain access to yards to steal copper grounds. Theft creates additional safety hazards and potential power quality issues.

Many stations are exhibiting advanced deterioration of critical infrastructure components, including access roads, concrete footing supporting low- and high-voltage structures/equipment, perimeter fencing, and cable trays and lids. If left unaddressed, there will be increased risk of equipment failure, safety hazards, and restricted site access for both maintenance and operations.

2.2.3.4 ASSET LIFECYCLE

With respect to this asset class, Hydro One's strategy is to proactively manage the asset fleet through inspections and routine maintenance to monitor condition and ensure compliance with applicable regulatory standards (including requirements of NERC/NPCC and Ministry of Environment, Conservation and Parks). Repair versus replacement assessments are performed case-by-case based on the risk from a demographic, condition, environmental, utilization, economic, and customer perspective, as balanced against asset needs, asset reliability, safety risk and costs for the overall fleet. Additionally, decisions include the use of financial models to estimate the most economical option for the asset.

2.2.3.4.1 ASSET INSPECTION AND MAINTENANCE PRACTICES

Hydro One performs visual inspections, thermographic surveys and periodic testing of power and ancillary assets.

Other Power Equipment

While a minority of Other Power Equipment devices require periodic testing similar to transformers or breakers, most only have maintenance in the form of visual and thermographic inspections. Instrument transformers, capacitors and dry-type shunt reactors are monitored continuously for changes in impedance. Upon finding hot spots, oil leaks, corrosion, erosion, distortion, dysfunction, animal intrusion or other damage, maintenance staff would file a defect report to perform corrective maintenance such as cleaning, adjustment or component change.

Hydro One tailors switch maintenance depending on their make and function. Switches enclosed in GIS receive gas testing of their compartments and contact resistance testing. Some high-voltage, outdoor, disconnect switches are known to come out of adjustment, and require complete outages for realignment. The bulk of the fleet, however, does not necessarily require regular adjustment or component replacement, but may tend to seize and become difficult to operate, risking damage to the equipment and injury to personnel. For example, a hookstick switch requiring excessive manual pull force may cause the insulators to break and components to fall to the ground where the worker is standing. Other types of stuck switches may cause burnt motors, stripped gears, burnt clutches and broken linkages. An out-of-adjustment switch may fail to close properly, which will burn out its contacts. For MV outdoor switches, Hydro One is continuing to utilize live lubrication and exercising. This will help maintain better functionality, ensure that problems are detected, recorded and attended to in a timely manner, and improve overall switch availability. Like other equipment, switches receive regular visual and thermographic inspections.

With respect to HV/MV capacitor banks, visual and thermographic inspections detect inadequate connections, blown fuses, broken insulators, degraded structures and bulging or leaking units, which are addressed through corrective maintenance.

Since instrument transformers continuously send measured signals to SCADA, abnormal values are an immediate indicator of dysfunction. Some are also subjected to regular insulation tests or oil tests. All receive regular visual and thermographic inspections.

Ancillary Equipment - AC/DC Station Service

On low voltage AC/DC station service equipment (such as transfer schemes, switchgear, switches and breakers), significant damage, deterioration, or loss of functionality identified through inspection or alarms are addressed through the appropriate remedial action. Inspections of AC station service breakers include manual operation tests, inspection of all internal components, insulation condition, contacts and rack-in mechanisms (where applicable).

Ancillary Equipment - DC Batteries and Chargers

Hydro One maintains batteries and chargers by inspecting and verifying various condition and performance metrics in line with industry standards. Visual inspections are performed every 4 to 12 months, diagnostics testing is performed every 6 to 12 months and battery load testing is performed every 3 to 5 years depending on battery type and station criticality. As prescribed by applicable standards, maintenance activities include visual inspections and recording of critical battery and charger values. Other scheduled maintenance includes inspection of battery plate condition, conductance measurements, capacity and continuity testing of the DC system and battery load tests.

Ancillary Equipment - High Pressure Air System

Inspections include dryer and compressor condition checks, leak detection, verifying subcomponent operation, measuring dryer moisture content, and assessing and recording indicator, level and run time values. Other scheduled maintenance includes function testing, overhauling and component replacement where necessary. In compliance with Technical Standards and Safety Authority (TSSA) regulations, pressure relief valves are tested every 3 to 5 years.

Civil Infrastructure

Visual inspections are performed to assess the condition and functionality of an array of assets including below grade cable penetrations, station roadways, perimeter fencing/gates, structure footings/foundations, railway spur lines, site storm drainage, yard stone and cable trenches/trays. Also included is testing of building fire alarm systems and deluge systems where applicable; in compliance with the Fire Code and Ontario Building Code.

Visual inspections are performed to assess the condition and functionality of spill control systems, which include spill containment pits, passive/mechanical oil-water separators, management of individual station environmental compliance approvals and any effluent testing/monitoring required to comply with the Ministry of the Environment, Conservation and Parks.

2.2.3.4.2 ASSET REPLACEMENT AND REFURBISHMENT

The replacement and refurbishment strategy for other power equipment, ancillary equipment, and civil infrastructure varies due to differences in their respective functionality and modes of failure.

Other Power Equipment

When corrective maintenance is insufficient to restore the function of Other Power Equipment devices, the device is recommended for replacement. Depending on the nature of the problem and associated system impact, the device may be replaced with a spare on the same day, planned for a convenient date, or wait to be included in an integrated investment project.

Ancillary Equipment

With respect to low voltage AC/DC station service equipment, refurbishment or replacement is considered if field inspections indicate poor condition and if spare parts are obtainable.

Batteries and chargers are considered for replacement if they are found to be in significant degraded condition or insufficient capacity based on assessments and diagnostic testing.

With respect to HPA systems, ABCB replacements drive the timing of decommissioning. By 2030, the few remaining HPA systems are expected to be removed from the system. Hydro One will continue to maintain HPA systems while ABCBs remain in-service at certain stations. As ABCBs are replaced, maintenance costs are expected to decrease for HPA air systems.

Civil Infrastructure

Hydro One will continue to perform visual inspections and preventive maintenance to assess the condition and functionality of Civil Infrastructure to ensure safe, reliable and compliant assets.

2.2.4 ASSET COMPONENT INFORMATION – TRANSMISSION LINES

This section discusses the main transmission line assets that support the operation of Hydro One's transmission system, including overhead conductors, underground cables, structures, foundations, insulators, and shieldwires.

2.2.4.1 OVERHEAD CONDUCTORS

2.2.4.1.1 ASSET DESCRIPTION / PURPOSE

The overhead conductor is the critical asset responsible for electrically connecting system nodes. Over 99% of Hydro One's transmission system is comprises overhead power lines, with the balance being underground connections. 98% of Hydro One's overhead conductor fleet utilizes aluminum conductor steel reinforced (ACSR) type conductors, with copper, aluminum and aluminum conductor steel supported (ACSS) type conductors making up the balance. Overhead conductors are supported by a variety of structures and are interconnected using splices and dead-end connectors, in-span and at dead-end structures respectively.

2.2.4.1.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

Hydro One's transmission overhead conductor fleet has an average age of 58 years, with an ESL of 90, 70 and 100 years for ACSR, copper and aluminum conductors, respectively. ACSS conductors are relatively new and do not have an established ESL. It is important to note that replacement and investment decisions are based on condition (not ESL), as further discussed below. However, asset age is useful as a screening criterion, triggering condition assessments on overhead conductors that are 50 years of age or older. Table 30 summarizes the demographic profile of Hydro One's overhead conductor fleet (excluding the HOSSM system).

The HOSSM system has an average age of 36 years and comprises of 99% (538 km) ACSR conductors and 1% (5 km) aluminum conductors. The demographic profile of the HOSSM system is shown in Table 31.

Table 30 - Hydro One Overhead Conductor Demographics

Type	Quantity (km)	Average Age (Years)	ESL (Years)	Beyond ESL (km)
ACSR	27,756	58	90	2,752
Copper	243	111	70	243
Aluminum	26	101	100	20
ACSS	154	11	–	–
Total	**28,178**	**-**	**-**	**3,016**

Table 31 - HOSSM Overhead Conductor Demographics[14]

Type	Quantity (km)	Average Age (Years)	ESL (Years)	Beyond ESL (km)
ACSR	538	36	90	0
Copper	0	0	70	0
Aluminum	5	31	100	0
ACSS	0	0	-	-
Total	**543**	**-**	**-**	**0**

2.2.4.1.3 ASSET CONDITION

In almost all cases, overhead conductors functionally deteriorate mechanically before they deteriorate electrically. For this reason, Hydro One primarily assesses conductors for mechanical deterioration using the testing methods discussed in the Asset Inspection and Maintenance Practices section below. Deterioration of an overhead conductor cannot be stopped or reversed. When deterioration is discovered at a tested location, similar levels of deterioration are expected at multiple points along the entire conductor line section of the same vintage and type. Deterioration differs from localized conductor damage due to trauma such as a tree fall, lightning strike or vandalism. In such cases, the resulting damage is limited to the immediate area and can be remediated through localized repairs.

The demand on a conductor's rated mechanical strength is not significant during normal operating conditions, during which time conductor tension can be as low as 15% of rated tensile strength. However, during adverse weather conditions, especially in the presence of ice accumulation, the tension on a conductor can rise to over 90% of rated tensile

[14] As set out in Schedule 1 of HOSSM's Transmission Licence, its system also includes 11 circuit-km of 44 kV lines and associated equipment which have been deemed by the OEB as serving transmission function under Section 84 of the Ontario Energy Board Act, 1998.

strength. Across Ontario, Hydro One's conductor fleet is regularly exposed to strong winds and ice accumulation. As the population of deteriorated conductors increases, so does the overhead conductor fleet's susceptibility to failure when mechanically stressed; for example, during adverse weather events.

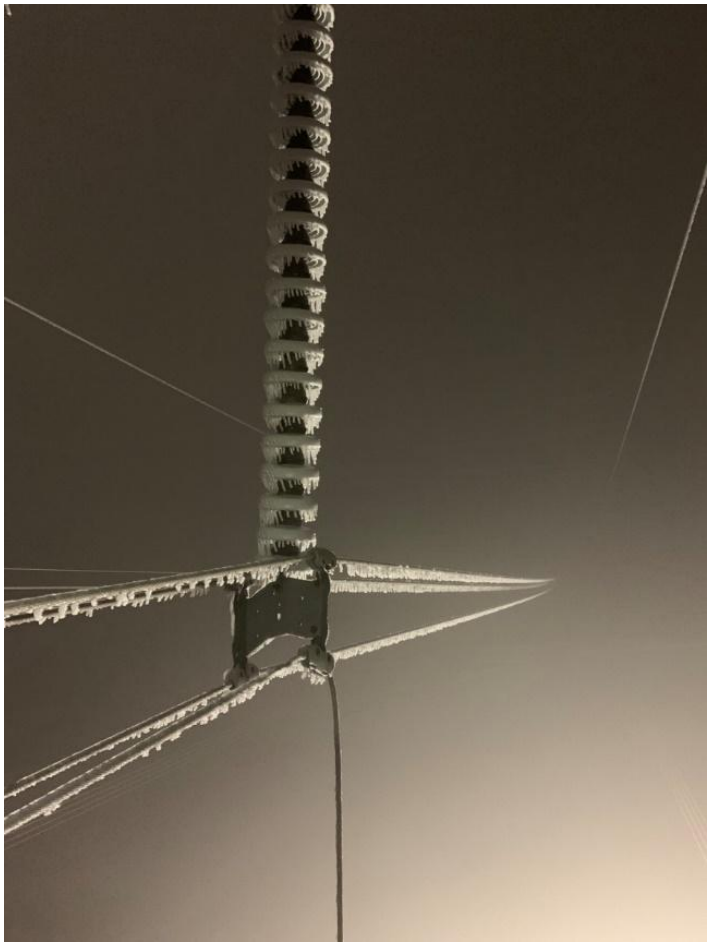

Figure 16: Broken Conductor on an Ice Accumulated Circuit B501M

Hydro One verifies the condition of its conductor fleet empirically by testing the conductor itself and its connecting hardware subcomponents. In many cases, deterioration is discovered on both the conductor itself and its subcomponents concurrently. Deterioration that is identified on a subcomponent only, such as connectors, would be considered a subcomponent issue and not attributed to the deterioration of the overall conductor system. Testing is limited to conductor spans greater than 50 years of age since based on Hydro

One's operating experience, conductors less than 50 years of age have a low likelihood of being in a deteriorated condition and are therefore assumed to be in good condition.

Figure 17 shows the condition distribution of Hydro One's transmission conductor fleet, excluding the HOSSM system. Presently, 3,079 circuit-km (11%) of Hydro One's conductor fleet is verified to be in poor condition, with 5,296 circuit-km (19%) in fair condition. The subset of conductors in poor condition includes legacy copper conductors that can no longer be repaired because interfacing subcomponents are out of production. Fair-condition conductors are those that have started exhibiting deterioration, but not to the extent of being functionally compromised. Since the last application, the set of conductors in poor condition has decreased from 14% to 11% of the fleet. This decrease is attributed to replacements through renewals and decommissioning. However, the population of fair-condition conductors has materially increased from 12% to 19% of the fleet since the last application. This indicates that the population of the fleet exhibiting at least some deterioration has increased from 26% to 30% since the last filing.

With respect to the HOSSM system, 23 circuit-km (4%) of the fleet is in fair condition, 362 circuit-km (66%) is in good condition and the balance awaits testing. Figure 18 shows the condition distribution of the HOSSM transmission conductor fleet.

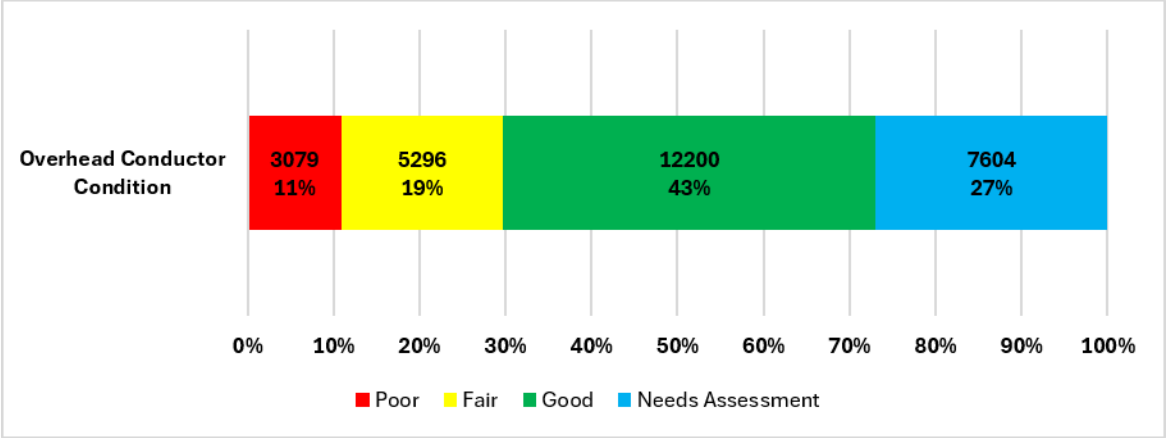

Figure 17: Hydro One – Overhead Conductor Condition

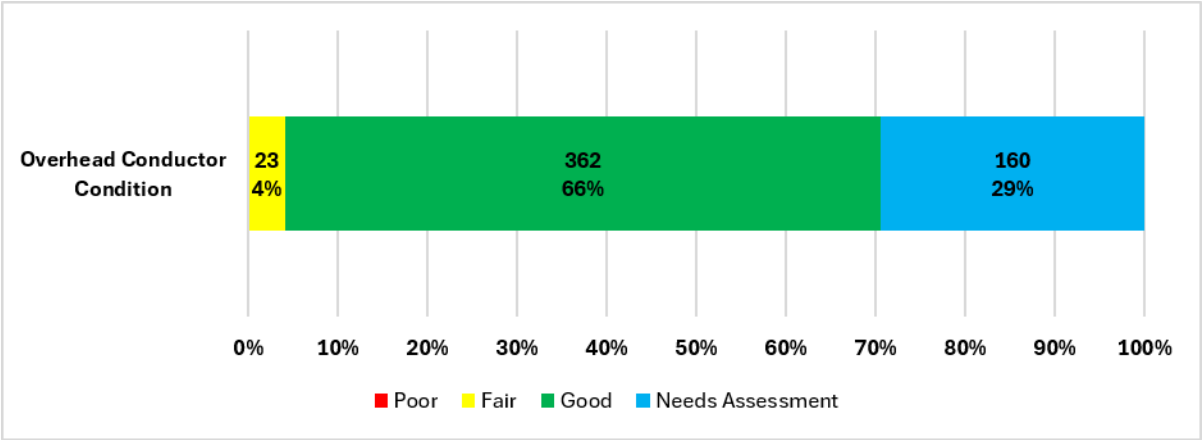

Figure 18: HOSSM – Overhead Conductor Condition

2.2.4.1.4 ASSET PERFORMANCE

Hydro One aims to proactively identify and replace conductors that are in poor condition before deterioration leads to equipment failure and adverse impact on safety and reliability. Given that reliability performance is a lagging indicator of the condition of the conductor fleet and that Hydro One's transmission system configuration enables a high degree of redundancy, by the time adverse impact on reliability metrics materializes, the condition deterioration and performance degradation of conductors at the asset level would already be significant and thus require significant investments to remediate. The consequences of a failed transmission overhead conductor – primarily safety and secondarily reliability – are further discussed below:

Safety

Transmission lines are in the public domain, and failure of a conductor can lead to the overhead line dropping along with its hardware, which endangers people and property nearby. A typical transmission line span is 300 metres at a height of approximately 30 metres. At approximately 1.6 kg/m, a falling conductor span is equivalent to a 480 kg metallic mass falling from a height of 30 metres. Furthermore, in the rare case where protection systems fail to operate, a fallen conductor can remain energized, presenting an added danger of electrocution or fire to surrounding areas. Figure 19 shows a car with shattered rear glass caused by the centre phase of circuit M32S dropping on it and several other parked cars in July 2026. This was caused by a failed connector.

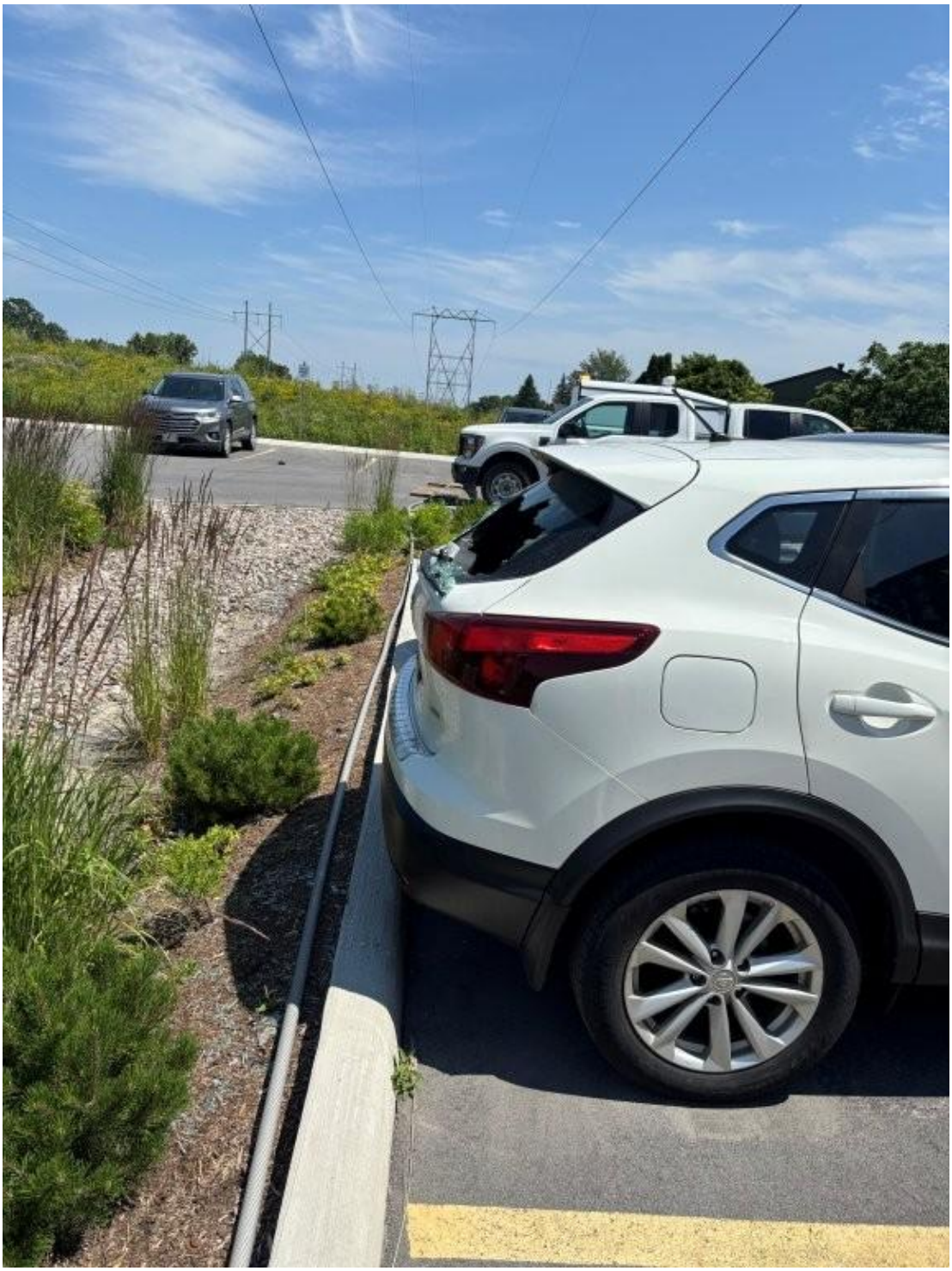

Figure 19: Dropped centre phase conductor of Circuit M32S in July 2026, damaging multiple parked vehicles

Reliability

All conductor failures lead to a circuit outage; however, not all conductor failures result in a customer outage. In the desired operating scenario, Hydro One's dynamic grid can switch supply from a failed circuit to an operational one. However, where this is not possible (e.g., due to inadequate available capacity), a failed circuit can cause a cascading outage of multiple circuits and interrupt numerous customers. Even where the conductor failure does not lead to an outage, it will affect system redundancy and the ability to obtain outages needed for planned maintenance and replacement work on other lines or station equipment. For example, in 2020, a 500 kV circuit, N581M, experienced conductor fraying that resulted in a forced outage. N581M is a critical element of the IESO-controlled Southern Ontario System; therefore, this unplanned outage resulted in the recall of numerous planned outages, delaying bus and switch work at Nanticoke TS and Middleport TS and work on circuits M20D and M21D. This outage also resulted in temporarily supplying Imperial Oil's Nanticoke refinery from a single bus, a state of reduced contingency. Restoring circuit N581M required an outage on its connecting bus. Given the aforementioned conflicting planned outages and the need to meet IESO's N-1 contingency scheme, N581M remained out of service for over 380 hours before adequate outages were available to perform repairs.

As shown in Figure 20 and Figure 21, the frequency and duration of outages provide a present picture of how the conductors are performing, but do not drive investment decisions on conductor replacements. As lagging indicators, there is a delay between when aggregate conductor condition degrades and when this results in degraded performance. Many of Hydro One's conductors are in publicly accessible areas. A fallen conductor can result in injuries to people or damage to property in the vicinity. If Hydro One waits to address poor-condition conductors until there is a noticeable effect on performance, the conductor fleet may have significantly degraded, resulting in a large number of conductor segments failing at the same time (for example, during a province-wide weather event). This would require significant effort and resources to mitigate and result in an unacceptable impact on customers in terms of both reliability and costs, in addition to the safety risks. For these reasons, Hydro One does not run its transmission assets to failure and instead replaces poor-condition assets based on a robust condition-

based assessment process. The number of forced outages (excluding force majeure weather events) due to conductor failures has been steady over the past ten years, as shown in Figure 20. Outage duration, shown in Figure 21, is influenced by the location of the conductor outage and the feasibility of the repair. Broken conductors in remote locations or conductors requiring adjacent outages for safe access have longer outage durations due to access difficulties. HOSSM has experienced a minimal number of conductor-related outages.

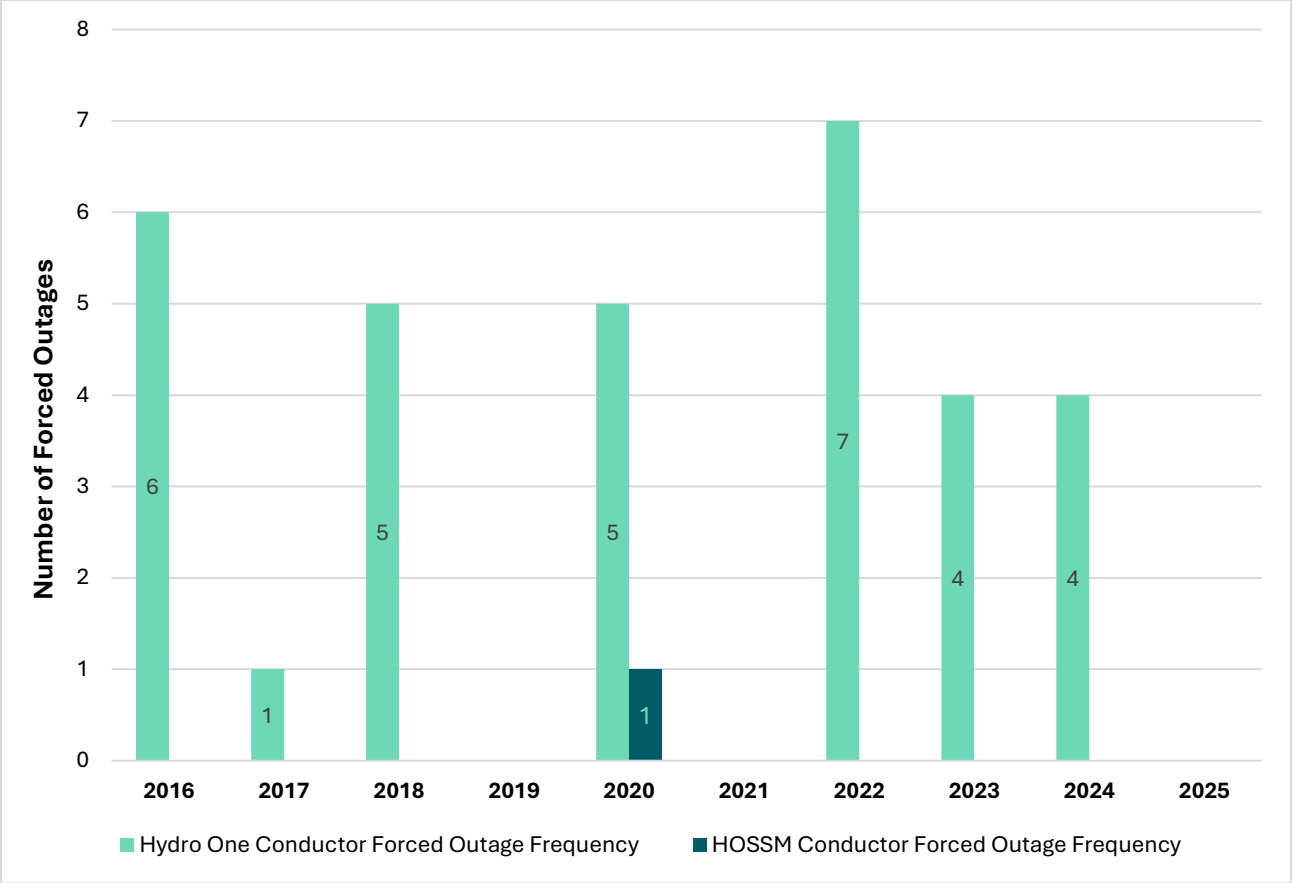

Figure 20: Overhead Conductor Forced Outage Frequency

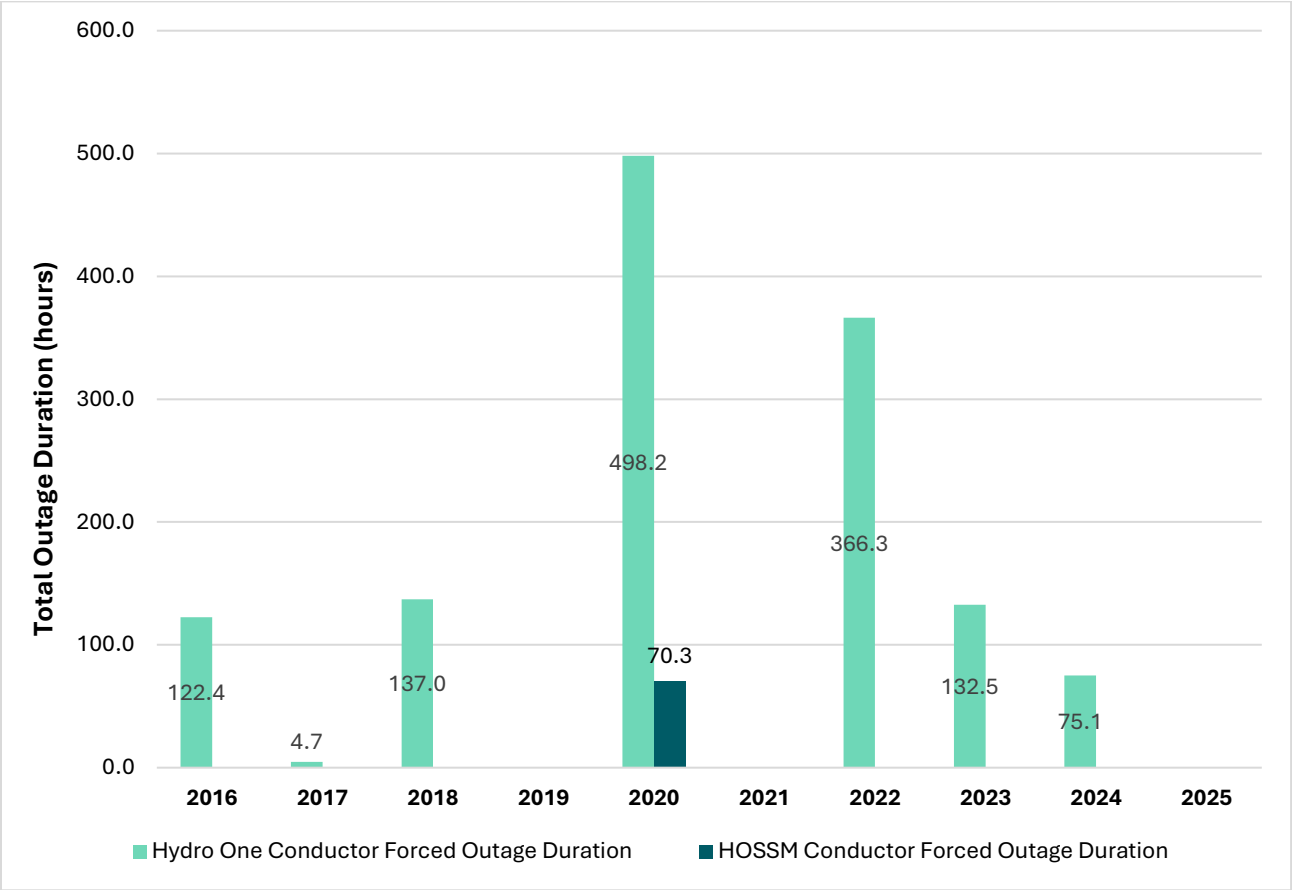

Figure 21: Overhead Conductor Forced Outage Duration

2.2.4.1.5 ASSET LIFECYCLE

Hydro One aims to ensure its overhead transmission conductor fleet can transmit electricity safely, reliably and efficiently between system nodes. To achieve this, Hydro One identifies and replaces deteriorated conductors proactively prior to failure, while seeking to maximize the service life of its installed conductors.

2.2.4.1.5.1 ASSET INSPECTION AND MAINTENANCE PRACTICES

Transmission overhead conductors do not deteriorate in a predictable manner. Hydro One has established an ESL of 90 years for its ACSR conductors, the predominant overhead conductor type in its fleet. However, the actual life span of each conductor has been observed to vary between 50 and 120 years, as numerous uncontrollable variables can affect conductor deterioration, including manufacturing quality, location, installation

orientation, local atmospheric contaminant levels, weather cycles, and stringing tension. For this reason, empirical testing is the only way to assess the condition of the conductor fleet. Condition assessment begins when a conductor has been in service for 50 years. Hydro One's conductor fleet is regularly visually inspected through helicopter and ground patrols, as discussed below under "Cyclical Based Maintenance Activities". These visual patrols aim to spot damaged conductors or external dangers to an overhead line. Visual inspection cannot assess a conductor's condition as deterioration is predominantly not visibly observable.

Hydro One performs testing to empirically establish the condition of its conductors, which allows Hydro One to operate verified good condition conductors well beyond their ESL. This approach prevents the replacement of conductors that do not need replacement, regardless of age, thereby maximizing asset useful life. More specifically, Hydro One uses Kinectrics LineVue scans, laboratory testing, or a combination of both to establish the condition of its conductors.

LineVue

Since 2016, Hydro One has performed the majority of its ACSR conductor condition assessments using the Kinectrics LineVue tool. This tool travels an entire span of energized or non-energized ACSR conductor to infer a conductor's tensile strength by magnetically sensing the remaining cross-sectional area of its steel core wires. LineVue is non-destructive and allows for a greater number of condition assessments per year and is more cost effective when compared to physically removing conductor samples for laboratory testing. LineVue also provides a surface inspection assessment of the extent and severity of corrosion.

Laboratory Testing

Laboratory testing can be performed on all conductor types. There are two types of laboratory testing: short conductor sample testing and long conductor sample testing. Short conductor sample testing involves dissecting a five meter conductor sample into its strands and laboratory testing these strands for the following factors: extent and severity of rust, remaining zinc, torsional ductility, and tensile strength.

Long conductor sample testing involves taking a sample from ahead of the suspension clamp to a point past the mid-span point. The total length of the sample, depending on the span length, is typically between 100 and 200 metres. Long conductor sample testing examines everything outlined in the above short conductor test, with the addition of the following whole conductor tests:

i. Aeolian Vibration Endurance Test
ii. Sheave Test as per IEEE Std. 1138-1994
iii. Breaking Load Test

LineVue scans and short sample testing provide a primary assessment of a line's condition and in most cases, is sufficient to categorize a conductor as being in good, fair or poor condition, and determine whether replacement is required. Conductors conclusively not in poor condition will be scheduled for a follow-up assessment in 5 to 15 years depending on the level of deterioration recorded in the initial testing. Where signs of concerning deterioration are found but poor condition cannot be clearly established based on test results, a more comprehensive assessment through a long conductor sample test is performed to ensure only confirmed poor condition conductors are targeted for replacement. In this regard, long sample tests can uniquely provide confirmatory information, including a view on estimated remaining life of a conductor. Only the long sample conductor test can provide an estimate on remaining life. Therefore, this tool can be useful for objectively prioritizing work. However, a long conductor sample is operationally more difficult to perform, much more expensive to test, and takes many months to complete.

2.2.4.1.5.2 ASSET REPLACEMENT AND RENEWAL

When condition assessment results conclude that a conductor is in poor condition, a line renewal project is planned and scheduled, taking into account the condition as well as the consequences of failure to the system and connected customers.

Line renewal projects incorporate the replacement of all deteriorated components within the targeted line section, including structures, structure members, shieldwire, and insulators. Components that are in good condition are not refurbished or replaced during

this time. Given that the conductor has the longest ESL among transmission line assets, bundling conductor replacement with the replacement of other components is cost effective for sustaining an overhead power line. In general, when the conductor requires replacement, it is common for other line components to have also deteriorated to poor condition and require replacement or renewal as well. The deployment and mobilization cost for crews to perform line work is significant, and as such performing multiple tasks in a coordinated fashion materially reduces costs and time when compared to performing sustainment work piecemeal on an asset-by-asset basis.

As the population of deteriorated conductors continues to increase (currently at 30% of the fleet or 8,375 circuit-km), so does the risk to public safety and reliability. Not addressing these increasing risks endangers the public and exposes Hydro One to a scenario in which the next weather event could result in the failure of a significant number of Hydro One's conductors, requiring finite resources to restore an overwhelming number of circuits at once. It is prudent for Hydro One to proactively address the conductors in poor condition to ensure the population of deteriorated conductors is maintained at manageable levels, thereby managing the risks to safety and reliability.

2.2.4.2 UNDERGROUND CABLES

2.2.4.2.1 ASSET DESCRIPTION / PURPOSE

Underground transmission cable systems are used to transmit high voltage electricity below ground in areas where overhead lines are unsafe, not feasible, impractical or undesirable. They are typically installed beneath public roadways in densely populated urban centres connecting portions of the overhead network, generators and substations.

Underground cable systems consist of the high voltage power cables and ancillary components such as terminations and pumping plants used to support their operation. Hydro One uses the following cable types:

- Low-Pressure Liquid-Filled (LPLF)
- High-Pressure Liquid-Filled (HPLF)
- Extruded Cross-linked Polyethylene (XLPE)

LPLF and HPLF cables use paper impregnated with dielectric fluid (oil) as the insulation medium while XLPE cables utilize oil-free solid polyethylene material. Figure 22 and Figure 23 illustrate various cable installations.

Figure 22: LPLF or XLPE Direct Buried Cables

Figure 23: XLPE or LPLF Cable Concrete Duct Bank

2.2.4.2.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.4.2.3 ASSET DEMOGRAPHICS

Hydro One operates approximately 279 circuit km of in-service high voltage underground transmission cables at either 115 kV or 230 kV. The majority of the underground transmission system are oil-filled LPLF and HPLF cables, with the balance comprising of XLPE cables. HOSSM does not have any high voltage underground cables.

Hydro One's underground cable fleet has an average age of 41 years with an ESL of 70 years for LPLF and HPLF cables, and 50 years for XLPE cables. A demographic summary of the cable population is shown in Table 32. As discussed below, replacement investment decisions are made based on condition assessments, not age or ESL.

Table 32 - Underground Cable Demographics

Type	Quantity (cct km)	Portion of Fleet by Type	Average Age (Years)	ESL (Years)	Beyond ESL (km)
LPLF	55	20%	58	70	0
HPLF	171	61%	45	70	0
XLPE	53	19%	10	50	0
Total	**279**	**100%**	**-**	**-**	**0**

2.2.4.2.4 ASSET CONDITION

Cable condition is based on a variety of quantitative test factors applicable to cable type. Routine condition assessment and more intrusive diagnostic tests have shown that 92% of underground cables are in good or fair condition and therefore have a low risk profile. This is due to rigorous maintenance programs and operational practices such as operating cables below their maximum thermal rating and insulating select 115 kV cables to 230 kV. Cables in poor condition, 8% of the population, are either planned for replacement or are being closely monitored for continued degradation. Figure 24 illustrates the breakdown of cable condition.

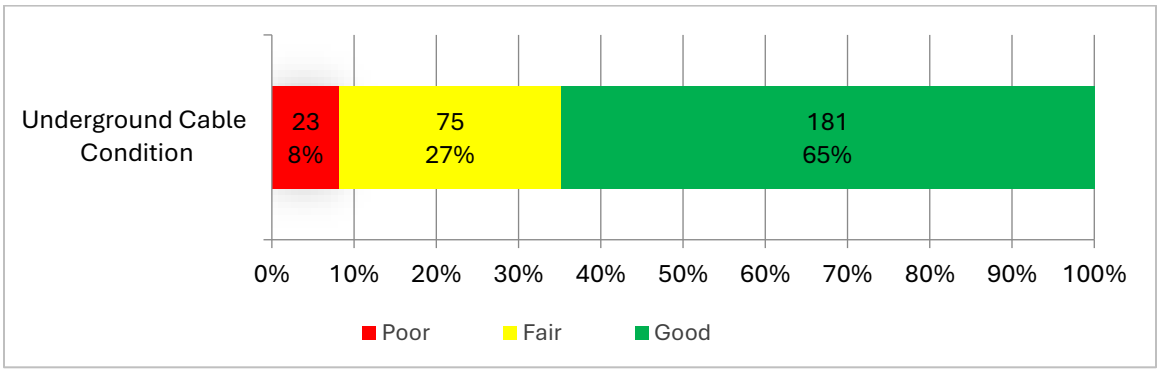

Figure 24: Underground Cable Condition

The majority of Hydro One's underground transmission system, 81% of the population, are LPLF and HPLF oil-filled cables. These cable types present an environmental risk in the event of a LPLF jacket and sheath, or HPLF pipe failure. Failures are not only caused by degraded components but also from dig-ins by unauthorized excavation activities since cables are often located beneath public roadways. When failures occur, significant volumes of oil may be released into the surrounding environment, necessitating extensive

cleanup and remediation efforts. Figure 25, Figure 26 and Figure 27 illustrate several historical oil-filled cable system failures that resulted in substantial oil leaks. Each incident involved the discharge of hundreds of litres of oil, leading to considerable environmental impact and remediation. For example, in 2022, a failure on circuit C5E resulted in the release of approximately 1,200 L oil, contamination of Lake Ontario along the Toronto Harbourfront near Yonge Street and Queens Quay, and a 40 day circuit outage to facilitate repair and environmental remediation activities.

Figure 25: LPLF Cable Sheath Corrosion and Oil Leak, Circuit L16D, 2019

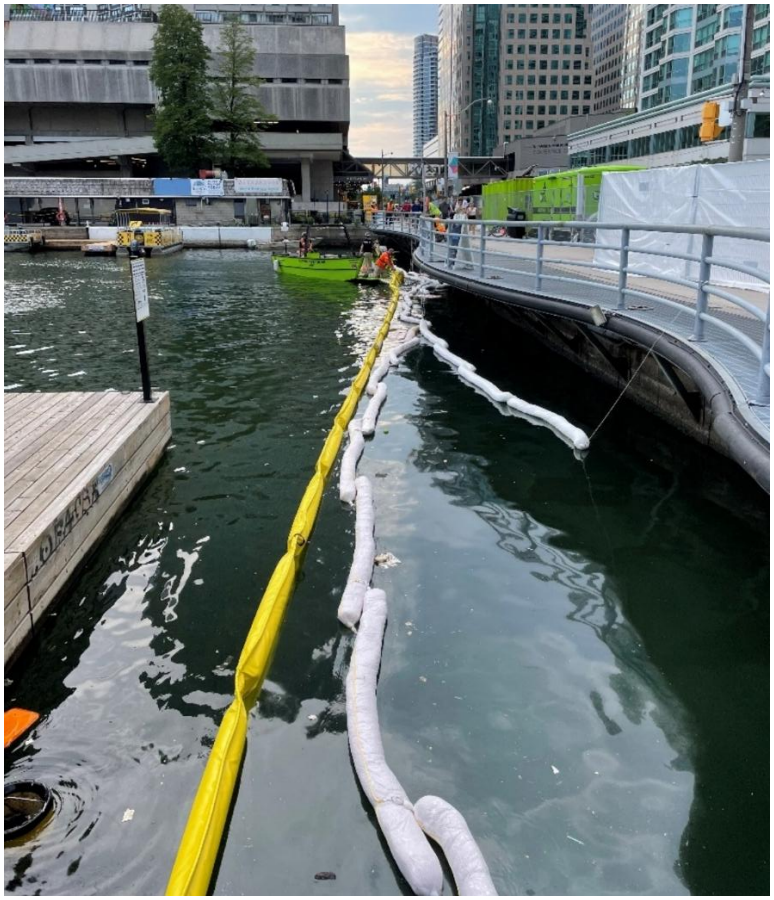

Figure 26: LPLF Cable Oil Leak into Lake Ontario, Circuit C5E, 2022

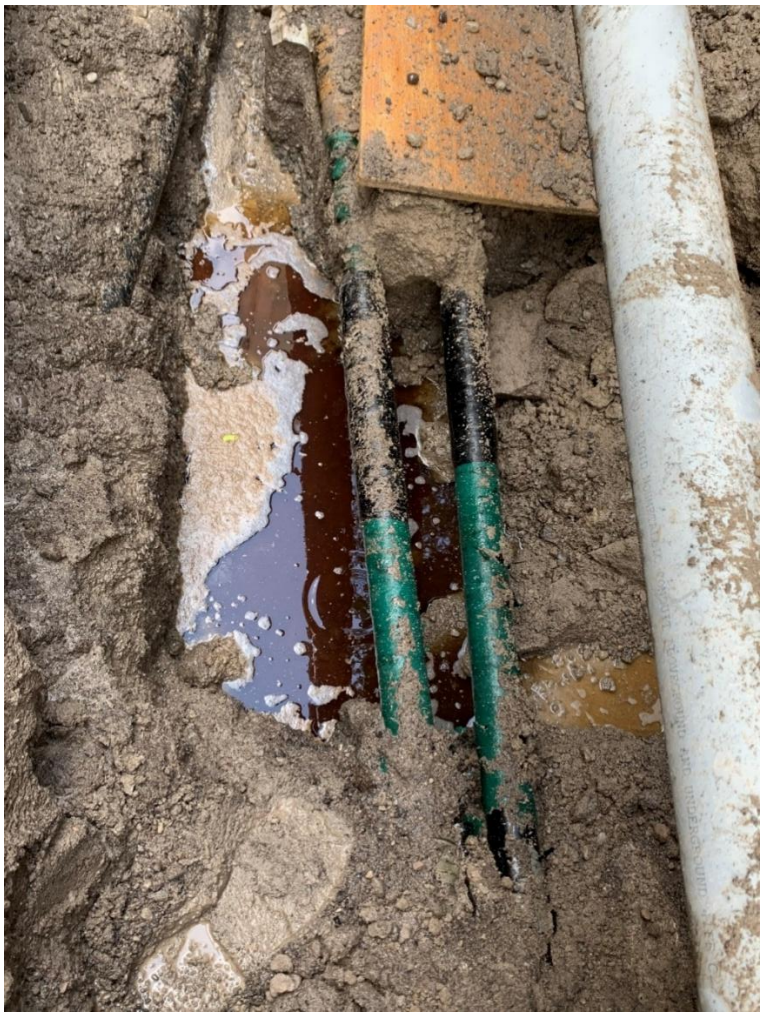

Figure 27: LPLF Cable Oil Leak, Circuit C7E, 2023

2.2.4.2.5 ASSET PERFORMANCE

Cable outages are infrequent and normally do not result in customer interruptions, since most customers are supplied by multiple circuits for redundancy and circuits are in a network configuration. However, a single supply may be insufficient to meet the customer's full demand. Hydro One's underground transmission system is predominantly located in densely populated urban centres, such as the Greater Toronto Area (GTA), Ottawa and Hamilton; and through Local Distribution Companies (LDCs) service a significant portion of load in those regions. Consequently, failures resulting in loss of supply or redundancy will negatively impact downstream LDC customers. Outages caused by underground cable failures are often lengthy in duration, with an approximate average

repair time of 43 days. For example, investigating, locating and repairing cable oil leaks requires substantial excavation and environmental remediation making restoration a time-consuming process with outages lasting weeks to months.

The frequency and duration of underground cable caused circuit outages are summarized in Figure 28 and Figure 29. Due to the small number of outages, it is not possible to infer a statistically significant performance trend.

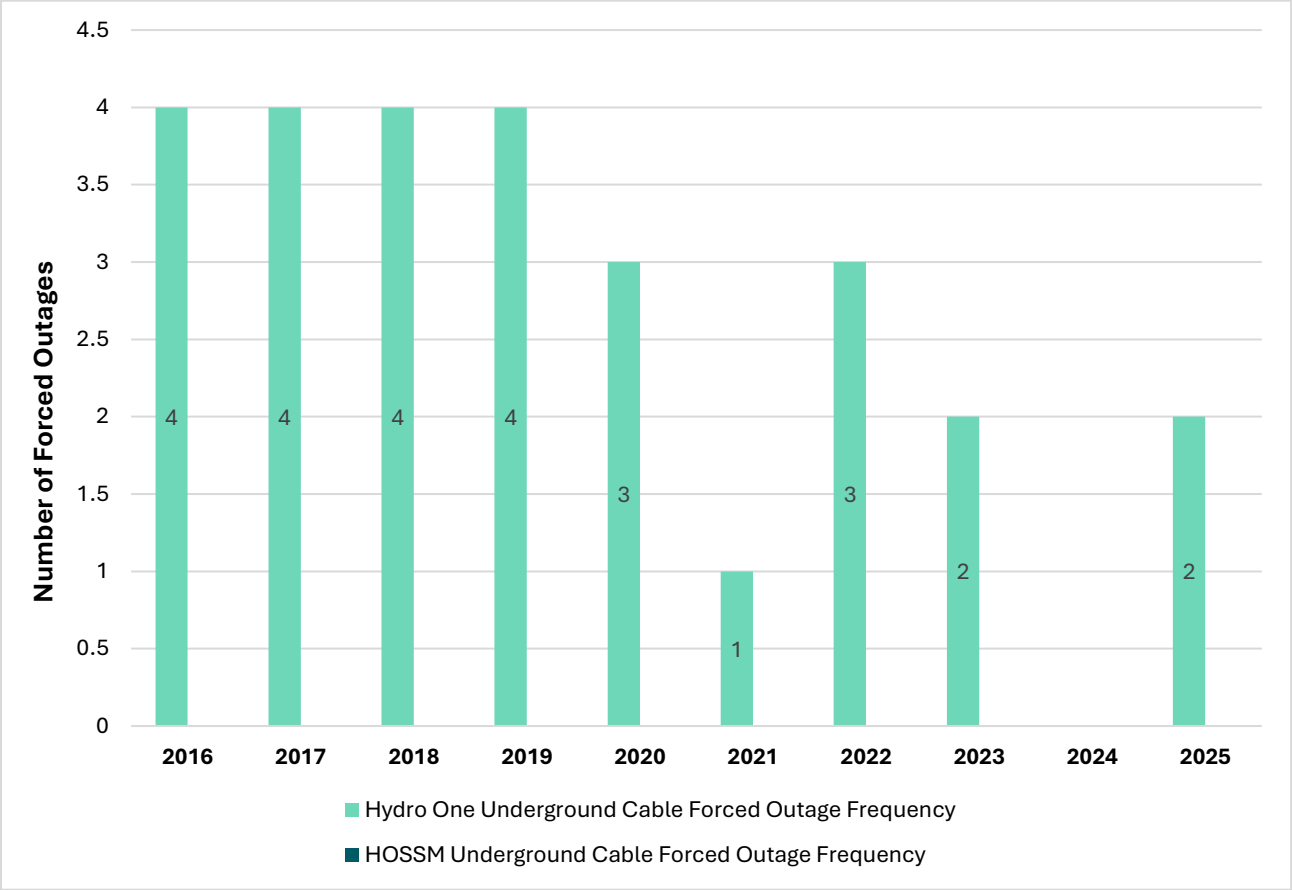

Figure 28: Underground Cable Forced Outage Frequency

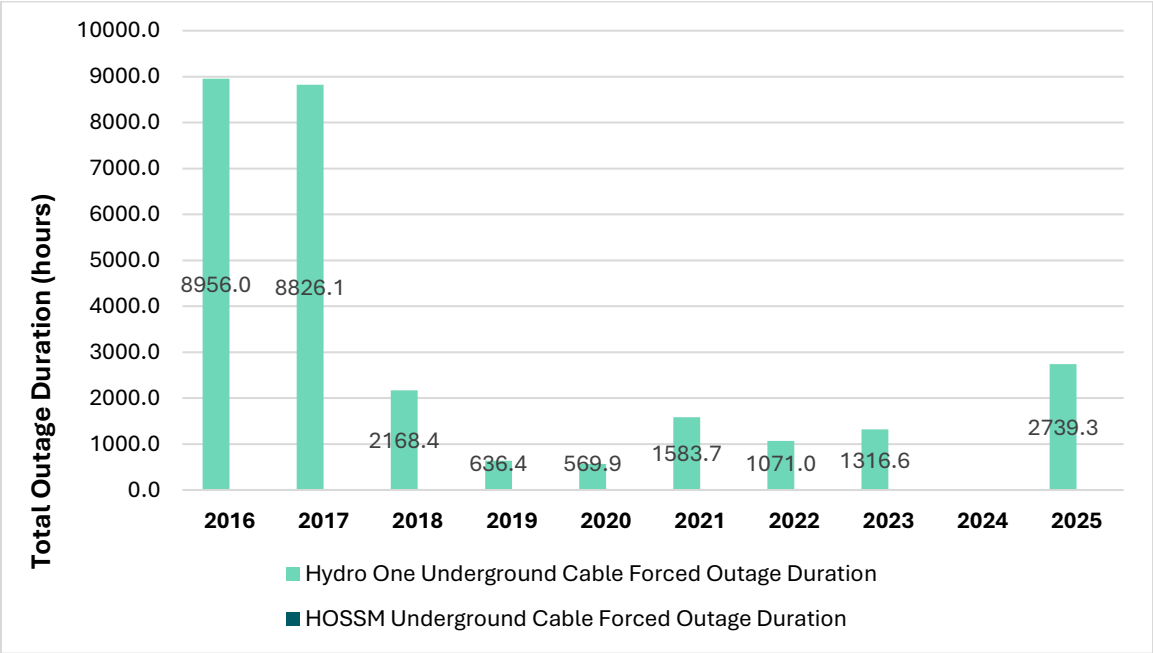

Figure 29: Underground Cable Forced Outage Duration

While the number of outages in 2016 and 2017 was not unusually high, the lengthy outage durations in those years were primarily the result of a splice failure on circuit H11L that allowed moisture to permeate the paper insulation, leading to cable failure. The repair time was significant due to material lead time and excavation required to access the cable.

2.2.4.2.6 ASSET LIFECYCLE

Hydro One's cable asset strategy is to maximize service life, while maintaining current risk levels, to minimize capital replacement expenditures. Given the potential for lengthy outages and the associated negative customer and environmental impacts of cable failures, the intent is to repair or replace underground system assets before unacceptable impacts to safety, customers, the environment or reliability materialize. This strategy involves performing rigorous condition assessments, prioritizing maintenance and repairs, and replacing poor condition cables when repairs are no longer practical. All repairs and replacements are driven by condition, not age or ESL, as determined through comprehensive condition assessments.

2.2.4.2.6.1 ASSET TESTING & MAINTENANCE PRACTICES

Maintenance programs are implemented to monitor cable condition and to identify and repair deteriorated components. Hydro One's cable maintenance programs include:

- preventive maintenance, comprising of condition assessment and testing activities;
- corrective maintenance, comprising of activities undertaken to investigate and repair equipment deficiencies; and
- cable locates, involve the legislative requirement to provide locate services of underground infrastructure.

These programs are discussed in detail in Exhibit E-02-02, Transmission Sustainment OM&A, Underground Cable Maintenance.

The majority of Hydro One's cable assets are in good condition, largely due to rigorous maintenance programs and operational practices. The fundamental objective of Hydro One's cable asset strategy is to maximize service life to minimize capital replacement expenditures. This is primarily achieved through a combination of preventive maintenance (condition assessment and testing) and corrective maintenance (repair) activities. Hydro One will perform comprehensive preventive maintenance, and perform critical planned and demand repairs. These efforts are intended to prevent a long-term increase in failures, oil leaks, and associated outages that could negatively impact both the environment and customers.

2.2.4.2.6.2 ASSET REPLACEMENT AND REFURBISHMENT

Hydro One will continue to replace poor condition cables and ancillary equipment that can no longer be practically maintained or repaired. For example, widespread jacket deterioration and sheath corrosion are the driving factors for LPLF cable replacement. For new construction and replacement projects, XLPE cables will continue to be used to eliminate the environmental and obsolescence concerns associated with oil-filled LPLF and HPLF cables.

There is an industry shift away from the use of LPLF and HPLF to XLPE cable systems. XLPE is currently the most widely used cable technology. As a result, manufacturers are

reducing production and support for oil-filled cable systems. LPLF and HPLF cables may be considered for special applications such as localized repairs and the relocation of short circuit lengths. To mitigate LPLF and HPLF cable obsolescence risks, Hydro One manages a spare inventory of cables and ancillary components.

Hydro One will continue to integrate distributed temperature sensing (DTS) systems for new and replacement cable installations where appropriate and feasible. Cable loading can change over time due to increased customer demand and external factors, leading to overheating and premature deterioration, thereby reducing cable useful life. DTS systems enable real-time temperature monitoring and thermal optimization to help maximize service life.

2.2.4.3 STRUCTURES & FOUNDATIONS

2.2.4.3.1 ASSET DESCRIPTION / PURPOSE

Steel Structures

Steel structures elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components. These structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 500 kV.

Wood Pole Structures

Wood poles structures serve the same purpose as steel structures. The majority of the wood pole structures are located in Northern Ontario, typically in remote locations with difficult access. Similar to steel structures, wood pole structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 230 kV.

Composite Structures

Composite structures refer to fiber reinforced polymer (FRP) structures. Hydro One began installing composite structures around 2010 as replacements for wood poles structures, particularly in areas prone to woodpecker damage. Composite structures offer several

advantages, including an extended service life of approximately 80 years and enhanced resistance to wildfires.

Foundations

Foundations support and anchor transmission structures to the ground and enable the structures to withstand their own weight, attached components and weather related external forces such as wind and ice. There are three dominant foundation types in Hydro One's transmission system: cast-in concrete footings, steel grillage footings, and steel anchors.

2.2.4.3.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.4.3.3 ASSET DEMOGRAPHICS

Steel Structures and Poles

Hydro One has approximately 49,200 lattice steel structures and approximately 1750 steel poles in its transmission system, whereas HOSSM has 12 lattice steel structures and 187 steel poles. Current steel structures have an average age of 65 years and an ESL of 80 years if they are not recoated. However, if recoated, the steel structures' service life can extend beyond the ESL. The demographics of the steel structure population of Hydro One and HOSSM are outlined in Table 33 and 34.

Table 33 - Hydro One – Steel Structure and Pole Demographics

Type	Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
Steel Towers in Light Corrosion Zones (C2 and C3)	10,400	67	80	2,600
Steel Towers in High to Very High Corrosion Zones (C4 and C5)	38,800	66	80	10,165
Steel Poles	1,750	44	80	0
Total	**50,950**	**-**	**-**	**12,765**

Table 34 - HOSSM – Steel Structure Demographics

Type	Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
Steel Towers in Light Corrosion Zones (C2 and C3)	12	57	80	0
Steel Poles	187	39	80	0
Total	**199**	**-**	**-**	**0**

Wood Pole Structures

Hydro One has approximately 38,550 wood pole structures in its transmission system and HOSSM has approximately 2,480. The average age of Hydro One's wood pole population is 36 years and approximately 11,270 of the wood poles are beyond their ESL of 50 years. The average age of HOSSM's wood poles 28 years and approximately 50 are beyond their ESL of 50 years. The demographics of the wood structures population of Hydro One and HOSSM are outlined in Table 35 and 36.

Table 35 - Hydro One – Wood Pole Structure Demographics

Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
38,550	36	50	11,270

Table 36 - HOSSM – Wood Pole Structure Demographics

Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
2,480	28	50	50

Composite Structures

Hydro One has approximately 1,670 composite structures in its transmission system and HOSSM has approximately 304. The average age of Hydro One's composite pole population is 5 years and none are beyond their ESL of 80 years. The average age of HOSSM's composite pole population is 18 years, and none are beyond their ESL of 80 years. The demographics of the composite structure populations of Hydro One and HOSSM are outlined in Table 37 and Table 38 .

Table 37 - Hydro One – Composite Structure Demographics

Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
1,670	5	80	0

Table 38 - HOSSM – Composite Structure Demographics

Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
304	18	80	0

Foundations

Hydro One's transmission system contains approximately 49,200 steel lattice structures with foundations made of either concrete or steel. Approximately 32,500 foundations are steel grillage and the other 16,700 foundations are cast in concrete (auger or pad and pier). Hydro One began using concrete auger type foundation in 1970s because it allows for construction efficiency and asset durability. It is also compliant with more restrictive environmental protection regulations. There are total of 12 lattice structures in HOSSM system and all are with grillage footing. The demographics of the steel lattice structure foundations are outlined in Table 39 and Table 40:

Table 39 - Hydro One Foundation Demographics

Type	Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
Cast-in Concrete Footings	16,700	41	100+	0
Steel Grillage Footings	32,500	82	80	12,800
Total	**49,200**			**12,800**

Table 40 - HOSSM Foundation Demographics

Type	Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
Steel Grillage Footings	12	57	80	0
Total	**12**			**0**

2.2.4.3.4 ASSET CONDITION

Steel Structures

Steel structures corrode overtime. The service life of a steel structure primarily depends on the condition of its Hot Dip Galvanizing (HDG) coating. Once this protective zinc layer is lost, the structure's carbon steel is exposed and the corrosion rate could increase by a factor of eight to ten. This will result in the loss of structural strength, ultimately requiring replacement.

Consistent with ISO 9223:2012, the province of Ontario is divided into four corrosion zones ranging from C2 to C5. Each of these corrosion zones has a range of corrosion rates which can be used to estimate the service life of HDG steel based on its location. C2 and C3 zones are defined as light corrosion zones and the structures in these zones will be protected and maintained in good condition for over 100 years without requiring any recoating. C4 and C5 zones are defined as heavy corrosion zones which have high and very high corrosion rates. Structures in these zones will lose the protective HDG coating much earlier, potentially losing the entire HDG coating after 45 years. Approximately 38,800 steel lattice structures are located within Southern Ontario which composes of C4 and C5 zones. Approximately 10,700 of the steel structures in C4 and C5 zones are in fair to poor condition, reflecting that the steel structure has corrosion on the HDG and on the bare steel layer. These structures would require recoating to extend their service life.

In 2018, Hydro one discovered that around 7,000 of its 230 kV towers are prone to experiencing middle arm hanger vibration and fatigue causing cracks. These cracks could lead to complete arm failure, damaging the bottom arm and dropping conductors to the ground. Such failures pose serious reliability and safety risks to Hydro One's customers, employees and the public, and cannot be left unresolved. To mitigate these risks, the identified structures require refurbishment (hanger replacements and/or addition of braces to the top face of the middle arm). Approximately 5,500 towers have either previously been fixed or will be as part of refurbishment projects, and about 1,500 towers are still in need of repair. During the decades of patrol and inspection, Hydro One also found approximately 1200 towers with defected members that could cause potential structural failure, repair or replacement of these damaged members is required to maintain the

structure integrity. Figures 30 and 31 provide examples of damaged steel structure members identified through these inspections.

Figure 30: Damaged Steel Structure Members, Circuit H27H, 2025

Figure 31: Damaged Tower Members, Circuit T22C, 2025

Wood Pole Structures

Wood structures deteriorate over time. The rate of deterioration depends on many factors including location, weather, wood species, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same geographical area. Due to the nature of the design, the old design of wood cross-arm tends to be the weak link and is typically the primary cause of failure. Figures 32 to 34 provide examples of failed and deteriorated wood pole structures.

Figure 32: Failed Wood Pole, Circuit S2N

Figure 33: Failed Wood Pole, Circuit P4S

Figure 34: Rotten Wood Pole Base, Circuit S2B

Based on the most recent wood pole structure condition data obtained through field inspection, approximately 7,741 wood pole structures (including approximately 296 from HOSSM), corresponding to approximately 19% of the population, are in poor condition, as illustrated in Figure 35 and Figure 36. These poor-condition wood pole structures typically exhibit rotting on the cross-arm or pole, woodpecker damage or mechanical damage. Approximately 21% (8,776 structures) of the wood pole population needs to be assessed to determine its condition, while about 59% (24,509 structures) of the population is either in good condition or not eligible for assessment (i.e. younger than 25 years).

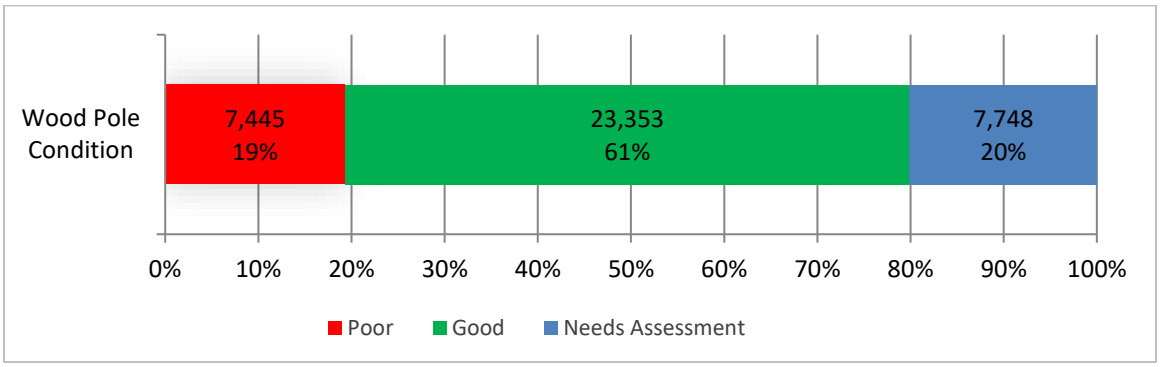

Figure 35: Hydro One – Wood Pole Condition

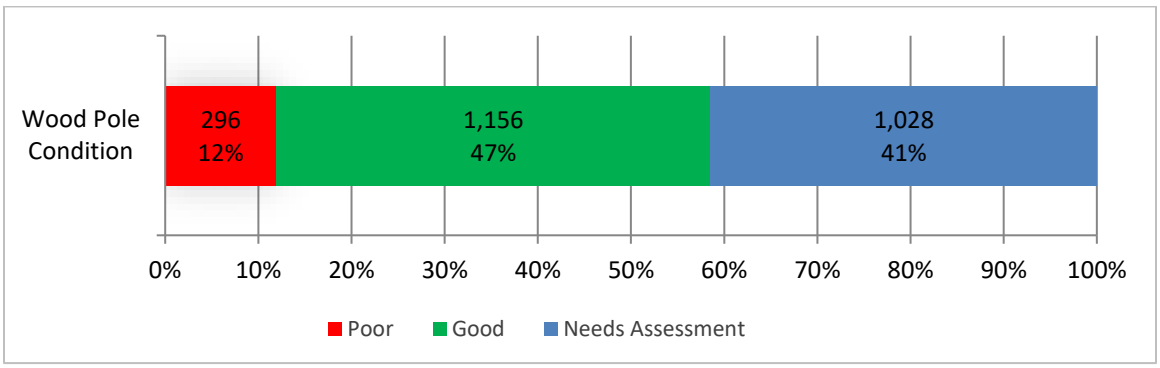

Figure 36: HOSSM – Wood Pole Condition

<u>Foundations</u>

Hydro One is currently focusing on grillage footings and anchors, which due to their age and material sustain a higher incidence of corrosion. Concrete footings are younger and are not displaying signs of corrosion. From the early 1900s into the 1960s, most lattice steel structures were constructed with a grillage (buried steel) foundation. On Hydro One's transmission system, approximately 32,500 grillage footings include about 3,640 guyed structures which rely on the integrity of the steel grillage and anchors for support. Steel tower grillage foundations and anchors are fabricated with a zinc-based galvanized coating which protects the underlying steel against corrosion. Coating life can vary considerably depending on the surrounding environment. Once the galvanized coating has been depleted, the underlying bare steel begins to corrode, typically much faster than with the galvanized coating. The accelerated corrosion results in metal loss which reduces the mechanical strength of the grillage foundation.

When a steel grillage footing foundation reaches 50 years old, it will need to be assessed and/or require corrective action to extend its service life due to a greater propensity for degradation. There are approximately 19,100 structures with grillage foundations that have not been assessed. The condition of these grillage foundations cannot be determined until detailed below grade inspection is performed.

2.2.4.3.5 ASSET PERFORMANCE

Steel Structures

Forced outages for steel structures represent the number of outages caused by a steel structure failure such as complete tower collapse or a broken (or bent) tower member. It does not include forced outages resulting from weather conditions or external factors, such as transmission lines being damaged by tornadoes, vehicles, or similar impacts. Figure 37 and Figure 38 below illustrate the frequency and duration of forced outages due to steel structure failures. HOSSM has experienced no steel structure related outages. Note that the frequency and duration of forced outages do not drive tower coating investment decisions. The main driver for the tower coating program is based on capital cost avoidance as opposed to reliability and safety risk mitigation. Tower Coating extends the steel structure service life and hence minimizes higher future capital expenditures due to costly steel member or complete structure replacement.

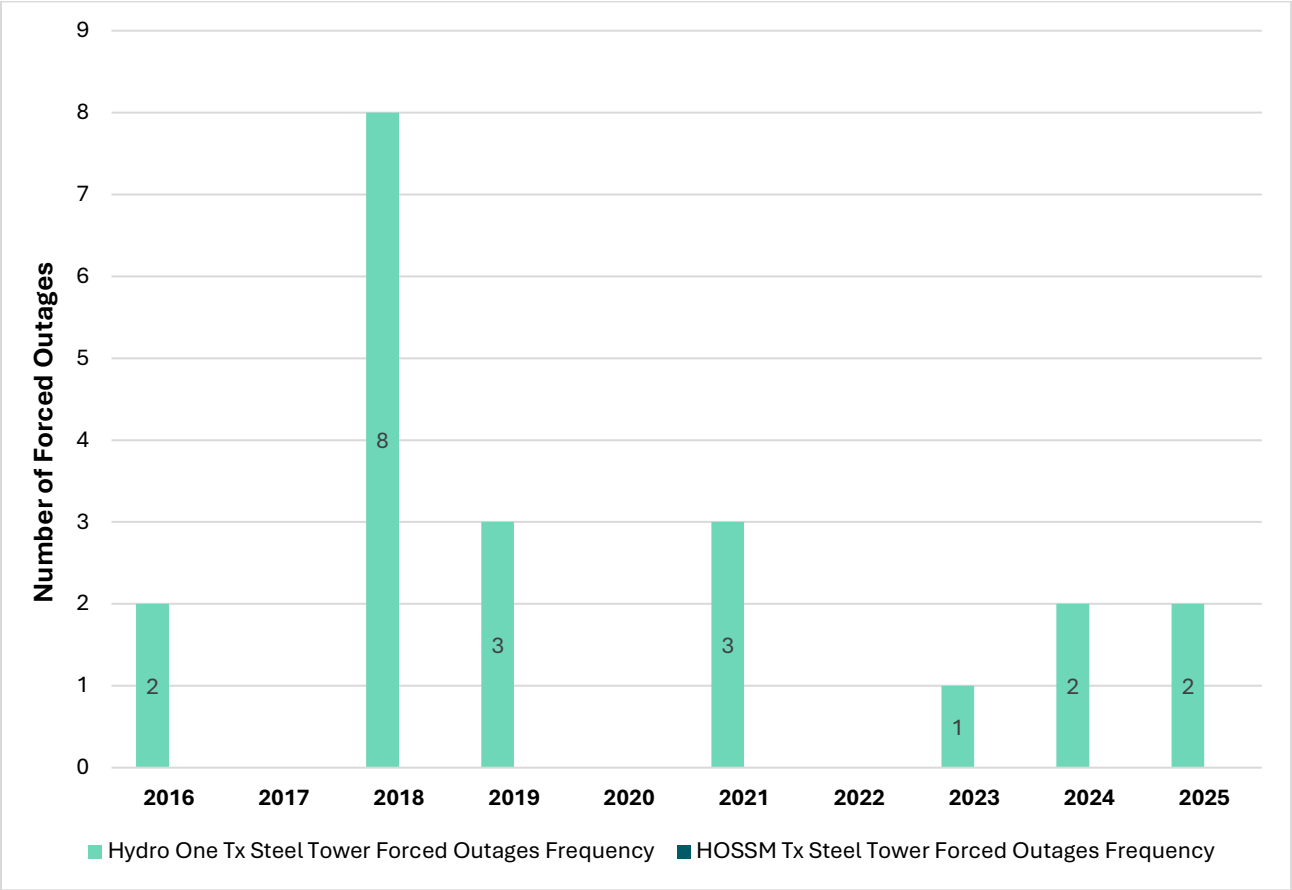

Figure 37: Steel Structure Forced Outage Frequency

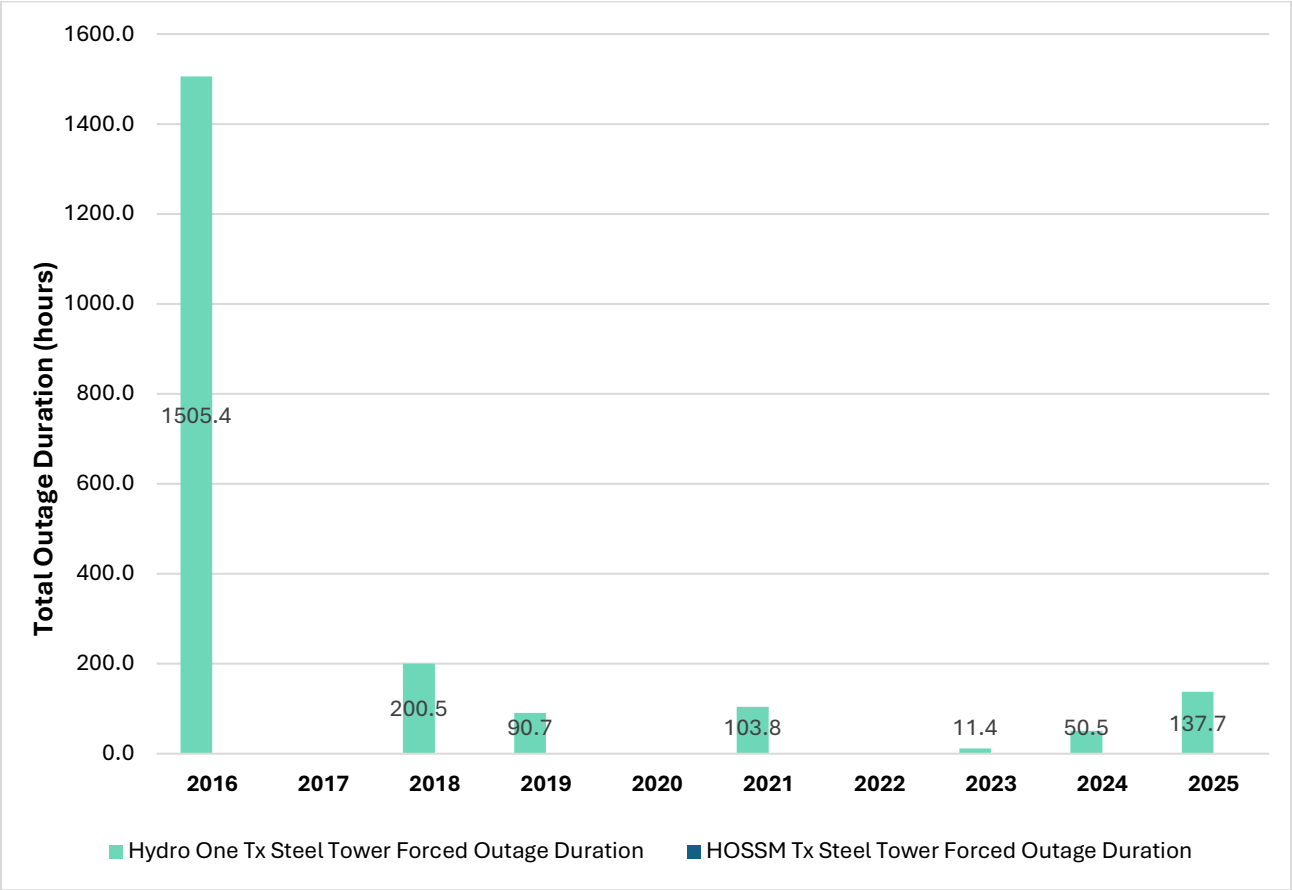

Figure 38: Steel Structure Forced Outage Duration

Wood Pole Structures

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result, a wood pole or cross-arm failure can often directly result in a customer outage. Many of these northern wood pole circuits feed major industrial customers. Without an adequate supply of power, these customers may be forced to shut down until power is restored. Such an event can add significant cost to a customer's operations. Note that the frequency and duration of forced outages do not drive wood pole replacement investment decisions. Such performance metrics are considered lagging indicators of asset health, meaning the asset has already deteriorated significantly by the time failure occurs. Instead, Hydro One takes a proactive, risk-based approach by replacing wood pole structures in poor condition. This strategy helps reduce both safety and reliability risks.

The forced outage frequency and duration are shown in Figure 39 and Figure 40, respectively. Hydro One will continue to monitor the condition of its wood pole fleet and implement the necessary steps to mitigate any emerging trends. HOSSM has experienced few outages attributable to wood pole structures.

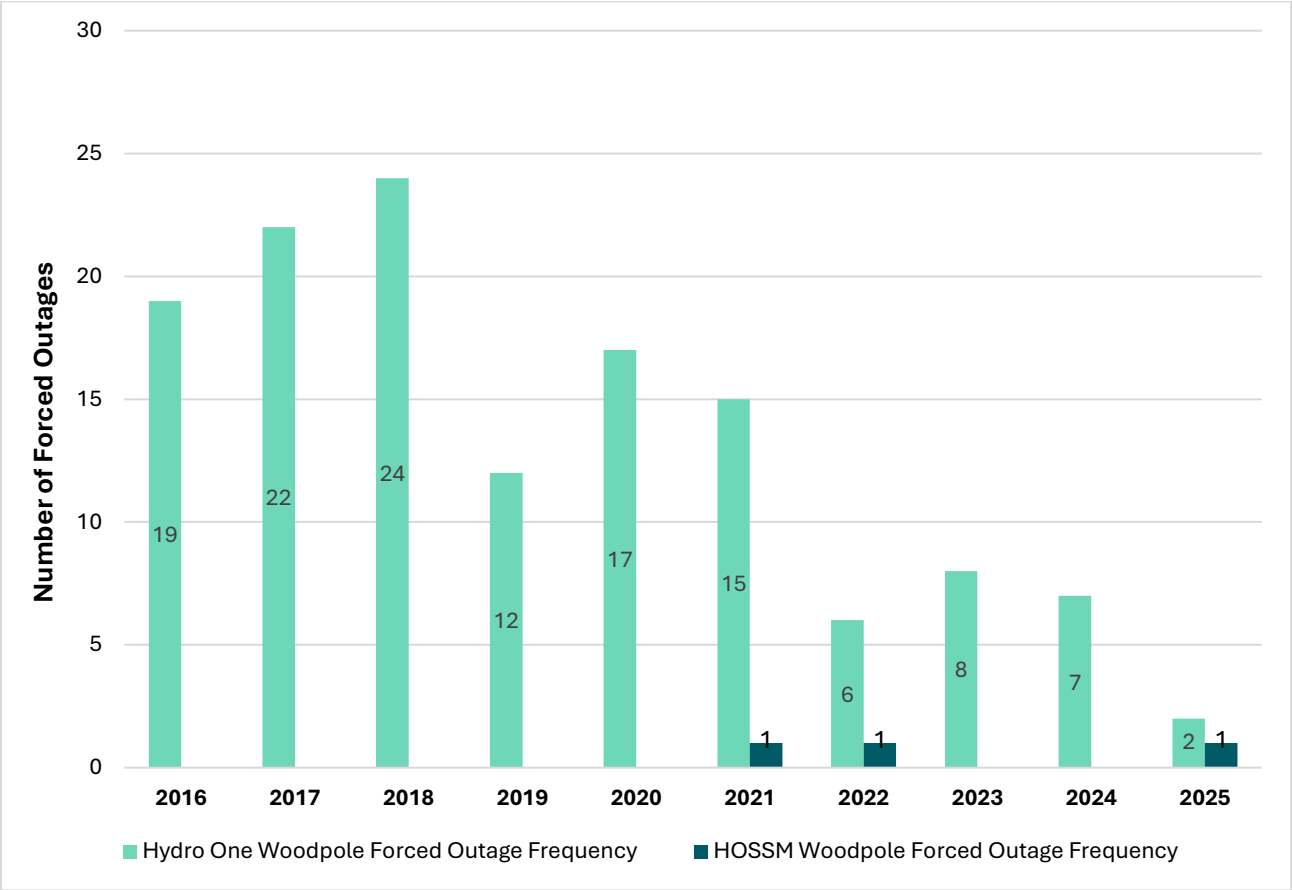

Figure 39: Wood Pole Forced Outage Frequency

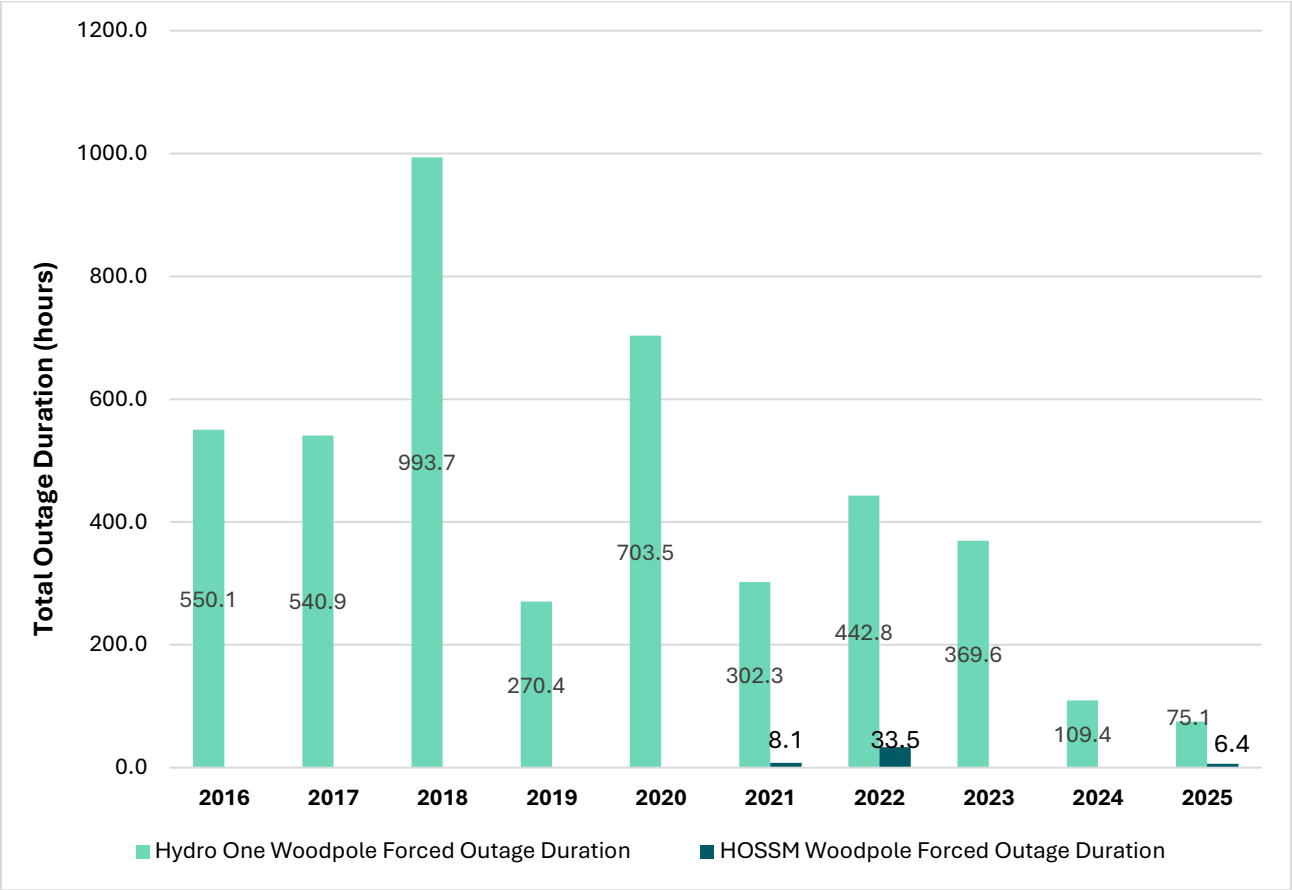

Figure 40: Wood Pole Forced Outage Duration

2.2.4.3.6 ASSET LIFECYCLE

Steel Structures

Hydro One's strategy for steel structures is to manage the fleet through a combination of planned structure replacements, component refurbishments and tower coating in order to maintain the reliability of the system and decrease life cycle costs. Structure replacements and component refurbishments are usually part of bundled line refurbishment work.

Wood Poles

Hydro One's strategy for wood poles is to proactively replace wood poles in poor condition in order to reduce failures that impact customer reliability and to minimize emergency response activities. Hydro One continues to use a condition-based asset management strategy to manage the wood pole fleet.

Foundations

Hydro One's strategy for transmission structure foundations is mainly focused on repairing or replacing steel grillage footings and steel anchors, which are directly buried into the ground.

2.2.4.3.6.1 TESTING & MAINTENANCE PRACTICES

Steel Structures

The condition of steel structures is determined through ground and aerial patrols, and detailed ground level condition assessments. Towers are visually rated based on field guides[15] that have been developed in accordance with standards set by the Society for Protective Coatings. The assessment determines whether tower refurbishment and/or coating are necessary.

Wood Poles

Hydro One utilizes a condition-based inspection approach to manage its wood pole structure population. A combination of aerial and ground level assessment is performed to assess various aspects of the structure including but not limited to: pole top condition, cross arm condition, shell thickness, woodpecker damage etc. The assessment results are evaluated in accordance with Hydro One guidelines to identify poor condition wood poles that warrant replacement.

Foundations

Tower foundations are assessed through the Transmission Lines Foundation Clean, Coat and Assess Program and refurbishment projects. There are very few cases where concrete foundation deteriorations have occurred in Hydro One's system. As a result, current Hydro One programs related to foundations focus on steel grillages and steel anchors installed before 1970. These steel footings are at least 50 years old and recent inspection results have shown a higher incidence of degradation.

[15] Field guides are tools that crews can use to decide how to rate the condition of a tower. The guides provide pictures and descriptions associated with certain rust levels and help to standardize the ratings between different crew members performing the assessment.

2.2.4.3.6.2 ASSET REPLACEMENT AND REFURBISHMENT

Steel Structures

If steel structures are not recoated prior to an acceptable extent of strength loss (i.e. typically, before reaching 10% thickness loss), the opportunity for re-coating would be missed altogether and the towers will ultimately have to be replaced or heavily refurbished at a significantly higher cost. Based on Hydro One's assessment and experience, tower coating is the most economic and efficient method of prolonging the service life of steel structures.

Hydro One will continue to focus on recoating towers in Southern Ontario, which comprises zones C4 and C5. By recoating structures that have experienced less than 10% steel loss, the service life of the structures can be extended, thereby minimizing lifecycle costs. The main driver for the tower coating program is economic savings, as opposed to reliability and safety risk mitigation. Based on prior analysis, net present value calculations show significant savings from tower coating compared with tower replacement. With regard to the 230 kV structure types experiencing middle-arm hanger fatigue, Hydro One has developed a new design to install additional bracing to prevent further arm hanger fatigue, which could ultimately lead to mechanical failure. Hydro One has been installing the additional bracing on impacted structure types since 2019 and will continue such repairs until all affected structures are refurbished. For towers with defective members, Hydro One will continue to refurbish them and restore their structural integrity.

Wood Poles

Hydro One will continue to proactively replace poor condition wood structures identified from both aerial and ground patrols and condition assessments. Delaying these replacements increases the risk of failures, which poses reliability and safety risk and shift expenditures to the more costly demand emergency replacement program. Hydro One will continue to refine its data collection process related to the structure replacement and line refurbishment programs, thereby permitting an accurate depiction of the network inventory in order to improve decision making.

Foundations

Hydro One will continue to prioritize all grillage foundations for Clean, Coat and Assess based on the factors such as circuit voltage, criticality of the circuit and customer impact. Based on the corrosion severity of steel structures identified through the Clean, Coat and Assess Program, the foundations are either cleaned and coated to re-establish the layer of protection or scheduled for future repairs or replacements. The Foundation Life Extension Program is used to complete repairs or replacements of foundations identified through the previous program.

2.2.4.4 INSULATORS

2.2.4.4.1 ASSET DESCRIPTION / PURPOSE

As an integral component of the transmission system, transmission line insulators are required to provide two essential functions: mechanical support for overhead conductors and electrical isolation between the energized conductors they support and the grounded towers to which they are attached. A typical transmission line insulator is shown in Figure 41. Insulator classifications are summarized in Table 41.

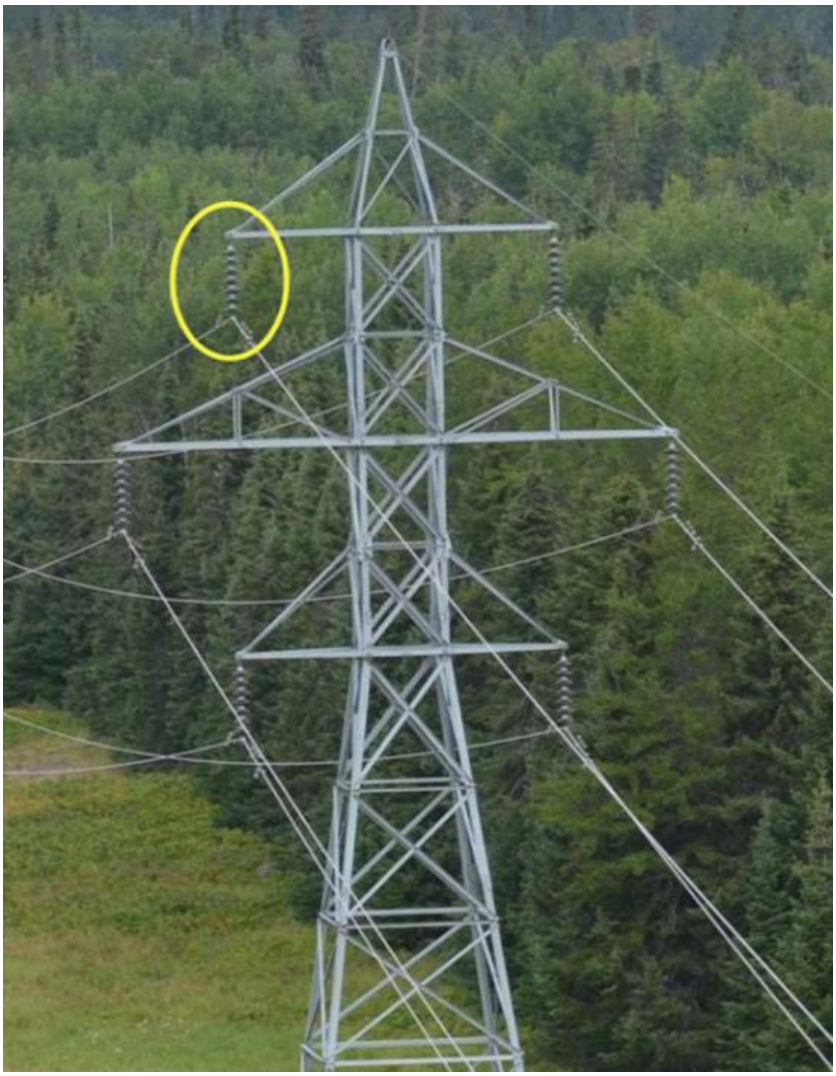

Figure 41: Transmission Line Insulator String

Table 41 - Insulator Material Classifications

Type	Example	Vintage	Voltage (kV)	Description
Porcelain		1910+	115, 230, 500	Porcelain insulators are the oldest and most common insulator type used by Hydro One. They are projected to last for the life of the line; however, isolated failures do occur and there are known issues affecting specific vintages.
Glass		Mid-1980s+	115, 230, 500	Hydro One began installing glass insulators in the mid-1980s as an alternative to defective porcelain. They are projected to last for the life of the line; however, isolated failures do occur.
Polymer		Mid-1980s+	115, 230	Polymer insulators were developed as an alternative to porcelain and glass. They are projected to last 30 years; however, failures do occur and there are issues affecting specific vintages and configurations.

2.2.4.4.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.4.4.3 ASSET DEMOGRAPHICS

There are approximately 489,000 insulator strings on approximately 124,414 circuit structures in Hydro One's and HOSSM's overhead transmission network. The insulator demographics by material type are shown in Table 42.

Table 42 - Hydro One and HOSSM – Insulator Demographics

Type	Hydro One Quantity (Circuit Structures)	HOSSM Quantity (Circuit Structures)
Porcelain	60,233	2,126
Glass	51,134	449
Polymer	10,051	421
Total	**121,418**	**2,996**

Demographics are not a driving factor for the replacement of porcelain or glass insulators since quality insulators are generally expected to last for the life of the transmission line and significant condition degradation is not expected to occur over time. Replacement is normally done as part of other work programs (e.g. line refurbishment). Program specific insulator replacement work targets strings that have prematurely degraded due to one-off failures (e.g. broken shells), manufacturing defects, improper functionality or poor design.

Hydro One uses polymer insulators on the 115 kV and 230 kV transmission systems. Polymer insulators have an ESL of 30 years and, due to their material properties, degrade with age. First-generation polymers installed in the mid-1980s are beyond their ESL and will need to be replaced. First-generation polymers are more problematic compared to more recent generations. When older polymer insulators were designed and manufactured, the long-term effects of electric fields were not well understood which caused unexpected polymer degradation. Newer generations use modified designs and refined manufacturing techniques.

2.2.4.4.4 ASSET CONDITION

Quality porcelain and glass insulators have low failure rates and are expected to last the life of the transmission line. However, porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1950 and 1982 suffer from a phenomenon known as cement expansion or cement growth. The expansion of cement (which bonds the pin to the porcelain) creates radial cracks in the cement and porcelain shell resulting in two possible failure modes:

- Mechanical Failure: where the pin separates from the porcelain causing a conductor drop; and/or
- Electrical Failure: where the cracked porcelain reduces insulating properties.

The cement growth phenomenon is illustrated in Figure 42 and Figure 43. Cracks in the cement and porcelain shell are not readily visible or easily detectable. Insulators suffering from cement expansion are at risk of failing prematurely and unpredictably depending on mechanical load and environmental conditions.

Figure 42: Porcelain Insulator Unit Exhibiting Cement Expansion

Figure 43: Porcelain Insulator Unit Exhibiting Cement Expansion

To address concerns associated with defective porcelain insulators, Hydro One retained a third-party expert, EPRI, to perform laboratory testing on COB and CP porcelain insulators in 2016 and 2017 in order to assess their condition. The purpose of the study was to assist Hydro One in determining the pacing of porcelain insulator replacement.

Phase one of the EPRI study was completed in 2016 and included testing of 299 insulators. The results of this study supported the timely replacement of COB and CP insulators manufactured between 1965 and 1982. Phase two of the testing was performed on 591 insulators in 2017 to supplement phase one findings and to provide data on the deterioration rate of the insulator population. The results of the analysis showed:

- a large number of the tested insulators exhibited porcelain cracking after mechanical and electrical testing;
- the propensity for the insulators to puncture (crack) during thermal mechanical cycling (TMC);

- the insulators are highly susceptible to electrical puncture under steep transient voltages (e.g. lightning);
- TMC drastically decreases the already weak ability of the insulators to withstand electrical puncture; and
- a significant number of insulators separated mechanically during TMC.

These results suggest that the number of in-service punctured units will increase as the insulators experience significant mechanical loading events. If a string contains mechanically compromised units, the insulators will fail if the maximum applied load exceeds the units' remaining mechanical strength. The majority of conductor drops recently experienced on Hydro One's porcelain insulated transmission system have punctured insulators.

The two-phase analyses provided overwhelming evidence supporting replacement of defective porcelain insulators to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation from EPRI is to remove the identified COB and CP insulators from service as soon as practically possible.

EPRI testing of pre 1965 insulators during the original Phase One study initially suggested that some 1950s units performed satisfactorily, while insulators manufactured in 1960 and later showed poor results. Based on this, Hydro One previously set the replacement range to 1960–1982 to target known defective COB/CP insulators.

Subsequent evidence showed this range was too narrow. Recent failures involving insulators manufactured in 1950, 1953, 1956, 1958, 1962, and 1963 indicate that earlier vintages are also at risk. Additionally, the earlier assessment relied on limited EPRI 2016 testing of 11 kip 1950 units. A later EPRI 2017 study tested 15 kip insulators from 1952 and 1963 and found their performance comparable to 1970s units, demonstrating that the earlier assumption of acceptable 1950s performance did not represent the broader population, as most Hydro One insulators are 15 kip units.

Considering both the expanded EPRI testing and observed field failures, Hydro One has extended the replacement range to all insulators manufactured from 1950 through 1982, ensuring the removal of all potentially defective COB/CP units from the transmission system.

The porcelain insulators manufactured by CP and COB are used province-wide in Hydro One's transmission system. When Hydro One started its program to remove defective COB and CP insulators, there were approximately 50,000 circuit structures with defective porcelain insulators. To date, approximately 31,300 circuit structures have had their COB and/or CP insulators replaced. A breakdown of the defective population in relation to the total insulator population as of 2025 year-end is shown in Figure 44 and Figure 45.

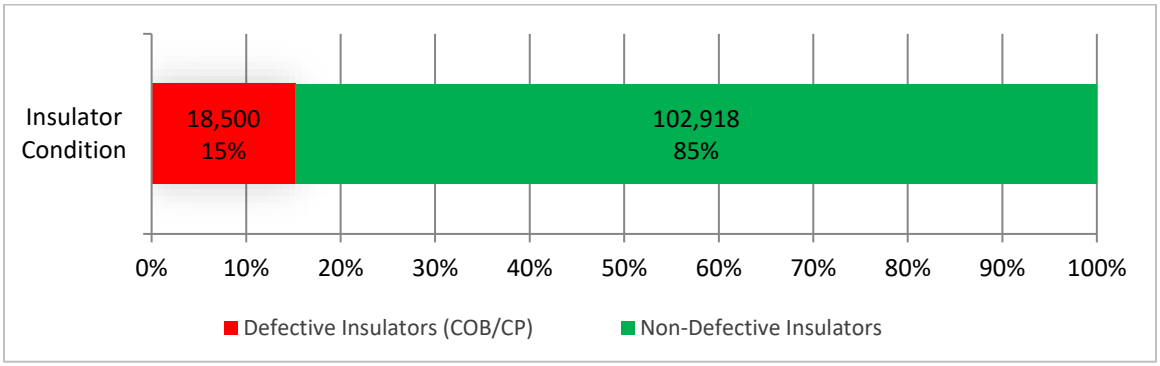

Figure 44: Hydro One Insulator Condition

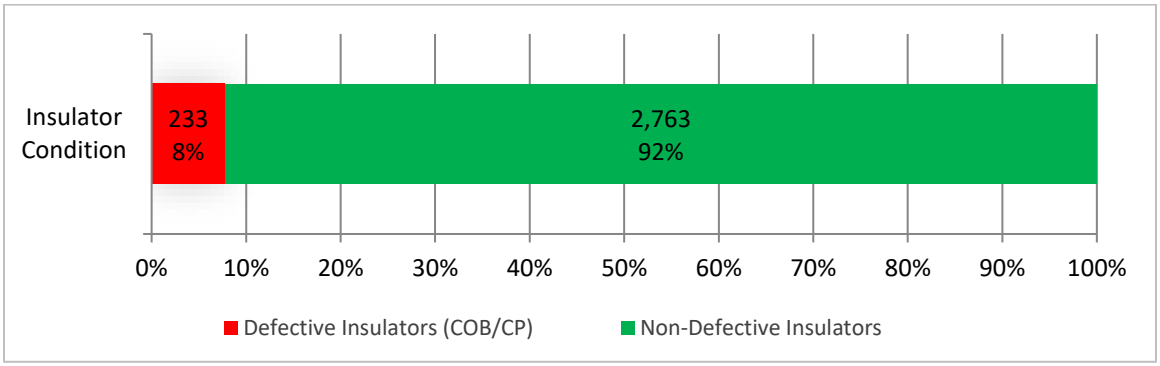

Figure 45: HOSSM Insulator Condition

Hydro One has experienced numerous porcelain insulators failures due to cement expansion. For example, in March 2015, an insulator on circuit V76R mechanically failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. Similarly, in January 2017, an insulator on circuit HL3 mechanically failed causing the conductor to fall over a roadway in Hamilton. Another example occurred in 2019 on 500kV circuit D501P in Timmins, Ontario with a failed 1962 porcelain insulator. In this case the conductor did not drop, as the idler string held on until crews arrived. In February 2024, an insulator (1958 vintage) on circuit H24S mechanically failed causing the conductor to fall near the ground; the dropped conductor remained energized for a prolonged period until being reported by a member of the public. More recent examples of major insulator failures causing conductor drops occurred in 2025 on 115kV circuits K3D (1956) and R1LB (1950), and 115kV Circuit A7C (1953) in 2026, with the failed insulator vintages indicated in the brackets. Photos of these failures are provided in Figure 46 through Figure 52.

Figure 46: Insulator Failure Resulting in Conductor Drop, Circuit V76R, 2015

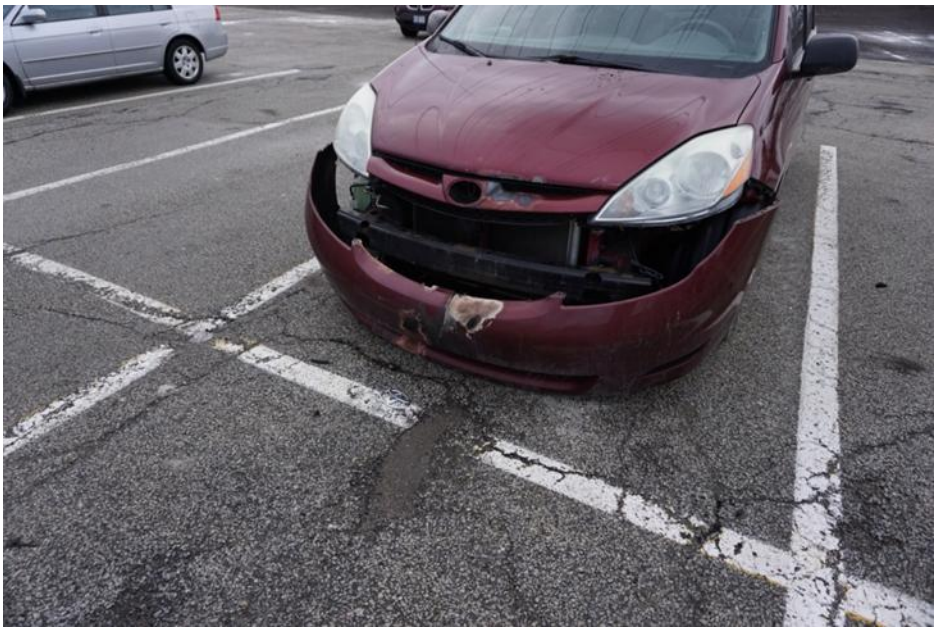

Figure 47: Damage Caused by Insulator Failure, Circuit V76R, 2015

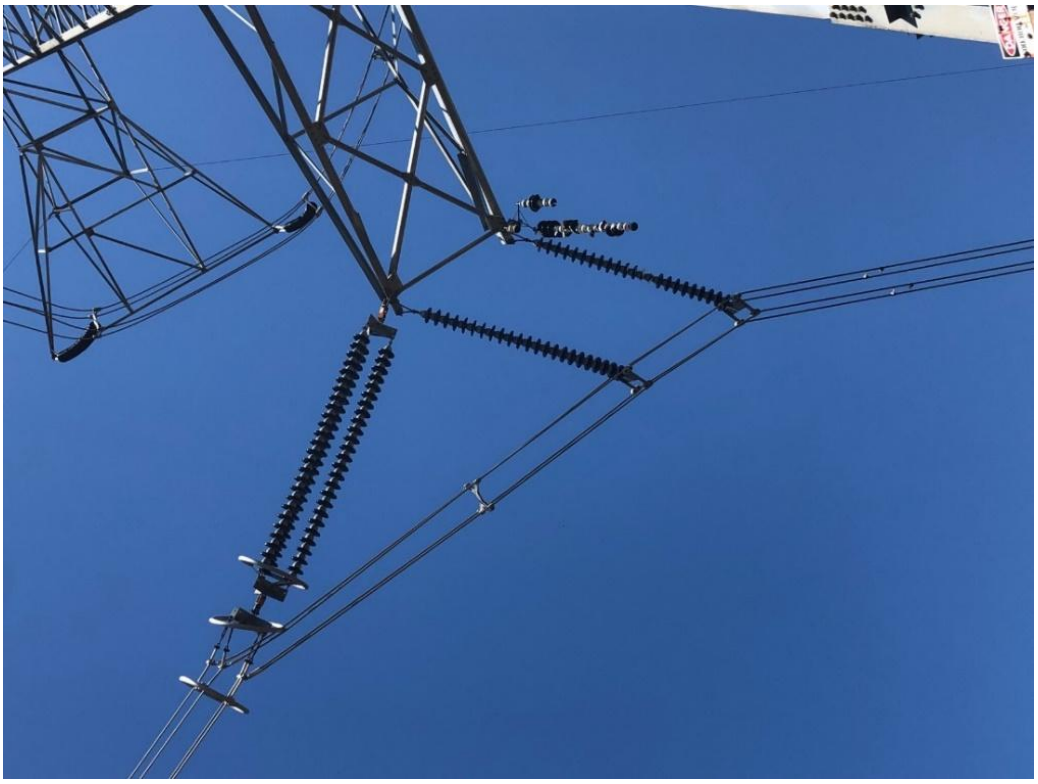

Figure 48: Insulator Failure, Circuit D501P, 2019

Figure 49: Insulator Failure Resulting in Conductor Drop, Circuit H24S, 2024

Figure 50: Insulator Failure Resulting in Conductor Drop, Circuit K3D, 2025

Figure 51: Insulator Failure Resulting in Conductor Drop, Circuit R1LB, 2025

Figure 52: Insulator Failure Resulting in Conductor Drop and Wood Pole Fire, Circuit A7C, 2026

Since portions of Hydro One's polymer insulator population were approaching their ESL, Hydro One retained EPRI to perform a detailed condition assessment of polymer insulators to assist Hydro One in determining the need and pacing of polymer insulator replacement. The condition assessment study, completed in 2018, examined 87 polymer insulators from various manufacturers with 13- 26 years of service. The study evaluated three configurations:

- 230 kV suspension with large corona rings;
- 230 kV suspension with either small (known as a "donut") or no corona rings; and

- 115 kV dead end.

Based on its assessment of 87 insulators, EPRI found that the condition of polymer insulators currently in-service in Hydro One's transmission system varies based on voltage, manufacturer and use of corona rings. The results of this study showed that Hydro One should plan to remove specific 230 kV insulators from service as soon as possible due to immediate or high risk of failure, while other types of 230 kV insulators should continue to be assessed periodically for signs and degree of degradation. EPRI further recommended that linemen check the integrity of these insulators prior to performing any live-line maintenance procedures due to potential safety issues. Based on the results, Hydro One is implementing the following recommendations into its current insulator replacement program:

- Remove from service all 230kV insulators without corona ring;
- Remove from service all 230kV insulators with 4-inch corona rings or smaller; and
- Continue to monitor 230kV insulators fitted with 8-inch corona rings for signs of degradation.

The need to address the polymer insulator issue is reinforced by several failures. Two failures in 2016 on 230 kV circuit T22C polymer suspension insulators resulted in conductor drops, with conductors held within the structure window, as shown in Figure 53 and Figure 54. In 2024, a 230kV polymer insulator failure on circuit P25W resulted in a conductor drop to ground and some grass burning in span, as shown in Figure 55 and Figure 56. Hydro One began replacing polymer insulators in 230 kV dead-end configuration in 2016. More recently, a 115 kV dead-end polymer insulator failure on circuit C2P, as shown in Figure 57 and Figure 58, prompted the inclusion of 115 kV dead-end polymer insulators in the replacement program. Hydro One will continue to incorporate impacted polymer insulators into the insulator replacement program based on observed condition and risk.

In addition to these findings, Hydro One implemented operational restrictions in 2007 on K-Line polymer insulators due to identified safety and reliability concerns. These restrictions apply to 115 kV insulators manufactured before December 2000 and 230 kV

insulators manufactured before 1999. Under these restrictions, live-line work is prohibited, circuits must be isolated and visually inspected before any work is undertaken, conductors supported by the affected insulators cannot be used to support workers, and removed K-Line units must not be reinstalled. The K-Line 230 kV insulators manufactured prior to 1999 were equipped with 4-inch corona rings, which the EPRI assessment identified as requiring replacement due to performance concerns. Although this finding was specific to the 230 kV configuration, the 115 kV K-Line polymer insulators share similar design-era characteristics and were subjected to the same 2007 operational restrictions, indicating comparable risk. Polymer insulators typically have a 30-year ESL. The K-Line 115 kV insulators manufactured prior to December 2000 will be beyond or nearing end of service life during the next rate period, increasing the likelihood of degradation-related failures and extending the operational limitations caused by the 2007 restrictions. Given the safety risks, age-related deterioration, historical failure events, and long-standing operational constraints, the K-Line 115 kV polymer insulators manufactured prior to December 2000 warrant inclusion in Hydro One's insulator replacement program.

Figure 53: Polymer Insulator Failure Resulting in Conductor Drop, Circuit T22C, 2016

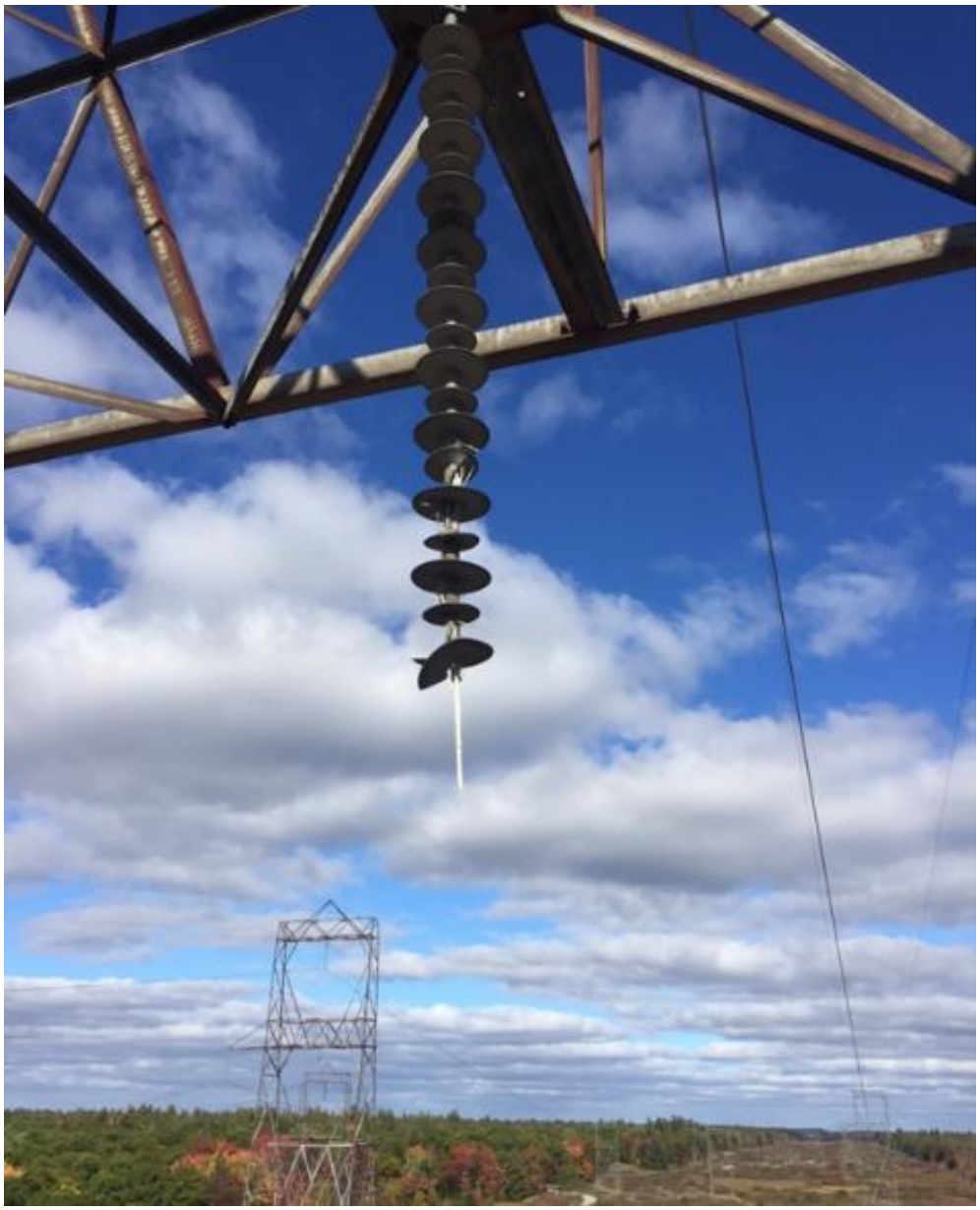

Figure 54: Polymer Insulator Failure Resulting in Conductor Drop, Circuit T22C, 2016

Figure 55: Polymer Insulator Failure Resulting in Conductor Drop and Grass Fire, Circuit P25W, 2024

Figure 56: Polymer Insulator Failure, Circuit P25W, 2024

Figure 57: Polymer Insulator Failure, Circuit C2P

Figure 58: Polymer Insulator Failure, Circuit C2P

2.2.4.4.5 ASSET PERFORMANCE

Figure 59 and Figure 60 illustrate the frequency and duration of insulator-caused circuit outages between, which show downward trend. HOSSM has experienced few outages attributable to insulator. Figure 61 illustrates the number of COB and CP failures over the past ten years is trending lower, indicating that the current COB and CP porcelain insulator replacement program has mitigated the number of insulator failures thus reducing the insulator-related outages.

Failed insulators normally result in a sustained forced outage because of the permanent electrical fault they create. Repair time can be significant, averaging 37 hours per outage, depending on the location and severity of the failure. The majority of the recent failures have been due to defective porcelain or polymer insulators.

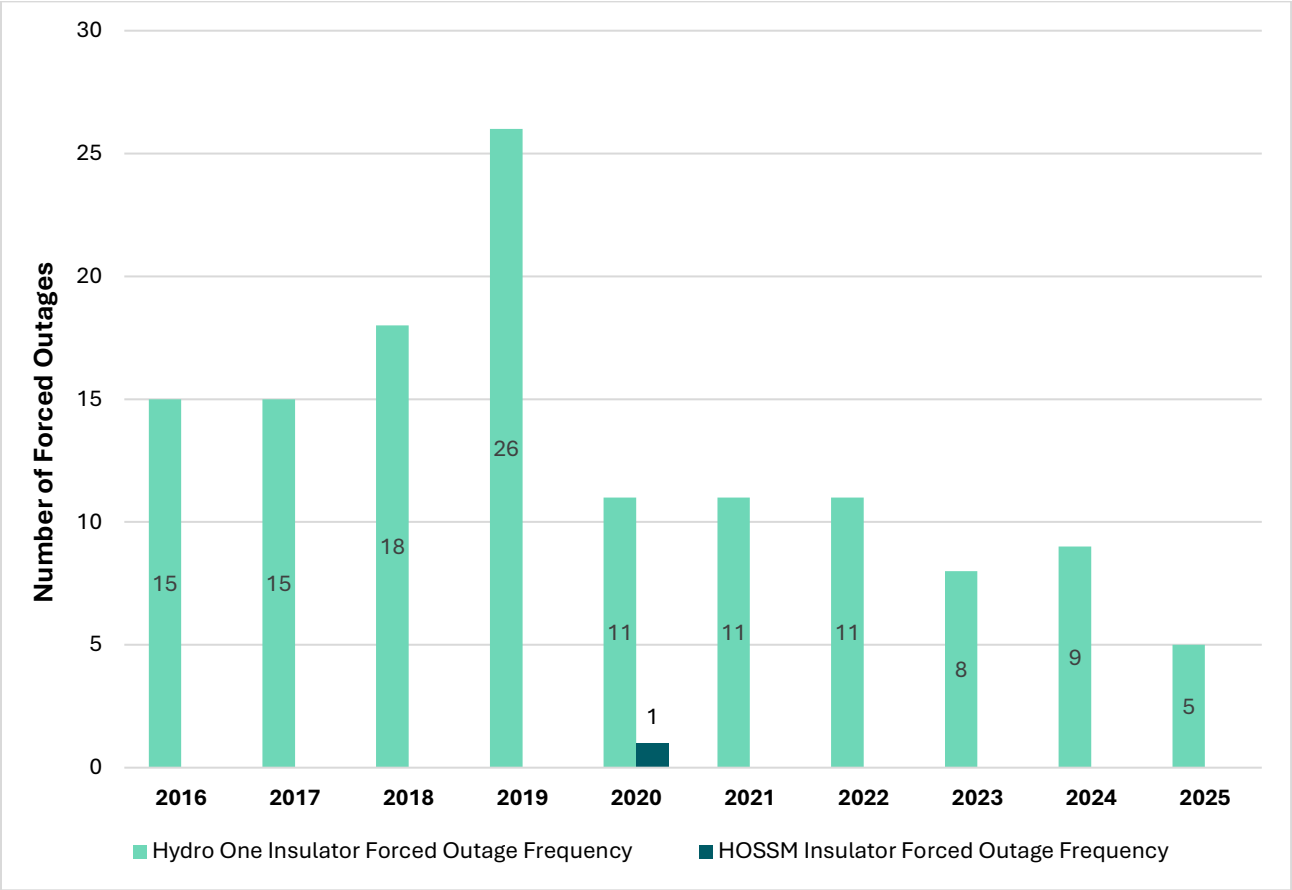

Figure 59: Insulator Forced Outage Frequency

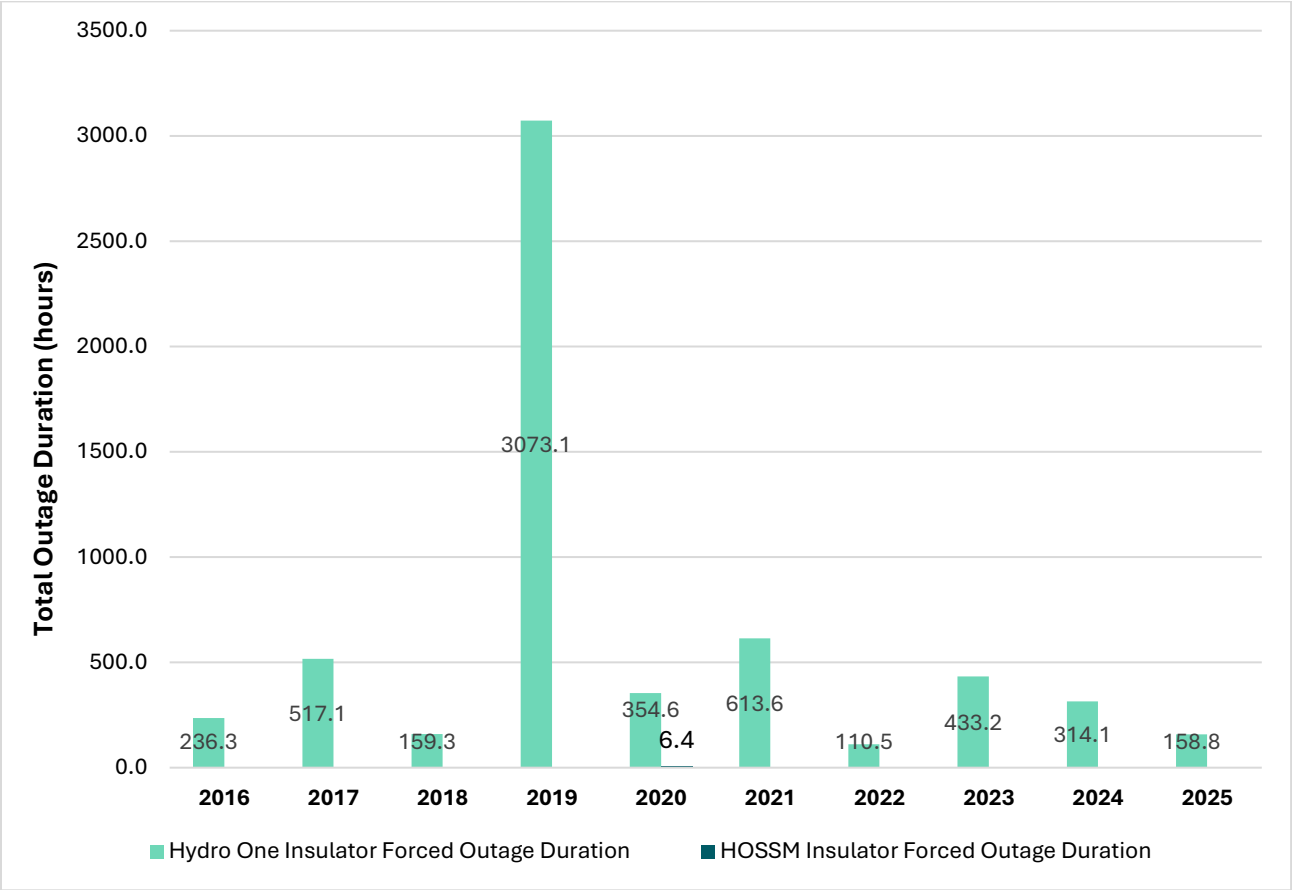

Figure 60: Insulator Forced Outage Duration

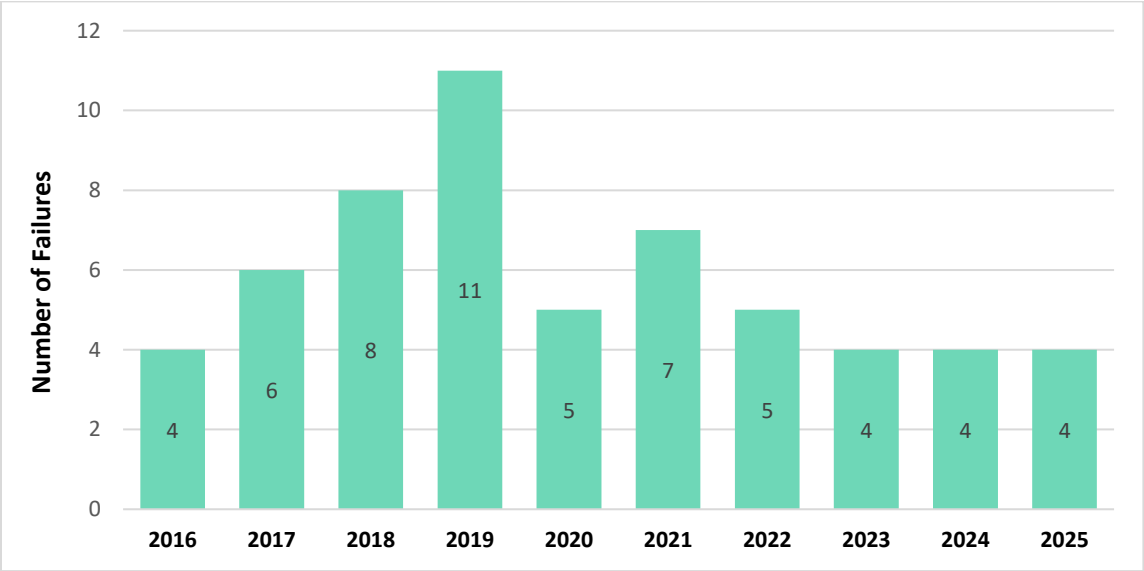

Figure 61: Number of COB/CP Insulator Failures

2.2.4.4.6 ASSET LIFECYCLE

Hydro One's insulator strategy is focused on mitigating public safety risk by targeting defective porcelain insulators and poor condition polymer insulators for replacement.

2.2.4.4.6.1 INSPECTION & MAINTENANCE PRACTICES

Insulators cannot be maintained, repaired or refurbished to extend the service life. They are assessed through various methods and replaced when condition warrants replacement. Condition assessment methods include visual inspections from the air or ground and are bundled with line and structure inspections and patrols.

2.2.4.4.6.2 ASSET REPLACEMENT AND REFURBISHMENT

<u>Porcelain Insulator Replacement</u>

The EPRI testing results discussed above provide overwhelming evidence supporting replacement of defective porcelain insulators to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation provided by EPRI (which is further supported by Hydro One's own experience with failures involving these insulators) is to remove the identified population of COB and CP insulators from service as soon as practically possible. As a result, Hydro One has targeted defective porcelain

insulators for replacement as further discussed in TSP Section 2.11, T-SR-08, Transmission Line Insulator Replacement. As part of this replacement program, the defective insulators are planned for replacement by 2032.

Polymer Insulator Replacement

Polymer insulators in dead-end configurations are known to fail due to their exposure to high electric-field gradients that cause silicone degradation. The degradation exposes the fibreglass rod to moisture which causes rapid deterioration leading to failure. These insulators are being targeted for replacement. In addition to the dead-ends, 230kV polymer insulators without a corona ring, or with corona rings that are four inches or smaller, will also be added to the insulator replacement program at a future date. Hydro One is identifying the number of impacted polymer insulators during the regular line patrols and will incorporate their replacements into the existing insulator replacement program. The issues associated with polymer insulators are further discussed in TSP Section 2.12, T-SR-08, Transmission Line Insulator Replacement.

2.2.4.5 RIGHTS OF WAY

2.2.4.5.1 ASSET DESCRIPTION / PURPOSE

The strip of land that is occupied by a transmission line is referred to as a right-of-way (ROW) or a corridor. Hydro One's in-service ROWs cover an area of approximately 80,000 hectares and consist of 115, 230, 345 and 500 kV circuits. To ensure system reliability and access, Hydro One is responsible for maintaining clearance distances between the energized equipment and the vegetation located on and adjacent to all of these ROWs.

2.2.4.5.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.4.5.3 ASSET DEMOGRAPHICS

Hydro One's service territory is divided into four operational Forestry Zones: North, South, Central and East. These zones have been defined based on similarities in weather patterns and vegetation growth conditions and are used to maximize operational efficiencies.

Hydro One maintains its transmission ROWs on vegetation-clearing cycles of four, six or eight years. Cycle lengths have been set to ensure that ROWs are in good condition and maintain a sustainable level of reliability between maintenance cycles. Fast-growth areas are placed on a shorter cycle. For example, Hydro One's cyclical vegetation management program is primarily completed on a six-year cycle in the Central, East and South zones and on an eight-year cycle in the North. Some corridors in the East and South zones are maintained on a four-year cycle due to faster vegetation growth rates. Maintenance is completed in the North on a longer cycle due to colder temperatures and slower vegetation growth rates.

A summary of Hydro One's ROW route hectares by zone and maintenance cycle is shown in Table 43.

Table 43 - Rights of Way Demographics

Zone	4 Year Cycle	6 Year Cycle	8 Year Cycle	Total Hectares (Zone)
Central	0	14,516	0	14,516
East	444	16,562	0	17,006
North	0	194	30,498	30,692
South	827	17,028	0	17,855
Total	**1,271**	**48,300**	**30,498**	**80,069**

HOSSM's in-service transmission rights-of-way (ROWs) cover approximately 1,738 hectares and support both 230 kV and 115 kV transmission circuits. HOSSM's ROWs are located within Hydro One's North Forestry Zone.

HOSSM performs cyclical vegetation management activities on six-year and eight-year maintenance cycles, based on regulatory requirements and asset criticality. Transmission corridors subject to NERC FAC-003 vegetation management requirements are maintained on a six-year cycle to ensure compliance with applicable reliability standards and to maintain required clearances between vegetation and energized conductors.

HOSSM's 115 kV corridors, all located within the North Forestry Zone, were historically maintained on a six-year vegetation management cycle. The cycle was later extended to eight years to align with Hydro One's North Forestry Zone maintenance schedule, where slower vegetation growth rates support a longer management interval. However, due to the narrower width of HOSSM's corridors, the extended cycle increases the likelihood of requiring interim demand maintenance. As part of its ongoing vegetation management program, HOSSM plans to transition some 115 kV corridors back to a six-year maintenance cycle to better manage risks and reduce the need for additional corrective work.

2.2.4.5.4 ASSET CONDITION

Vegetation on or adjacent to a ROW presents the risk of growing or falling into energized conductors and preventing access to Hydro One's transmission lines. Approximately 13% (i.e. 10,240 hectares) of Hydro One's ROWs are beyond their target clearing cycle and are therefore considered to be in poor condition. ROWs in poor condition are prioritized for maintenance. Figure 62 illustrates the breakdown of Hydro One's ROWs on and off their ideal maintenance cycles for Hydro One, while Figure 63 provides the corresponding breakdown for HOSSM.

Vegetation on or adjacent to a ROW presents a risk of growing into or falling onto energized conductors and can impede access to Hydro One's transmission lines. For vegetation management planning purposes, ROWs are assessed based on adherence to established maintenance cycles rather than observed condition. Vegetation condition is influenced by factors that vary year-to-year, including growing season length, previous cutting activities, weather events, pest and disease pressures, and storm damage, and therefore does not provide a consistent basis for long-term planning. Maintenance cycles have been developed as maximum allowable intervals between vegetation treatments, beyond which the likelihood of safety, reliability, and access issues increases.

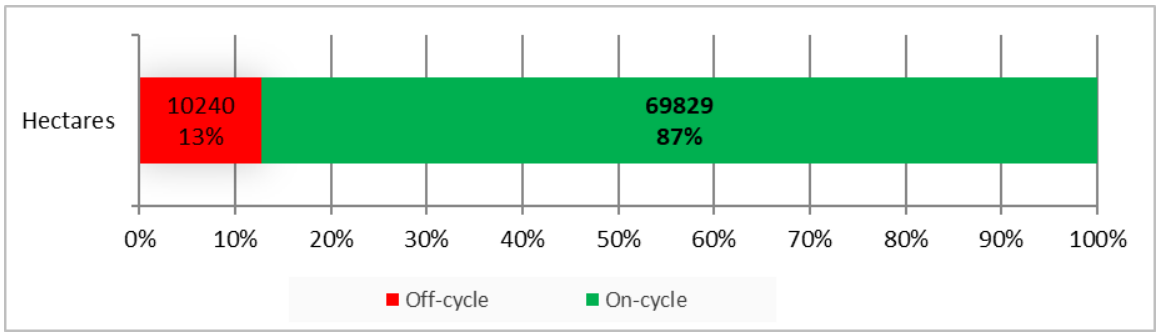

Figure 62: Hydro One Rights of Way Condition

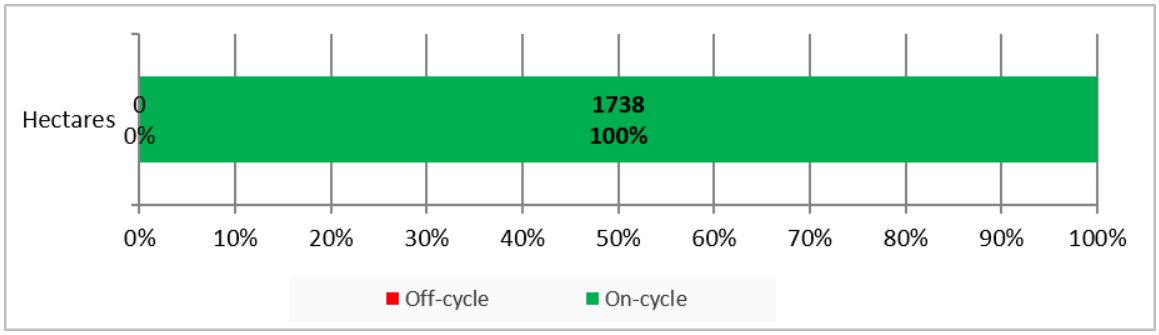

Figure 63: HOSSM Rights of Way Condition

In 2025, off-cycle projects made up approximately 13% of Hydro One's ROW vegetation program, yet they contributed disproportionately to the volume of urgent defects, requiring reactive and unplanned mitigation efforts. If not addressed promptly, or if not identified early, urgent defects may escalate into NERC-reportable incidents, potentially resulting in both financial and non-financial penalties and increasing the risk of service disruptions. Figure 64 shows that 28% of urgent vegetation defects are associated with ROWs that are already one year beyond their target maintenance cycle, while a further 26% occur on ROWs where maintenance is currently due. An additional 7% of defects are observed on ROWs that are due for maintenance within one cycle. In contrast, 39% of urgent defects originate from ROWs that remain on-cycle, indicating that although risk is not eliminated within cycle limits hence the need for monitoring, the majority of urgent defects are concentrated in ROWs that have reached or exceeded their established maintenance cycles.

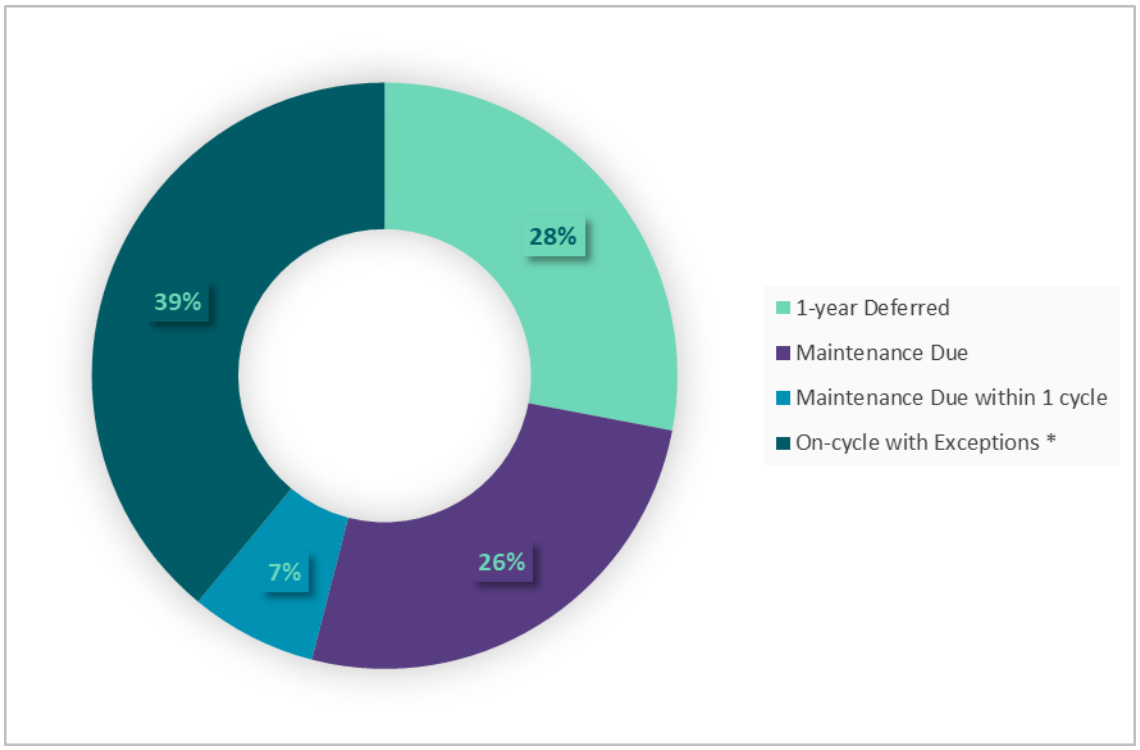

Figure 64: Imminent Vegetation Threats Based on Proximity to Maintenance Cycle Limit

* *On-cycle projects may include components completed outside the standard cycle, executed in phases, or deferred due to operational or budget constraints.*

2.2.4.5.5 ASSET PERFORMANCE

Asset performance for vegetation management can be measured by the number of annual vegetation-caused outages. The majority of Hydro One's vegetation-related outages have been due to trees falling on 115 kV conductors from outside of the ROW due to extreme weather conditions such as heavy winds, snow and/or ice storms.

Hydro One and HOSSM's transmission lines are subject to NERC standard FAC-003 (Transmission Vegetation Management Reliability Standard), which requires Hydro One to report all vegetation-related outages on 230, 345 and 500 kV circuits within its control (excluding causes attributed to natural disasters or human activity such as logging). Vegetation caused outages affecting Hydro One's 115 kV system are not currently NERC reportable. Figure 65 provides the frequency of all vegetation caused forced outages on

Hydro One's and HOSSM's networks (both the NERC reportable and non-reportable outages).[16] The duration of these outages is displayed in Figure 66.

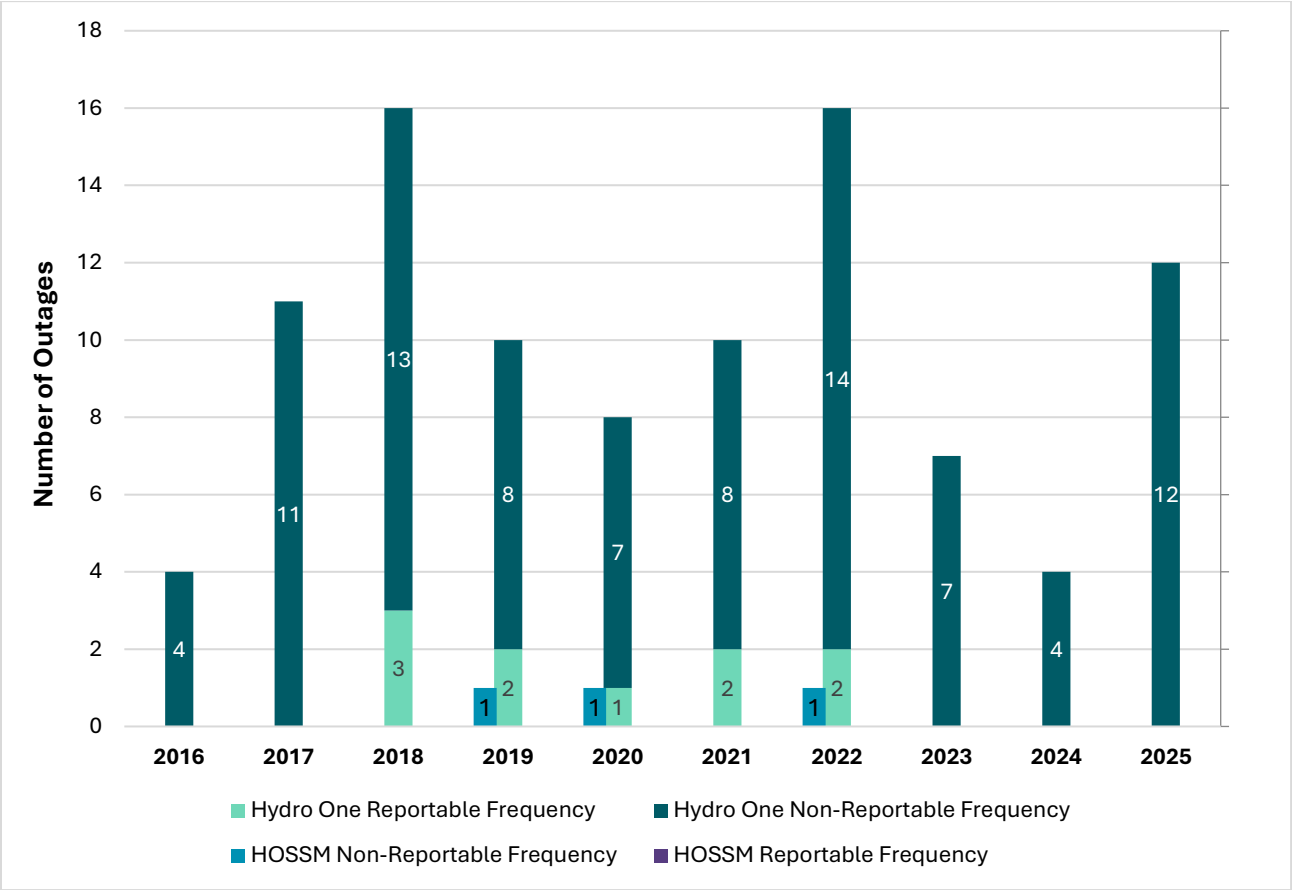

Figure 65: Vegetation Related Forced Outage Frequency

[16] NERC reportable outages have decreased primarily due to changes in NERC's definition of which outages are reportable. For example, there have been less NERC reportable outages in recent years because momentary and human caused outages are now excluded.

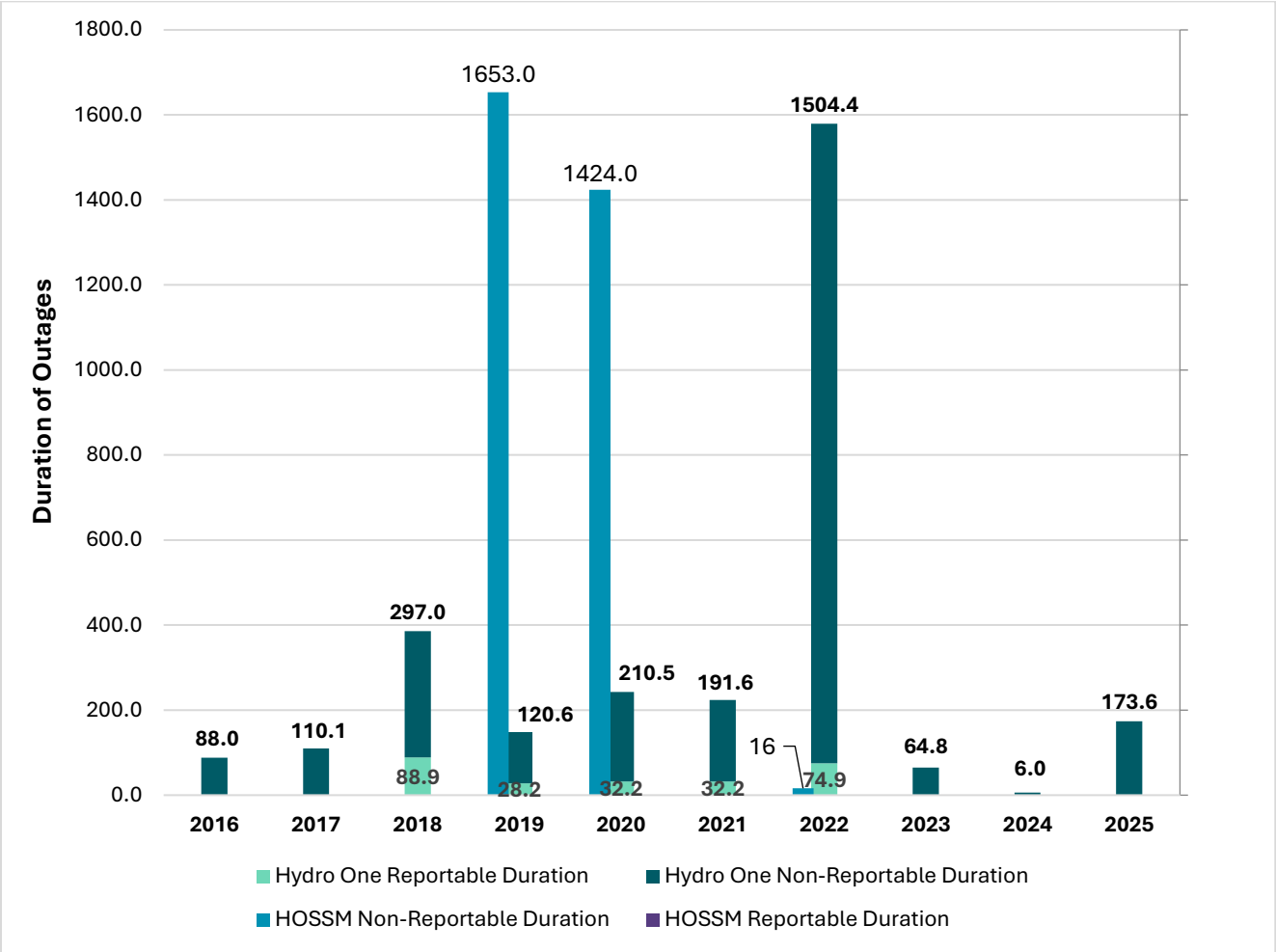

Figure 66: Vegetation Related Forced Outage Duration

Over the last five years vegetation-caused outages have cumulatively contributed to around 100 days of outage hours. These outages were in some cases reported to NERC due to their impact on the bulk electric system. Table 44 presents a summary of those reportable incidents.

Table 44 - Vegetation Related Reportable Forced Outages

Year	Category	Category	Component	Circuit	Duration (minutes)
2020	Foreign Interference	Tree	Blown into Line	X1P	1931
2021	Foreign Interference	Tree	Felled into Line	H23S	529
2021	Foreign Interference	Tree	Blown into Line	D5H	1401
2022	Adverse Weather	Rain	Severe Storm with Winds	X1P	3009
2022	Adverse Weather	Rain	Severe Storm with Winds	D5A	1485

2.2.4.5.6 ASSET LIFECYCLE

Hydro One aims to operate an efficient Transmission Vegetation Management Program while completing the regularly scheduled cyclical maintenance. To meet this maintenance cycle, Hydro One is prioritizing and mitigating vegetation defects that are most likely to impact system reliability, while also introducing flexibility into the standard.

Many of the high priority vegetation defects requiring mitigation are located on ROWs in urban areas, adjacent to residential backyards and community spaces. To ensure that property owners and local communities adjacent to Hydro One's ROWs are aware of maintenance before it occurs, a high number of notifications are performed prior to work execution. Planned and unplanned work has included a large urban component and as a result, Hydro One has been required to perform an increased volume of notifications to ensure that vegetation maintenance can be executed to standard on urban ROWs.

Where maintenance cycles extend beyond targeted cycles, vegetation growth continues to increase along Hydro One's transmission corridors. The current backlog consists of 10,240 hectares of ROW that are behind their targeted vegetation maintenance cycles. Addressing this backlog is necessary to restore targeted maintenance cycles, manage vegetation-related reliability risks and avoid the higher costs associated with clearing overgrown ROWs. To manage the immediate reliability risks associated with the backlog, Hydro One prioritized vegetation maintenance on NERC FAC-003-regulated and critical ROWs while deferring work on portions of the 115 kV network. Additional Brush Control

funding is also required to address the remaining backlog, restore targeted maintenance cycles and reduce vegetation-related risks.

Hydro One Transmission continues to enhance vegetation management through greater flexibility and targeted maintenance practices. Light Detection and Ranging (LiDAR) technology has been integrated into the vegetation management program to proactively identify potential vegetation encroachments along transmission corridors. This enhanced visibility has improved Hydro One's ability to detect previously unidentified defects and emerging risks.

LiDAR is a remote sensing technology that is used by utilities to obtain accurate geospatial images and measurements of circuits and surrounding vegetation. After a successful pilot, Hydro One is formally integrating this approach into the annual vegetation program. This innovative approach will replace traditional ground and helicopter patrols for 50% of the network each year, ensuring full coverage over a two-year cycle. By adopting Virtual Patrols through LiDAR, Hydro One will enhance visibility across the scanned portion of the network, enabling timely, data-driven decision-making, and manage risk.

2.2.4.5.6.1 INSPECTION & MAINTENANCE PRACTICES

Specifically, maintenance of Hydro One and HOSSM's ROW corridors consists of seven programs designed to identify and mitigate potential vegetation encroachments on energized overhead conductors.

1. **Brush Control**: includes manual cutting, herbicide application and/or mechanical clearing to manage vegetation growth on the ROW to ensure adequate clearances and access to Hydro One's overhead circuits.
2. **Line Clearing**: consists of trimming tree branches and removing any unhealthy or danger trees on the edge of or adjacent to the ROW that have the potential to exceed Hydro One's overhead clearances. Split, hanging, uprooted, dead and diseased trees are referred to as danger trees.
3. **Property Owner Notifications**: Prior to the execution of ROW vegetation maintenance, Hydro One contacts all required adjacent property owners to communicate maintenance plans, obtain approval for access onto private property

and acquire permission for any herbicide application during maintenance. Hydro One also actively engages other external stakeholders as required, such as government agencies, municipal officials and special interest groups.

4. **Annual Vegetation Patrol**: In accordance with NERC standard FAC-003, Hydro One is required to annually inspect all of its circuits that are NERC applicable. Consequently, visual or virtual inspections by helicopter, ground patrol, or LiDAR are performed on all NERC applicable circuits not receiving Line Clearing maintenance in the current calendar year.
5. **Demand Maintenance**: addresses vegetation management issues that cannot wait until the next scheduled line clearing or brush control activity.
6. **Grounds Maintenance**: includes grass cutting, snow removal, garbage clean-up, and repair of access barriers and fences on Hydro One's urban ROWs, and is required to comply with local by-laws.
7. **Virtual Patrol**: LiDAR flights conducted across portions of the network will collect data that will be utilized to provide immediate risk reports, full vegetation defect inventory, and imagery to assist in analysis and work planning.

2.2.4.6 SHIELDWIRE

2.2.4.6.1 ASSET DESCRIPTION / PURPOSE

Shieldwire is used to provide lightning protection and grounding continuity to transmission lines. There are approximately 35,300 km of shieldwire strung along Hydro One's overhead transmission lines, consisting of the following five types of shieldwire: (i) Galvanized Steel, (ii) Alumoweld, (iii) OPGW, (iv) ACSR and (v) Copperweld. Alumoweld and OPGW are the most recent types of shieldwire and are currently being installed when poor condition shieldwire is replaced. Further details regarding each type of shieldwire are provided in Table 45.

Table 45 - Shieldwire Description

Type	Vintage	Description
Galvanized Steel	Installed until approx. 1990	Galvanized Steel is the most common type of shieldwire currently on the Hydro One network. However, it is no longer being used for new installations by Hydro One, because the protective zinc coating tends to deteriorate over time and result in a loss of metal, reduction in mechanical strength, and eventual failure of the shieldwire.
Aluminum Cladded Steel (Alumoweld)	Installed since approx. 1960s	Alumoweld is the most recent type of shieldwire installed on Hydro One's network and is being used to replace shieldwire that is in poor condition. Alumoweld shieldwire consists of a thick aluminum cladding used to protect against corrosion and a steel, conductive core.
OPGW	Installed since approx. 1990s	In locations where a fibre optic communication channel is required for telecommunication purposes, Hydro One installs OPGW, which consists of Alumoweld and Aluminum-Alloy stranded shieldwire with a core containing fibre optic strands.
ACSR	Installed as required	ACSR conductors are installed as shieldwire on a limited basis and are used when estimated fault current levels are too high for conventional galvanized steel or Alumoweld wires.
Copper Cladded Steel (Copperweld)	Installed between 1930s and 1960s	Copperweld is an older type of shieldwire that was installed in limited numbers across the Hydro One network. This shieldwire is not capable of adequately sustaining lightning strikes and is therefore targeted for replacement.

2.2.4.6.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.4.6.3 ASSET DEMOGRAPHICS

The average age of Hydro One's shieldwire fleet is approximately 45 years. Approximately 55% of Hydro One's shieldwire fleet is galvanized steel and 33% is Alumoweld. The demographic details of Hydro One's and HOSSM's shieldwire fleet as of year-end 2025 are shown in Table 46 and Table 47. Due to historic construction and demographic patterns, Hydro One is now in a period where many shieldwire sections are approaching ESL (and thus require more condition assessments, which in turn will likely result in additional findings of poor condition assets). It is important to note that shieldwire

replacements are currently based on condition (not ESL). Asset age is, however, useful as a screening criteria, triggering shieldwire assessments, as further discussed below.

Table 46 - Hydro One Shieldwire Demographics

Type	Quantity (km)	Average Age (Years)	ESL (Years)	Beyond ESL (km)
Galvanized Steel	18,693	60	50	13,585
Alumoweld	11,719	31	60	194
OPGW	3,544	15	40	0
ACSR	490	47	90	4
Copperweld	157	66	N/A*	156
Total	34,602	-	-	13,939

** ESL is not applicable to Copperweld as it is considered to be in poor condition regardless of age*

Table 47 - HOSSM Shieldwire Demographics

Type	Quantity (km)	Average Age (Years)	ESL (Years)	Beyond ESL (km)
Galvanized Steel	664	36	50	231
Alumoweld	0	0	60	0
Total	664	-	-	231

2.2.4.6.4 ASSET CONDITION

Hydro One assesses shieldwire for deterioration using the testing methods discussed in the Asset Maintenance and Inspection Practices section below. Deterioration of an overhead shieldwire cannot be stopped or reversed. When shieldwire deterioration is discovered at a tested location, similar levels of deterioration are expected at multiple points across the entire shieldwire line section of the same vintage and type.

Condition assessments are used to verify whether shieldwire is in poor condition (i.e., based on the loss of diameter or tensile strength) and thus warrants replacement. Shieldwire assets that have relatively minor deterioration are considered to be in fair condition and are scheduled for reassessment at a later date. The timeframe for reassessment varies depending on the level of deterioration indicated by the test results.

Shieldwire classified as being in good condition has either been assessed to be in good condition or has not yet reached the age at which shieldwire condition assessment begins.

Notably, Copperweld shieldwire is known to be obsolete due to design deficiencies (which render it incapable of adequately sustaining lightning strikes) and is considered to be in poor condition.

The condition of Hydro One's and HOSSM's shieldwire fleet is summarized in Figure 67 and Figure 68. The "needs assessment" category refers to shieldwire which have reached the age threshold for condition assessment / re-assessment and will be assessed in the future under the shieldwire condition assessment program.

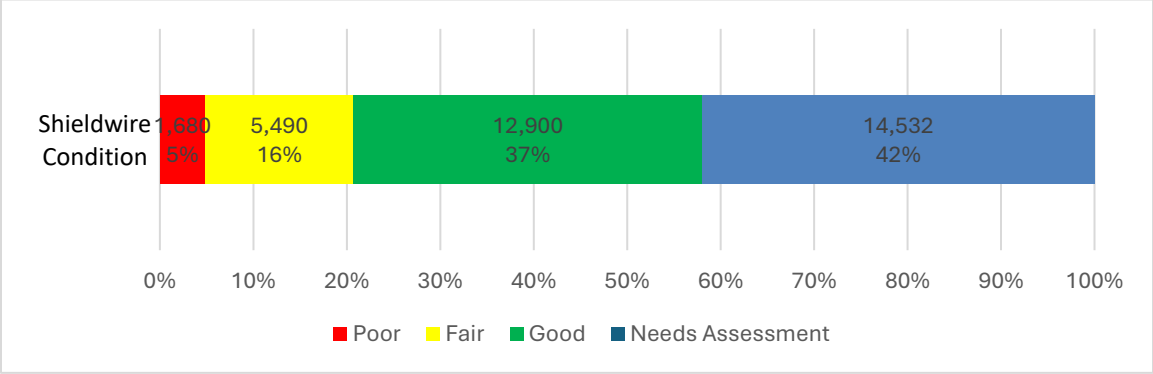

Figure 67: Hydro One Shieldwire Condition

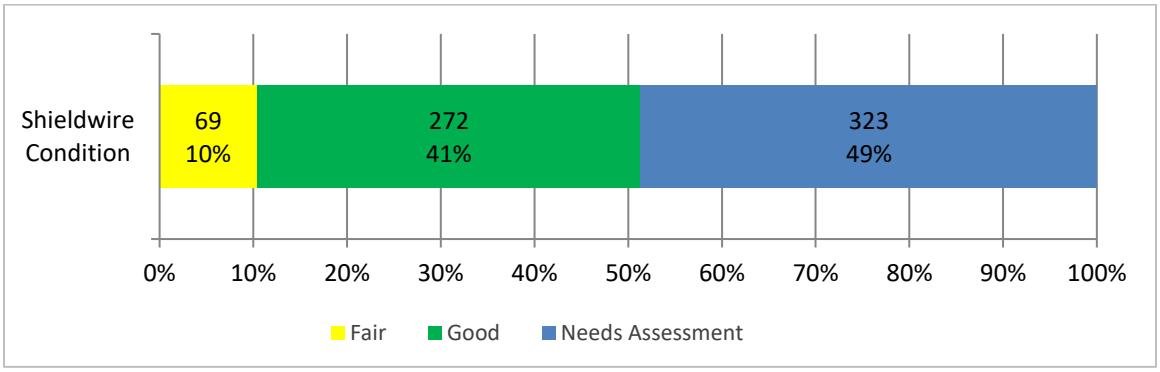

Figure 68: HOSSM Shieldwire Condition

2.2.4.6.5 ASSET PERFORMANCE

Asset performance for shieldwire is measured by the number of shieldwire caused outages that occur each year. The majority of Hydro One's shieldwire caused outages occur during extreme weather conditions such as heavy winds, snow, and/or ice storms. Figure 69 and Figure 70 provide a summary of all shieldwire caused forced outages. HOSSM has experienced few outages attributable to shieldwire. Given that performance is a lagging indicator of condition and most of these outages were caused during extreme weather conditions, these figures are intended to provide a picture of how the shieldwires are currently performing but are not used to drive investment decisions.

The frequency of shieldwire caused forced outages has seen an increase in 2018 and 2019 before decreasing in 2020 and beyond as seen in Figure 69, while outage duration has decreased in the past five years as seen in Figure 70.

The higher frequency in 2018 is due to an ice storm in April, which resulted in four registered outage events due to broken shieldwire. Of these four events, only one resulted in a sustained duration of almost two days. The higher frequency of outages in 2019 is due to a heavy snow and ice loading event on circuit A5A in November, which resulted in eight registered outage events due to broken shieldwire. Of these eight events, the longest one lasted about six hours, while the others were under ten minutes.

Delivery point outages are common when shieldwire failure occurs, as the broken shieldwire typically makes contact with the conductors before falling to the ground. In addition, broken and hanging shieldwire can expose members of the public or Hydro One employees to significant safety risk. The duration of shieldwire related outages is dependent on the geographic location and accessibility of the fault. As a result, the number of outages in a given year is only one factor that will impact the total duration of outages in that year.

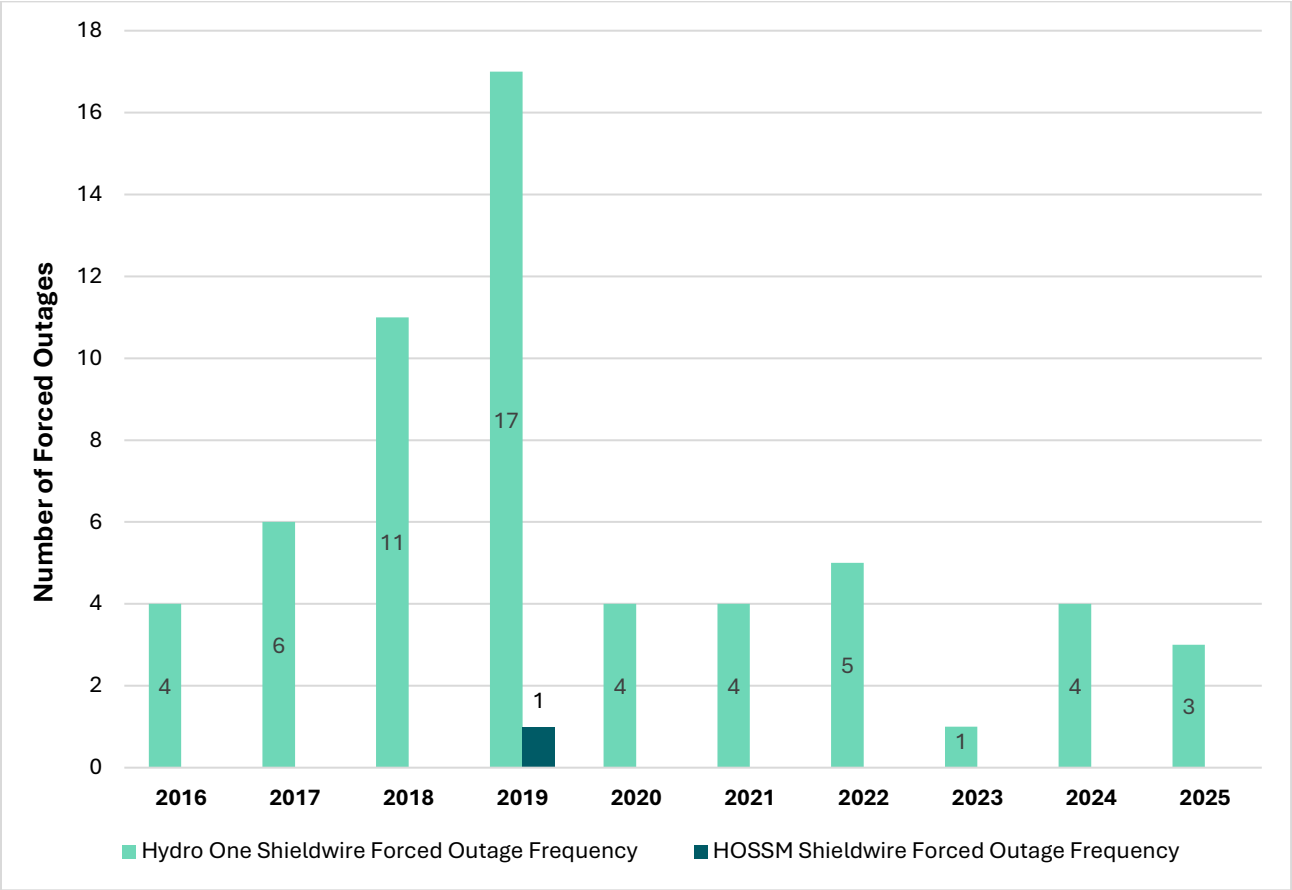

Figure 69: Shieldwire Forced Outage Frequency

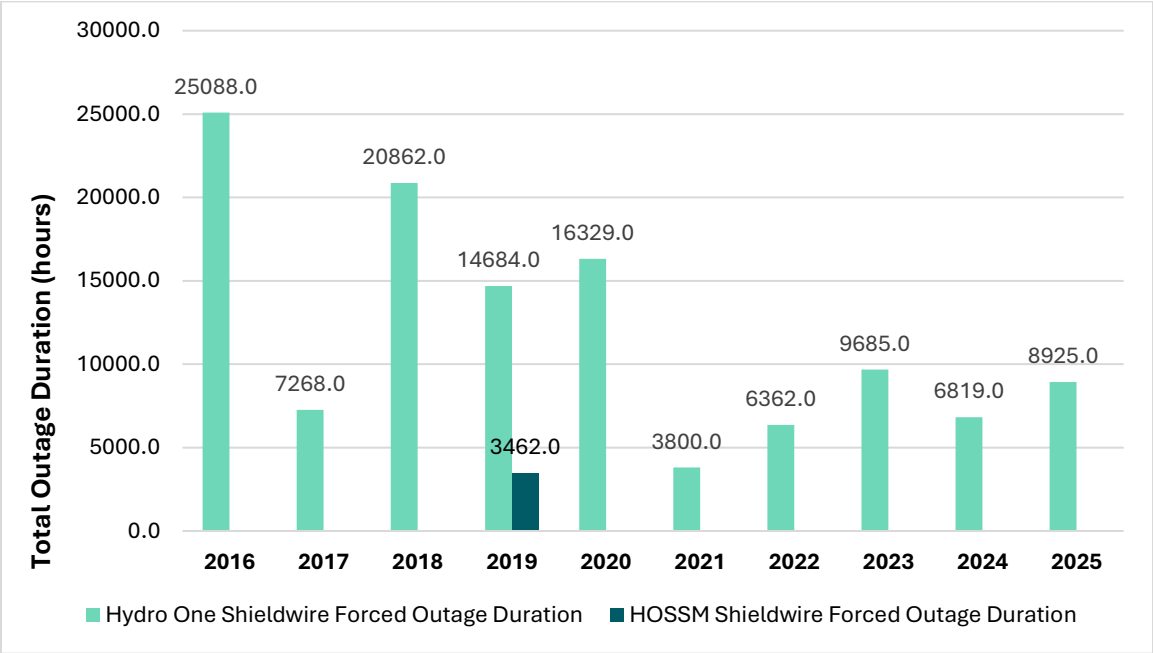

Figure 70: Shieldwire Forced Outage Duration

2.2.4.6.6 ASSET LIFECYCLE

Hydro One's shieldwire asset strategy is to maintain system reliability and public and employee safety by actively replacing all shieldwire assessed to be in poor condition. Hydro One currently uses a condition-based asset management strategy to assess and prioritize the replacement of its shieldwire fleet. Age is used as a criterion for identifying assessment candidates.

2.2.4.6.6.1 ASSET INSPECTION & MAINTENANCE PRACTICES

Hydro One does not replace shieldwire based upon age, and poor condition shieldwire cannot be maintained or repaired to extend life. Rather, Hydro One's shieldwire population is monitored through the condition assessment program and is replaced as condition warrants. Line sections of shieldwire are targeted for condition assessment after reaching an established age threshold, which varies between 25 and 50 years depending on the shieldwire type, as summarized in Table 48 below.

Table 48 - Shieldwire Condition Assessment Ages

Shieldwire Type	Age for Condition Assessment
Galvanized Steel	25 years
Alumoweld	40 years
ACSR	50 years
Copperweld	N/A (As noted above, all Copperweld shieldwire is considered poor condition)
OPGW	Condition assessment process for OPGW is currently being developed.

Hydro One's shieldwire fleet is regularly visually inspected through helicopter and foot patrols, as discussed below under "Cyclical Based Maintenance Activities". These visual patrols will include the findings of the surface conditions and any damages of the shieldwire.

Hydro One performs testing to empirically establish the condition of its shieldwire, which allows Hydro One to operate verified good condition shieldwire well beyond their ESL. This approach prevents the replacement of shieldwire that does not need replacement, regardless of age, thereby maximizing asset useful life. Hydro One uses Kinectrics LineVue scans, or laboratory testing to establish the shieldwire condition. Laboratory testing involves dissecting a five meter shieldwire sample, and then performing the following tests on the sample: extent and severity of rust, remaining zinc (for galvanized steel), torsional ductility, and tensile strength.

Since 2016, Hydro One has been performing the majority of its shieldwire condition assessments through the Kinectrics LineVue tool. This tool is used to travel an entire sampling span between two structures of shieldwire to infer the tensile strength by magnetically sensing the remaining cross-sectional area. LineVue is non-destructive and allows for a greater number of condition assessments per year and is cost efficient when compared to removing samples for laboratory testing. LineVue also provides a visual inspection assessment of the extent and severity of corrosion.

Currently, 14,855 circuit km (42%) of Hydro One's shieldwire fleet has reached the age threshold for condition assessment, which includes 5,025 circuit km that require first time assessment and 9,830 circuit km that require reassessment. These assessments are required to plan, schedule and execute replacements of poor condition shieldwire.

2.2.4.6.6.2 ASSET REPLACEMENT AND REFURBISHMENT

To prevent shieldwire related outages and reduce the risk to public safety, Hydro One is focusing on replacing all shieldwire that has been confirmed through condition assessment to be in poor condition. Going forward all shieldwire that requires replacement will be replaced with Alumoweld or OPGW shieldwire, with the exception of any line sections that require ACSR to withstand higher fault currents.

The proportion of shieldwire replacements using OPGW continues to grow due to provincial broadband deployment initiatives that rely on utility corridors for fibre optic backhaul. In addition, the need for reliable Hydro One owned fiber optic communication has increased significantly in recent years. The reliability performance and considerable expense of leased services, together with the discontinuation of certain services, support the installation of Hydro One owned OPGW.

2.2.5 ASSET COMPONENT INFORMATION - OTHER LINES ASSETS

This section discusses other transmission line assets, including U-bolts, switches, dampers, ground wires, and other hardware components.

2.2.5.1 ASSET DESCRIPTION / PURPOSE

U-bolt Hardware

U-bolt hardware is the physical link between a transmission structure and insulator as shown in Figure 71. The majority of suspension circuit structures contain U-bolt hardware. U-bolt are widely used for all types of structures. In general, wood pole structures have a shorter ESL compared to that of U-bolt hardware. Under normal circumstances, poor condition wood pole structures are replaced prior to U-bolts degrading to poor condition. Poor condition wood poles are either replaced under the wood pole replacement program or line refurbishment projects. As part of the wood pole replacement, all associated

insulators and U-bolt hardware are also replaced. Therefore, this section focuses on management of conductor U-bolt hardware on suspension type steel structures and composite poles.

Figure 71: U-bolt on a Suspension Structure

Lines Switches

Transmission line switches are primarily used to sectionalize lines and isolate customers during planned and unplanned outages. Transmission line switches can be generalized into two types: In-Line Disconnect switches and Mid-Span-Openers (MSO).

2.2.5.2 ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

2.2.5.3 ASSET DEMOGRAPHICS

U-bolt Hardware

The ESL for U-bolt hardware is 65 years. However, U-bolt replacement is primarily driven by condition assessments. There are approximately 82,600 steel suspension circuit structures in the overhead transmission network containing U-bolts. About 26,500 of those are currently beyond ESL.

Line Switches

Time-based preventive maintenance is performed on Hydro One line switches. During maintenance, switch functionality is verified and associated defects are reported for corrective repair or future replacement is planned. There are currently 133 line switches in the system, ranging as old as 115 years.

2.2.5.4 ASSET CONDITION

U-bolt Hardware

U-bolt hardware under suspension configuration deteriorates over time due to the swinging movement of the attached insulators and conductors. The swinging causes friction and wear on the U-bolt hardware or tower eye. Over time the cross-sectional area of the U-bolt and/or the tower eye wears out as shown in Figure 72. Eventually the hardware will no longer have the mechanical strength to support the suspended insulator and conductor, leading to a catastrophic failure.

Figure 72: Worn U-bolt

Various external factors, such as wind, weather and circuit configuration, can impact the rate of deterioration of U-bolt hardware. Accordingly, age alone is not an indicator of physical condition. Hydro One visually assesses U-bolt hardware through detailed helicopter inspections or climbing inspections. Figures 73 and 74 present the condition of U-bolts on steel and composite circuit structures for Hydro One and HOSSM, respectively, based on the percentage of wear observed. Structures that are less than 25 years old and have no available condition information are classified as Good rather than Needs Assessment.

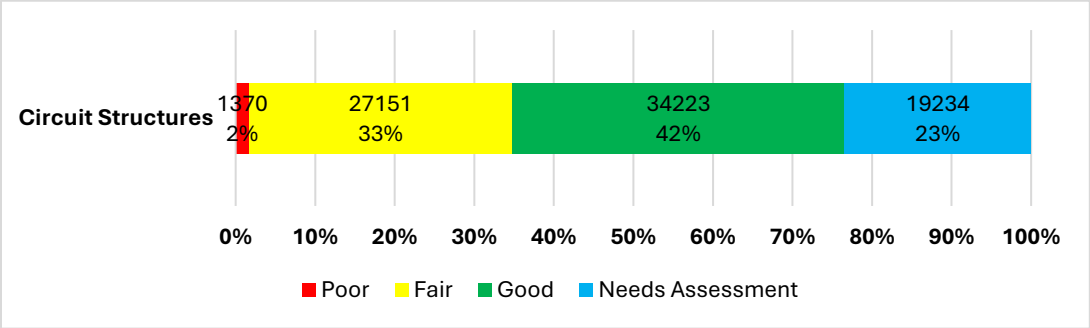

Figure 73: Hydro One – U-bolt Condition

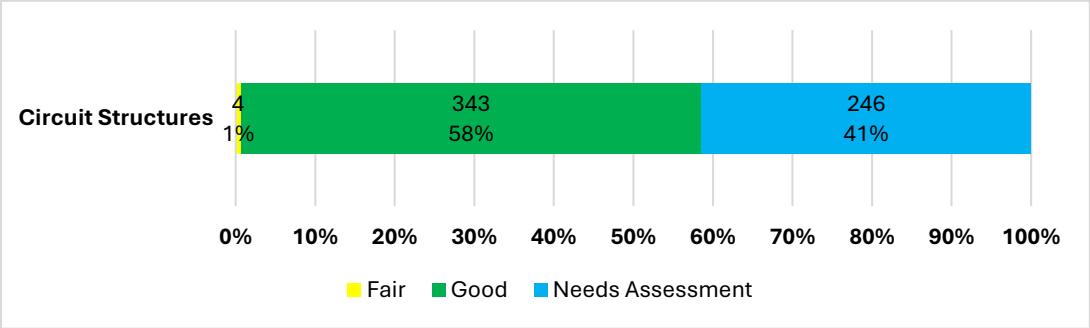

Figure 74: HOSSM – U-bolt Condition

Out of approximately 82,000 steel suspension circuit structures within the Hydro One transmission network, 1,370 circuit structures have been identified with U-bolts in poor condition and will require replacement. There are no known, poor condition U-bolts in the HOSSM network. Poor condition U-bolts are replaced through several programs, such as

Planned Corrective, Line Refurbishments and Insulator or Wood Pole Replacement programs.

Line Switches

Line switches are assessed and maintained every ten years on a cycle. Any defects are either repaired at that time or planned for repair to ensure that line switches remain in functional condition.

2.2.5.5 ASSET LIFECYCLE

The asset strategy for other lines components (e.g. U-bolts, downgrounds, bondwire, structure signs) is to perform preventive maintenance and condition assessments along overhead transmission lines to identify defective equipment and components prior to failure. Corrective and demand maintenance, as described further below, are executed to repair defective components, including U-bolt and other hardware components that are in poor condition and to minimize any customer impact, system reliability and public safety risk.

2.2.5.5.1 ASSET INSPECTION AND MAINTENANCE PRACTICES

Preventive Maintenance and Asset Assessment

The overhead lines maintenance program encompasses cyclical and non-cyclical based maintenance activities. Cyclical based maintenance activities include helicopter patrol, DHI, foot patrol, thermovision patrol, switch maintenance and insulator washing. Non-cyclical based activities include DHI, climbing inspections and other asset assessment activities described in the corresponding sections for conductor, shieldwire, structures and insulator.

Cyclical Maintenance Activities

Helicopter and foot patrols are used to assess the condition of transmission line components (including u-bolts). Helicopter and DHI patrols are primarily intended to detect defects from the air whereas foot patrols are ground based. The current patrol cycles are as follows:

i. For circuits newer than 25 years – Foot patrols every 12 years; helicopter every 3 years for steel lines and 2 years for wood lines.
ii. For circuits older than 25 years – Alternate foot patrol and DHI every 6 years (each type of patrol is done every 12 years); helicopter every 3 years for steel lines and 2 years for wood lines.

Thermovision patrol identifies defective transmission line components by detecting their heat signature using infrared cameras. Switch maintenance inspects and maintains switch components, as well as verifies switch functionality on a 10-year cycle. Insulator washing is performed on transmission structures located near urban highways and road crossings where salt contamination is a concern.

Non-cyclical Maintenance Activities

Climbing inspections are performed on selected structures located in no-fly regions that cannot be inspected by helicopter. Typically, structures with higher public safety risk are selected. Additionally, starting in 2026, Aviation Services will coordinate third-party contracted Remotely Piloted Aircraft Systems (RPAS) (drones) for use on circuits in no-fly regions.

Demand Maintenance

Demand maintenance is needed to respond to emergencies and to restore power when necessary. This program includes activities such as unplanned data collection, emergency component repair and trouble call response. This program also addresses problems identified during line patrols that need a near-term response to prevent a potential outage or to address a serious safety issue.

Planned Corrective Maintenance and Projects

Planned corrective maintenance activities and projects include minor corrective work and technical support to resolve reliability and safety problems with transmission line assets. These activities and projects are developed using the data collected during patrols and asset assessment activities, as well as information about equipment reliability performance.

Planned corrective maintenance addresses multiple line components including defective ground wire connections, missing or broken safety signs and nomenclature signs, U-bolt hardware that supports the insulator strings and conductors, and dampers that limit conductor vibration.

2.2.5.5.2 ASSET REPLACEMENT AND REFURBISHMENT

U-bolt hardware

To maintain system reliability and reduce the risk to public safety, Hydro One will continue to utilize DHI, climbing and RPAS inspection to assess the U-bolt condition on circuits that have reached the age threshold for condition assessment.

Poor condition U-bolts cannot be repaired and are therefore targeted for replacement. A U-bolt is considered hardware associated with the structure/insulator. Therefore, component replacement programs such as wood pole replacement, insulator replacement or line refurbishment projects will typically include replacement of U-bolt hardware on the circuit structure. For example, during insulator replacement, the associated U-bolt hardware will be replaced at the same time for execution efficiency. Poor condition U-bolts that are not addressed through component replacement programs will be replaced through the planned corrective program.

Lines switches

Switches that are inoperable, obsolete or in poor condition are targeted for replacement. The intent is to proactively replace switches prior to failure, minimizing customer and system impact in case the switch is required to operate.

Emergency Replacement

Each year, a number of transmission line components fail or are identified to be in imminent danger of failure, due to adverse weather, component deterioration, vandalism, or accidents. Replacement or repair of these line components is carried out under a demand emergency program to minimize reliability and safety risk. The type of emergency work covered includes replacement of failed or defective transmission line components

such as wood structures, cross-arms, towers, insulators, conductor, shieldwire and hardware.

SECTION 2.3 – TSP – BENCHMARKING AND OTHER STUDIES

2.3.1 INTRODUCTION

Benchmarking studies and third-party assessments (the studies) provide Hydro One with insight into the management of its transmission assets and inform the proposed capital expenditure plan. Overall, the studies indicate that Hydro One's asset management and capital execution practices are generally aligned with industry peers and established practices, and that capital work is delivered in a structured and controlled manner.

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

- Transmission Capital Project Execution Review – E Source
- Transmission Wood Pole Benchmarking Study – Guidehouse and First Quartile

2.3.2 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.

2.3.2.1 TRANSMISSION CAPITAL PROJECT EXECUTION – E SOURCE STUDY OVERVIEW

E Source was engaged to re-examine Hydro One's transmission capital project execution process, including planning, design, project controls and governance, relative to industry standards and the processes used by other large transmission companies. E Source (previously UMS) completed a similar report provided in Hydro One's prior Application (EB-2021-0110). For this Application, E Source prepared a report entitled "Hydro One Networks Inc. - Transmission Capital Project Execution Review" (E Source Report), which is Attachment 1 to this section.

To evaluate the effectiveness of Hydro One's capital delivery model, E Source:

- Designed and administered an assessment framework to gauge maturity across 10 performance domains based on PMBOK, using defined maturity rating scale criteria;
- Reviewed relevant documentation and project performance data;
- Interviewed 24 Hydro One representatives, from Superintendent to Vice President, across organizations with primary or key secondary roles in executing transmission capital projects;
- Identified and engaged a comparator group (Peer Group Panel) of 14 Canadian and U.S. electric utilities based on defined selection criteria; and
- Surveyed the comparator group and integrated insights from interviews and documentation reviews to determine Hydro One's absolute maturity level and comparative (quartile) standing across each performance domain.

STUDY FINDINGS

The findings in the E Source Report are summarized in Table 1.

Table 1 - Key Study Findings

Key Study Findings	Reference
Hydro One's project management practices compare well to the Peer Group Panel. Hydro One ranked second quartile or better in 9 of the 10 performance domains, which, in their totality, indicate that Hydro One meets the requirements to properly execute large capital plans.	E Source Report, pp. 6–7, 15
Hydro One's maturity increased in 9 of the 10 performance domains; Scope Management remained "Fully Integrated."	E Source Report, pp. 7–8, 15
Cost, Scope, Resource, Quality, Contract, and Communications Management achieved top-quartile performance.	E Source Report, pp. 16–22

The E Source Report also identified opportunities for continued improvement in three areas. E Source noted Hydro One's improvement in Schedule Management, with its comparative rating improving from the median to the second quartile. With a maturity rating between "Competent" and "Fully Integrated," E Source identified an opportunity to continue progressing toward full integration of scheduling, cost and resources, supported by greater rigour in progress reporting (p. 18). For Resource Management, E Source

indicated that Hydro One's second-quartile performance could be enhanced by progressing toward full integration and strengthening the current matrix structure through clearer roles and responsibilities (p. 19). E Source also indicated that Hydro One's third-quartile performance in Technology Enablement could be improved by enhancing Hydro One's information technology platforms to replace fragmented legacy systems, thereby improving visibility into analytics and project management-related metrics (p. 8).

As part of Hydro One's ongoing approach to continuously improving capital project execution, the Transmission Capital Work Execution Strategy in TSP Section 2.11 describes several initiatives and process enhancements that align with these areas and support the continued development of Hydro One's execution capabilities. Hydro One has implemented standardized scheduling practices and tools, along with improved outage planning and work bundling approaches to support schedule efficiency.

Enhancements to forward-looking resource planning and the use of external delivery partners further support the effective alignment of resources with the growing capital work program. TSP Section 2.11 also describes strengthened Station Services integration, estimating practices, change management process and governance improvements, as well as enhanced cross-functional integration throughout the project lifecycle.

Investments in data and analytics capabilities, including Power BI reporting tools, SAP S/4HANA, and planned enhancements to project data integration and analytics, support continued improvement in Technology Enablement.

2.3.2.2 TRANSMISSION WOOD POLE REPLACEMENT PROGRAM STUDY - GUIDEHOUSE AND FIRST QUARTILE

STUDY OVERVIEW

Guidehouse Canada Ltd. (Guidehouse) and First Quartile Consulting (First Quartile) jointly undertook a benchmarking study for Hydro One regarding the replacement rates and demographics of transmission wood pole structures. Their report, entitled "Transmission Wood Pole Benchmarking Study," is Attachment 2 to this section.

To evaluate Hydro One's transmission wood pole program performance, Guidehouse and First Quartile:

- Established the benchmarking framework by identifying a representative comparison group of North American utilities, defining relevant asset and operational characteristics, and developing comparison metrics;
- Collected and validated data from Hydro One and participating utilities through the First Quartile benchmarking survey, a supplemental questionnaire, and publicly available Canadian utility data;
- Conducted quantitative analysis to compare transmission wood pole demographics, expected service life, and historical and planned replacement rates across the comparison group;
- Drew insights and conclusions based on observed trends to support an assessment of Hydro One's replacement practices relative to industry peers.

STUDY FINDINGS

The Transmission Wood Pole Replacement Program Study's findings are summarized in Table 2.

Table 2 - Key Study Findings

Key Study Findings	Reference
The average age of Hydro One's transmission wood pole structures (36 years) is below the comparison group average of approximately 45 years. The age distribution of Hydro One's wood pole structures is highly variable, with relatively higher proportions of both older (pre-1960) and newer (post-2000) installations compared to peers.	Report, p. 7
Hydro One's expected service life for wood pole structures of approximately 50 years is near the median of the comparison group.	Report, p. 7
Hydro One's wood pole replacement rate of approximately 2.2%–2.4% annually (2024 actual and 2025–2029 planned) is broadly in line with the comparison group median of approximately 2%.	Report, p. 9

The benchmarking results demonstrate that Hydro One's current transmission wood pole replacement rates are broadly aligned with those of the comparison group. The evidence also supports the conclusion that replacement requirements are expected to increase over time as condition-driven needs emerge across the wood pole fleet. Accordingly, while current replacement pacing is consistent with industry peers, an increase in replacement activity is a reasonable and evidence-based expectation.

2.3.3 ATTACHMENTS: STUDIES

Table 3 - Attachments

Attachment	Report
1	Transmission Capital Project Execution Review – E Source
2	Transmission Wood Pole Benchmarking Study – Guidehouse and First Quartile

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FINAL Report

Hydro One Networks Inc.

Transmission Capital Project Execution Review

Submitted by

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June 2026

TABLE OF CONTENTS

SECTION I – EXECUTIVE SUMMARY 3
Approach and Methodology 4
Performance Comparisons and Assessments 7
Summary 7
SECTION II - INTRODUCTION 9
Report Outline 9
E Source Qualifications 10
SECTION III – PROJECT APPROACH 11
Assessment Framework 12
Comparator Selection 12
Normalization Factor Development 13
Information Collection 13
SECTION IV – STUDY RESULTS 15
Cost Management 16
Scope Management 16
Schedule Management: 17
Resource Management 18
Risk and Contingency Management 19
Quality Management 20
Contract Management 21
Communications Management 22
Integration Management 23
Technology Enablement 25
APPENDIX A – E SOURCE QUALIFICATIONS 26
APPENDIX B – PROJECT MANAGEMENT EVALUATION FRAMEWORK 32
PMBOK – Informed Performance Domains 32
Maturity Scale Rating Criteria 33
APPENDIX C – PEER GROUP TRANSMISSION SYSTEM DEMOGRAPHICS 40

SECTION I – EXECUTIVE SUMMARY

In connection with Hydro One Networks Inc.'s ("HONI") Custom Incentive Rate ("CIR") application for 2028-2032 transmission and distribution rates, E Source, the acquirer of UMS Group, has undertaken a study with an approach and methodology similar to that conducted during the 2020 / 2021 timeframe[1], to examine the processes used by HONI to plan, approve, execute, and monitor transmission capital projects.

In accomplishing this objective, E Source:

- Conducted a series of interviews with HONI individuals in relevant lines of business (e.g., Project Control, Project Delivery, Strategic Projects, Station Services, Transmission Lines, and Station Construction),
- Reviewed relevant reports, procedures, and project performance data,
- Identified and recruited a Peer Group Panel of 14 electric utilities, based on criteria presented in Section III, "Project Approach,"
- Designed and administered an assessment framework (Maturity Rating Scales used to gauge an electric utility's progress from low ("Novice") to high ("Beyond Standards") across 10 Performance Domains, 9 of which comprise the Project Management Institute's Project Management Book of Knowledge – "PMBOK"[2]), and
- Surveyed the Peer Group Panel and combined with the insights gleaned from the HONI interviews, determined HONI's absolute ("maturity level") and comparative ("quartile") standing across each of the 10 Performance Domains.

As summarized below and expanded upon in Section IV, "Summary of Results," this study yielded insights from both industry and HONI-specific perspectives.

[1] UMS Group was acquired by E Source in November 2023, thus maintaining the analytical frameworks and methodologies used in the previous assessment. Many of the key members of the project team were retained, further ensuring consistency and comparability between the two assessments.

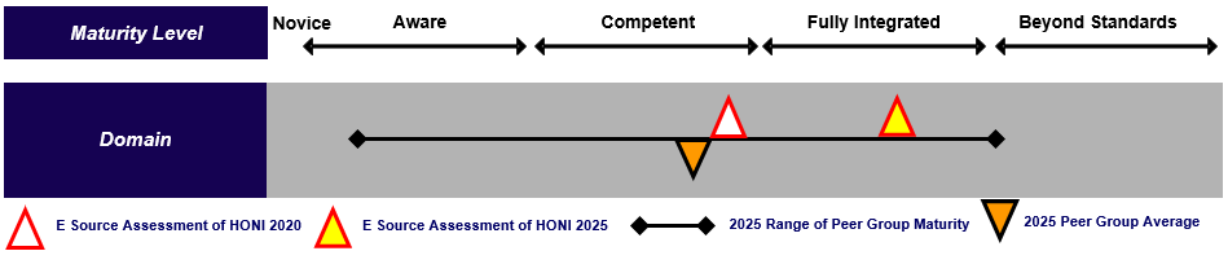
[2] Initially published in 1996, the PMBOK is a fundamental resource for effective project management in any industry and has gained increasing acceptance as a standard in the utility industry for measuring project management effectiveness. Though more recent versions (PMBOK 8 issued in November 2025) have changed the basic structure, we have maintained the performance domains of the previous 2017 version to facilitate comparisons with the previous March 2020 assessment.

Approach and Methodology

Two key elements, referenced above, defined the steps taken to assess HONI's and the Peer Group Panel's project management execution from initial planning through to the commissioning or closeout activities:

1. *Maturity Rating Scale*, ranging from low ("Novice) to high ("Beyond Standards").

Figure I-1: Maturity Rating Scale (Illustrative Example)



2. *Ten Predefined Performance Domains*, to which the above Maturity Rating Scale was applied to define the maturity level (refer to Table I-1 on following page).

Table I-1: Project Management Performance Domains

Performance Domain	Description	Objective
Cost Management	Includes planning cost management, estimating costs, determining the budget, and controlling costs	Complete the project within a planned budget
Scope Management	Includes planning the management of scope, collecting requirements, defining the scope and creating the work breakdown structure, validating the scope and controlling the scope.	Control scope in a project and protect it against unmanaged scope creep
Schedule Management	Includes planning the management of the schedule, defining activities, sequencing activities, estimating activity resources, estimating activity durations, developing the schedule, and controlling the schedule	Complete a project on time
Resource Management	Includes planning the resource management process, acquiring the project team, developing the project team and managing the project team	Efficiently and effectively deploy people on projects
Risk and Contingency Management	Includes planning management of risk, identifying risks, performing qualitative risk analysis, performing quantitative risk analysis, planning risk responses, and controlling risks	Reduce the impacts of risks to the project once they occur
Quality Management	Includes planning the quality management process, performing the quality assurance process, and controlling the quality process	Ensure that the project meets its quality objectives
Contract Management	Includes planning procurement, conducting procurements, controlling procurements, and closing procurements	Management and coordination of purchasing activities in the project
Communications Management	Includes planning communications management, managing communications, controlling / disseminating communication, and stakeholder management (identifying stakeholders, planning stakeholder management, managing stakeholder management and controlling stakeholder management)	Keep all appropriate people informed of project / portfolio status and help manage the expectations of all project stakeholders (internal and external) during the project
Integration Management	Includes development of the project charter, developing the project management plan, directing and managing the project work, monitoring and controlling the project work, performing integrated change control and closing the project	Mechanisms and functions are in place to support the successful execution and delivery of the project
Technology Enablement	Includes use of enterprise-wide software and / or applications to facilitate effective management of the end-to-end project management process	Elevate and advance the workforce's performance of all processes outlined in the previous nine performance domains

NOTE: Technology Enablement is not reflected as a PMBOK Performance Domain but added due to the importance the proper application of technology will play in utilities achieving their vision for Project Management excellence.

For each Performance Domain, criteria were developed to assist in categorizing a utility's maturity level. Figure I-2 presents Schedule Management as an illustrative example with a more expansive discussion addressing the 10 Performance Domains provided in Appendix B.

Figure I-2: Schedule Management Maturity Rating Scale Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
Project schedules exist as separate and distinct items on individual laptops or hardcopy files, lacking any standards for the basic elements that constitute an integrated schedule. Slightly better than a punch list, the ability to identify and analyze schedule performance issues is largely dependent on SMEs.	Individual milestone and activity-level project schedules with inter- and intra-project dependencies are used to track and report progress on activities. Discussions are underway to implement an enterprise-wide solution to standardize methodology and reporting protocols.	Using a common schedule platform, uses a full hierarchy of schedules for each project / program that consider resource constraints when establishing start and completion dates. The schedule is viewed as the primary tool for quantitatively assessing progress. There is an appropriate level of rigor used to identify focus areas for mitigating the impact of any slippage in schedule.	Enterprise-wide resource-loaded schedule (single source of truth) is used to align the organization around the performance of work and strengthen coordination and communication among the various organizations. Strong emphasis on "protecting schedule," assigning defensible and trackable contingency, and applying analytics in reporting progress.	An improvement process is in place to continuously improve Schedule Management beyond Level 4. Lessons learned are captured and incorporated into existing processes.

Using these criteria as a guide, E Source conducted the interviews and completed surveys, asking questions and reviewing information / data to determine each utility's position on the Maturity Rating Scale across each Performance Domain.

These positions were converted to scores applying the following scale, noting that in instances where a utility straddled between two levels, the values were further refined to reflect its position on a continuum. Adding context to these scores, ratings above "3.5" suggests that the foundational elements are in place to successfully manage a significant capital investment portfolio.

Table 1-2: Scoring Table

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
1.5	2.5	3.5	4.5	5.5[3]

Once assigned scores, the basis for comparing HONI's performance in each Performance Domain was established, recognizing that benchmarking results are designed to provide directionally accurate insights, guiding decision-making and strategic planning while acknowledging that exact representation may vary.

[3] **A score of 5.5 would represent the upper bound of possible scores noting that 5.0 (bridging between Fully Integrated and Beyond Standards) was the highest score assigned to any of the utilities in this study.**

Performance Comparisons and Assessments

Applying the above approach and methodology and based on the study results relative to a Peer Group Panel of 14 electric utilities across North America, HONI is second quartile or better in 9 of the 10 performance domains and currently resides in the third quartile in Technology Enablement, which in its totality indicates that HONI meets the requirements to properly execute large capital plans. Table I-3 presents these results, indicating HONI's Maturity Rating Scale Score and its position relative to the Peer Group Panel within each Performance Domain.

Table 1-3: Performance Comparison

		Quartile			
Performance Domain	**Maturity Rating Scale Score**	**Bottom**	**3rd**	**2nd**	**Top**
Cost Management	4.50				
Scope Management	4.50				
Schedule Management	4.00				
Resource Management	4.25				
Risk and Contingency Management	4.00				
Quality Management	4.50				
Contract Management	4.50				
Communications Management	4.50				
Integration Management	3.75				
Technology Enablement	3.15				

Summary

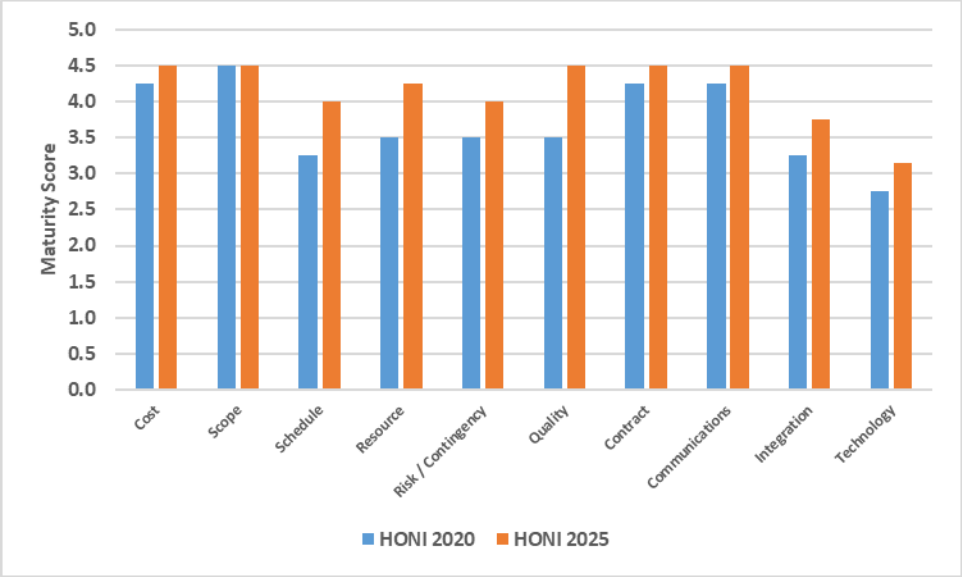
E Source notes both areas of strength and opportunities for improvement:

- *Areas of Strength*: The Transmission Capital Efficiency Initiative, developed in 2016 and rolled out in 2017 and the completed rollout and organizational acceptance of the Capital Delivery Model since the previous assessment (refer to FINAL REPORT dated March 2021), has continued to drive efficiency and ensure accountability throughout the process. Recognizing the emergence of larger and more complex projects often directed by external organizations HONI has taken steps to (1) account for the differing role of these external stakeholders in defining requirements, and (2) ensure that the key elements of HONI's project management process are scalable considering the extended planning and execution horizons. The previously conducted assessment cited strong focus on cost and resource management, rigorous project-based risk cost assessments, a disciplined approach to managing scope, and a well-defined gate process with clear expectations regarding the state of the design and accuracy of corresponding estimates. These efforts have yielded favorable results as increased maturity is noted in nine of the ten

performance domains, with the lone exception being Scope Management where HONI remains “Fully Integrated” (refer to Figure 1-3 below).

- *Opportunities for Improvement*: Acknowledging these favorable comparisons, E Source notes improvement opportunities remain:
    - Though HONI shows improvement in schedule, resource and integration management, work remains in tightening the closeout portion of projects (Integration Management) and providing consolidated resource-loaded project schedules (Schedule and Resource Management), and
    - Enhancements to HONI’s Information Technology (IT) platforms to replace fragmented legacy systems will aid in improving visibility of the analytics and resulting project management-related metrics.

Figure 1-3 : HONI 2020 / 2025 Performance Comparison



SECTION II - INTRODUCTION

Report Outline

In undertaking this study to examine HONI's management of transmission capital projects and arrive at the findings presented in the Executive Summary, E Source combined its industry perspective regarding project management (informed by several business process design efforts, practical "hands on" experience by E Source consultants, and insights gleaned from E Source facilitated Global Learning Consortia) with assessment frameworks / methodologies formed over 36 years of performing comparative analyses.

To establish context for the analyses and conclusions contained within this report, E Source:

- Reviewed relevant reports, procedures, and performance data provided by HONI,
- Was provided complete access to HONI's technical and management staff in the form of conference calls,
- Adopted the Project Management Institute's (PMI) PMBOK as the organizing framework around which to assess and compare HONI's management of transmission capital projects (***see Appendix B***), and
- Identified and recruited a Comparator Group (Peer Group Panel), comprised of 14 electric utilities, against which comparisons in executing projects could be made.

With this context established, E Source then assessed HONI's execution of its transmission capital project portfolio across 10 performance domains, from two perspectives, relative to:

1. An overall Maturity Rating Scale ranging from "novice" to "beyond standards," and
2. A comparator group of Canadian and U.S. utilities ("Peer Group Panel").

With respect to our knowledge and views of what constitutes best practices within each performance domain, E Source drew on observed best practices across the industry, as well as those exhibited by the Peer Group Panel.

The ensuing discussion expands upon these points and the conclusions stated in the Executive Summary:

- Section III – Project Approach: A more detailed description of and rationale for the approaches, methodologies, criteria, and frameworks adopted to accomplish the objectives of this study, and
- Section IV – Summary of Results: An expanded discussion of findings and conclusions, around the topic of project management.

Additional appendices are provided to supplement the information provided in this report in the form of comparative charts, graphs, and tables, as well as more in-depth explanations of the bases for our evaluations and supporting analytics.

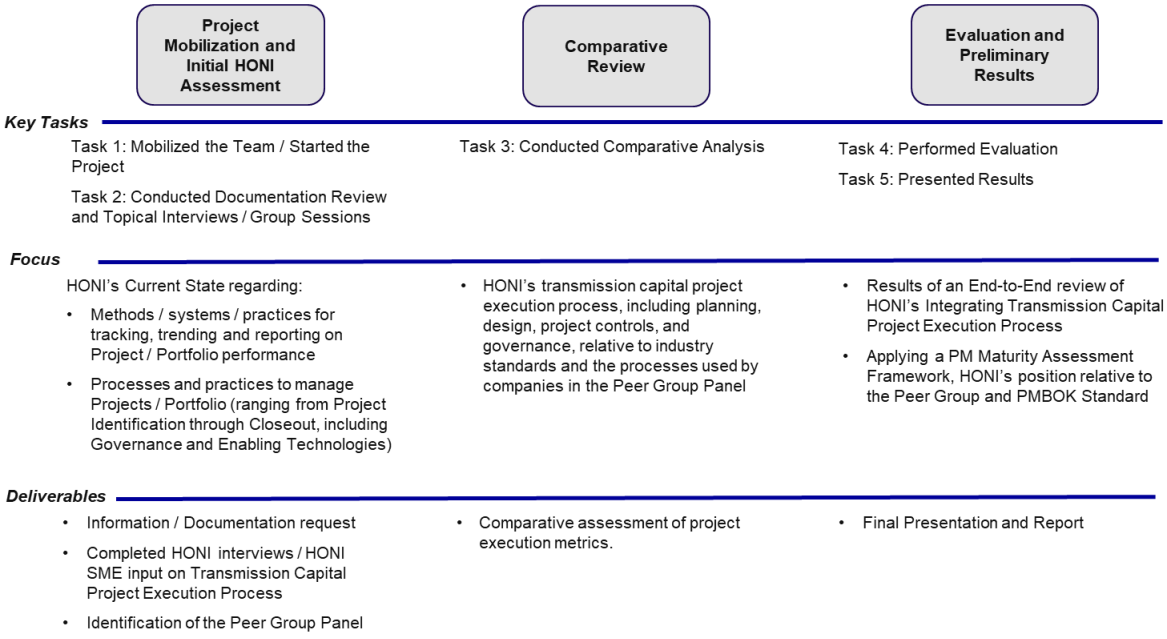
E Source Qualifications

E Source, headquartered at 1321 Upland Drive, Suite 3413, Houston, Texas, 77043, was retained as an independent expert. With over 36 years of experience conducting comparative performance assessments for the global utilities industry, E Source has supported multiple assessments and global benchmarking programs on six continents working with state and province public utility commissions as well as more than 300 electric, gas, and water utilities. E Source has augmented its analytical capabilities with a team of industry experts who are knowledgeable in best productivity and service-level performance practices to (1) ascertain an electric utility's efficiency and effectiveness in comparison to a qualified peer group panel, and (2) collaboratively develop aggressive, yet achievable performance improvement plans. Among other qualifications, E Source leads several Global Learning and Benchmarking consortia, which together with our portfolio of ongoing client engagements facilitates our ability to maintain "real-time" proprietary cost and operational performance data, correlated to industry "best practices," all supported by analytical frameworks built on the premise that industry "best performers" can be both efficient and effective. Appendix A provides additional details regarding E Source's qualifications and those of the subject matter expert assigned to this effort.

SECTION III – PROJECT APPROACH

E Source's approach, illustrated in Figure III-1 and further described below, was designed to evaluate HONI's performance in managing Transmission Capital Projects in comparison to a widely used industry standard and a relevant Peer Group Panel.

Figure III-1: Project Approach Overview



Through the three phases of the study, E Source performed five main tasks:

1. In mobilizing the team and starting the project, E Source defined the Assessment Framework and the Comparator Group ("Peer Group Panel").

2. Reviewed relevant documentation and interviewed 24 individuals, ranging from Superintendent to Vice President, and covering the organizations that play primary or key secondary roles in the execution of Transmission Capital Projects.

3. Conducted the review, applying an industry accepted standard for Project Management and comparing HONI's execution against a Maturity Rating Scale (absolute comparison) and processes / practices used by the Peer Group Panel (relative comparison).

4. Integrated insights gleaned from the review of documentation, interviews with HONI personnel, and surveys of the Peer Group Panel to determine HONI's position vis a vis Project Management.

5. Prepared a report and validated that our understanding of the facts leading to our assessment were correct.

The following discussion expounds on the key aspects of the approach and describes how they contributed to achieving an objective and meaningful evaluation.

Assessment Framework[4]

E Source adopted the framework outlined in the Project Management Institute's ("PMI")[5] Project Management Book of Knowledge ("PMBOK"), utilizing 10 performance domains (i.e., the scope of the assessment) around which to review HONI's project management processes. The team then established a Maturity Rating Scale, tailored to accommodate these 10 performance domains. In taking this approach, E Source was able to make two comparisons in parallel:

1. Absolute Comparison: Gauging HONI's standing relative to standards established by the PMI, and

2. Relative Comparison: Determining HONI's standing relative to a Peer Group Panel.

This approach allowed E Source to shape the focus of the interviews (within HONI and across the Peer Group Panel) and define criteria that assured a consistent and objective ranking of all parties.

The details of this framework are explained in Appendix B.

Comparator Selection

To execute the benchmarking, a comparator group of Canadian and U.S. utilities was developed ("Peer Group Panel") based on the following criteria:

- Operates and maintains Transmission assets,

- Has recently embarked on, or is implementing a project management improvement initiative,

- Has experienced / is anticipating a notable increase in transmission capital work, and

- Achieves an appropriate balance between Canadian and US utilities.

With these criteria in mind, E Source approached an initial list of 20 utilities to participate in the study and was able to obtain the participation of 14. Our experience has shown that this number of participants will provide meaningful results, and thus the resulting Peer Group Panel presented in Table III-1 represents a reasonable and valid comparison group for Hydro One.

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[5] **The Project Management Institute ("PMI") is the world's leading association for those who consider project, program, or portfolio management their profession. Celebrating its 51st anniversary in 2020, PMI has worked in nearly every country around the world to advance careers, improve organizational success, further mature the project management profession through globally recognized standards, certifications, resources, tools, publications, professional development courses and networking opportunities.**

Table III-1: Peer Group Panel[6]

American Transmission Company (ATC)	Louisville Gas and Electric / Kentucky Utilities*
ATCO Electric*	National Grid
Avista	NB Power
BC Hydro*	Newfoundland Power
DTE Energy*	Portland General Electric*
EPCOR (Alberta)	Public Service Electric and Gas*
FirstEnergy (OH, PA, and NJ Operating Companies) *	Yukon Energy

"*" denotes participation in previous study. Five utilities from previous study declined to participate (Evergy, Hydro Quebec, Pacific Gas and Electric, SaskPower, and Tennessee Valley Authority)

Normalization Factor Development

As this study is a review of practices (as opposed to outcome metrics / KPIs), there was no need to apply any normalization factors. The PMBOK standard is agnostic to the project and system demographic factors that typically affect comparisons between electric utilities.

Information Collection

Considering the decision to adopt a process / practices orientation in comparing HONI against the PMBOK standard and other Transmission Organizations, E Source took a real-time interactive approach to collecting information from HONI and the Peer Group Panel.

- In structuring the interviews within HONI, E Source presented a list of topics to which individuals have knowledge of their relative impact on Capital Project execution:
  - Project and Portfolio Management, Launch, Consolidation and Scoping
  - Project Management Functional Accountabilities and Process Workflow
  - Outage Coordination Services Framework
  - Field Execution Functions, Accountabilities and Process Workflows
  - Project / Portfolio Performance Tracking (leading and lagging indicators)
  - Resourcing Strategy and Planning
  - Contractor/Vendor Management
  - Portfolio and Project Risk and Contingency Management

[6] **Appendix C provides a summary of basic transmission system demographics for each of the Peer Group Utilities.**

- Transmission Projects (Scope, Cost, Staffing and Contracting)
- Strategic Planning (Focused on Environmental Strategy, Integrated Resource Plan, Impact of Renewables and DER - though minor given progress-to-date, Aging Infrastructure, and ever-increasing Customer Expectations)
- Technology Initiatives and Modernization (Impact of current and any new management, information, and operations support technology on HONI's ability to manage projects)
- Management and Labor Interface (Gain an understanding of the protocols, constraints and other factors relating to current Labor Agreements and any recommendations to resource any anticipated increase in project workload)

The results of these interviews served as a reference in determining HONI's absolute position on the Maturity Rating Scales.

- With respect to the Peer Group Panel, interviews were conducted, applying open-ended questions, thus providing sufficient information to ascertain current state across the 10 performance domains.

The following section presents the results of the study as well as commentary on the key elements that determined HONI's maturity scale rating across each of the 10 performance domains.

SECTION IV – STUDY RESULTS

Overall, Hydro One's Project Management practices compare well to the Peer Group Panel, as Hydro One is at the top two quartile levels in nine of the performance domains with Technology Enablement residing in the third quartile.

Figure IV-1: Summary of Peer Group Panel Comparisons

Performance Domain	Q4	Q3	Q2	Q1
Cost Management				▲
Scope Management				▲
Schedule Management			▲	
Resource Management				▲
Risk and Contingency Management			▲	
Quality Management				▲
Contract Management				▲
Communications Management				▲
Integration Management			▲	
Technology Enablement		▲		

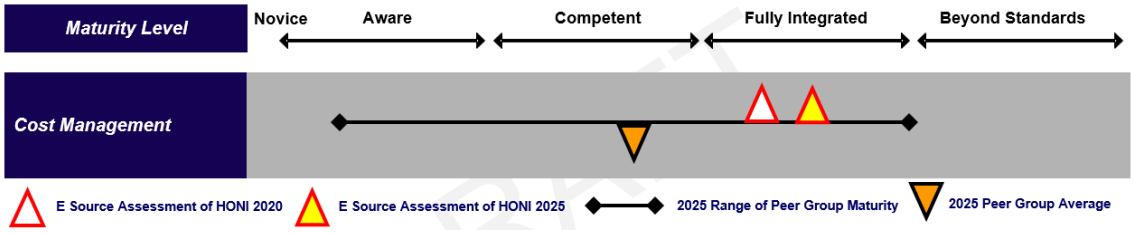
The following discussion portrays Hydro One's comparisons to the Peer Group Panel Averages, its maturity scale rating (past and present) and its relative positioning (quartiles) within each Performance Domain, accompanied by additional commentary to provide more context to the assessments.

Cost Management

Includes Planning Cost Management, Estimating Costs, Determining the Budget, and Controlling Costs.

Noting improvement since the previous assessment from 4.25 to 4.50 ("Fully Integrated") and continued top quartile performance, HONI's approach to managing project costs aligns with other industry leaders, continuing (1) execution of an effective project initiation / planning process, (2) prudent application of risk cost contingencies, (3) a well-defined stage gate process to guide the continual refinement of estimates, funding approvals, and supporting business cases, and (4) to provide variance analyses and actionable reports to Senior Management. Recent improvements include emphasis on improving efficiency (crew sizing and work practices such as crane vs. climb), applying value-engineering to provide optimum solutions and, for some larger projects, implementing an Early Contractor Involvement (ECI[7]) initiative to assure prudence in selecting optimum solutions and more reliable estimates during project execution. HONI has navigated the challenges posed by COVID-induced supply chain issues and corresponding increases in labor and material costs by tightening up its management of contingencies and adjusting project timelines to accommodate the realities of extended delivery times of major equipment.

Figure IV-2: Cost Management Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
4.25	4.50	Top Quartile

Scope Management

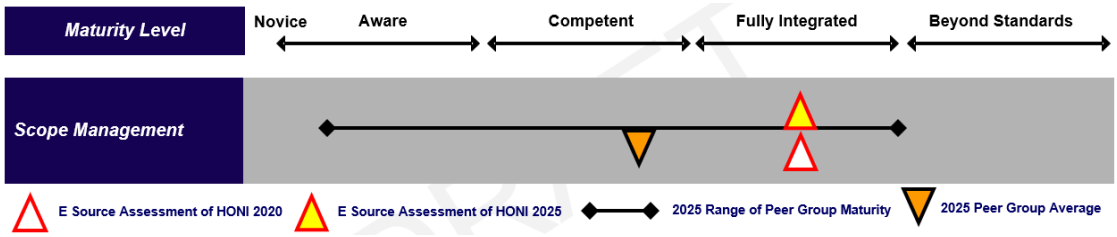
Includes Planning the Management of Scope, Collecting Requirements, Defining the Scope and Creating the Work Breakdown Structure, Validating the Scope and Controlling the Scope.

Noting the same rating as that from the previous assessment of 4.50 ("Fully Integrated"), HONI's approach to managing scope continues to exceed that exhibited by the Peer Group Panel (i.e., top quartile performance). The stage gate process[8] leading to the establishment of a project baseline when engineering is approximately 30 percent complete, linkage of risk contingencies to the scoping and estimating discussion, and the advent of coordination meetings between planning, construction, engineering, and operations (including front-line supervision) early in the

[7] **The Early Contractor Involvement (ECI) approach involves the hiring of two EPC contractors during the initial phases of a project where the deliverables are used to competitively award a fixed-price contract.**
[8] **HONI is also working to incorporate more flexibility (less rigidity) into the stage gate process to account for varying levels of complexity and costs of projects, in and of itself sound industry practice.**

process are indicative of "best practices," and substantiate HONI's status as "Fully Integrated." This assessment is further reinforced by the previously presented ECI for some larger projects where active EPC contractor involvement in the initial phases of the project promotes greater understanding of the proposed solutions, perspectives of various stakeholders, and any embedded risks.

Figure IV-3 : Scope Management Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
4.50	4.50	Top Quartile

Schedule Management:

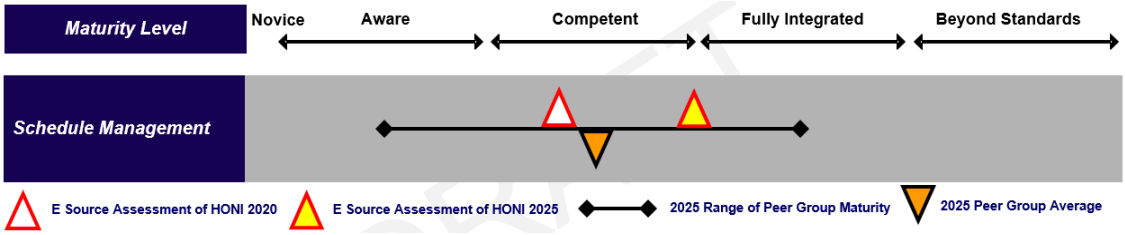
Includes Planning the Management of the Schedule, Defining Activities, Sequencing Activities, Estimating Activity Resources, Estimating Activity Durations, Developing the Schedule, and Controlling the Schedule.

Noting improvement since the previous assessment from 3.25 to 4.00 and a corresponding improvement in comparative rating from median to second quartile, HONI's rating between "Competent" and "Fully Integrated" in schedule management is based on the following:

- Sound mechanics of scheduling (e.g., establishing a hierarchy of schedules, developing activity networks, and estimating durations),
- Deployment of an IT enabling platform (P6 software solution),
- Inclusion of Commissioning activities,
- Addition of field schedulers to better align the field with the Project Management / Controls function,
- Application of Early Contractor Involvement (ECI) initiative for some larger projects,
- Addition of the Stations Commissioning Coordinator (SCC) role to smooth the transition from execution to commissioning,
- Ability to work to system planned outages,
- Adoption of "rolling wave" concept to account for scoping uncertainty comport with an industry practice, and
- Recent progress in developing resource-loaded activity-based schedules (implemented for projects in progress and in development for projects in planning).

However, in addition to continuing towards achievement of full integration between scheduling, cost and resources, applying further rigor in reporting progress (e.g., earned value or percentage complete in addition to current approach which is conservatively milestone-based) remains as an opportunity for improvement.

Figure IV-4: Schedule Management Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
3.25	4.00	Second Quartile

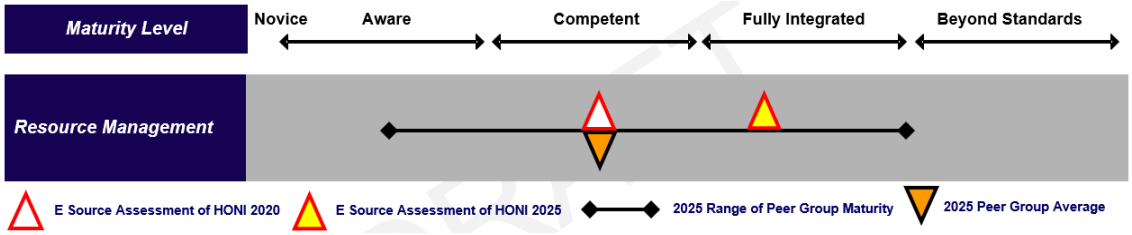
Resource Management

Includes Planning the Resource Management process, Acquiring the Project Team, Developing the Project Team and Managing the Project Team.

Noting improvement since the previous assessment from 3.50 to 4.25 (approaching "Fully Integrated") and continued top quartile performance, HONI remains effective in accounting for the critical resources necessary to deliver transmission capital projects, establishing communication and coordination channels to ensure the resource pools (Engineering, Station Operations, Station Construction, Line Construction, and Project Management) are responsive as the projects progress through to execution and commissioning, maintaining an optimal mix of in-house and contract labor to flex with the workload. Assimilation of new staff is facilitated by the existence of an effective Trade School and continued focus on training and mentoring. Strengthening of the current matrix structure in clarifying roles and responsibilities represents an opportunity for improvement and advancement towards "Fully Integrated" status.

The recently developed Transmission and Stations Integrated Resource Forecast (TSIRF) tool provides an integrated approach to resource planning, replacing the previous use of multiple tools across HONI. This cohesive solution provides a consistent approach and assumptions across all lines of business (Stations Construction, Transmission Lines, Commissioning, Engineering, Project Delivery, and Environmental), forecasting the resources (both internal and external) required to execute each project / program.

Figure IV-5 : Resource Management Comparisons



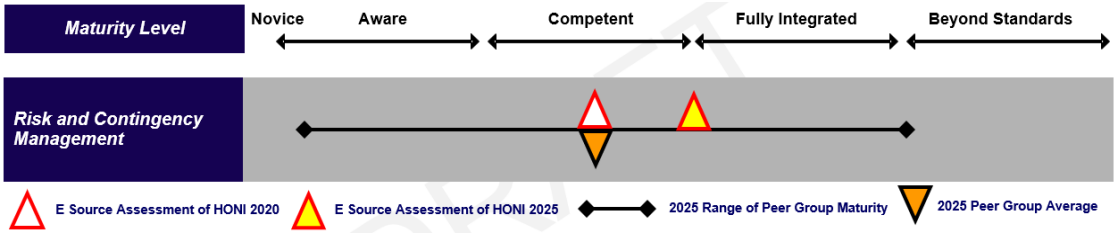
Maturity Score		Comparative Ranking
2020 Score	2025 Score	
3.50	4.25	Top Quartile

Risk and Contingency Management

Includes Planning Management of Risk, Identifying Risks, Performing Qualitative Risk Analysis, Performing Quantitative Risk Analysis, Planning Risk Responses, and Controlling Risks.

Current state places HONI between the "Competent" and "Fully Integrated" categories and in the second quartile in comparison to the Peer Group Panel, with noted improvement in the areas of (1) identifying and managing contingencies (i.e., more specificity in assigning / tracking risks to scheduling and cost uncertainties), and (2) through Risk Workshops, fully operationalizing the use of Risk Registers in communicating status / driving closure of any mitigating actions. Having adopted the key processes that define effective Risk Management (i.e., Identification, Analysis, Evaluation, and Treatment of Risks), HONI is poised to adopt a more holistic view of risk at the project and portfolio levels (as compared to specific gates within the project management framework).Though the maturity ratings have improved from 3.50 to 4.00 (between "Competent" and "Fully Integrated"), the comparative ratings have slipped slightly from between top and second quartile to second quartile. Not reflective of a slippage in actual performance, this change is attributed to the increased industry focus on risk and contingency management and the dynamics of a differing peer group panel.

Figure IV-6: Risk and Contingency Management Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
3.50	4.00	Second Quartile

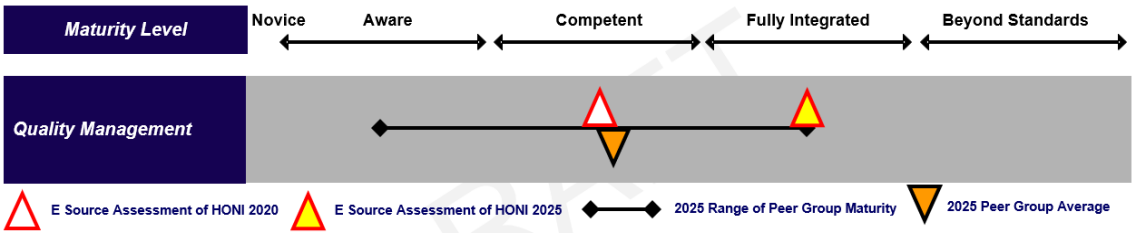
Quality Management

Includes Planning the Quality Management Process, Performing the Quality Assurance Process, and Controlling the Quality Process.

Noting improvement since the previous assessment from 3.50 to 4.50 and a corresponding improvement in comparative rating from second to top quartile, HONI's rating of "Fully Integrated" with a comparative position in the top quartile in this performance domain is based on the effective integration of its QA / QC processes, and readiness to assume a more authoritative role:

- Hydro One has an established Quality Management System (QMS) integrated into the full lifecycle of a project, including vender selection, installation, and asset readiness, one that is not limited to individual activities, but focused on minimizing rework, overspending, and schedule delays while ensuring long-term safe, compliant, and reliable asset performance:
    - The vendor pre-qualification process ensures that the most capable suppliers with appropriate competencies and performance histories are engaged.
    - Definition of quality expectations, hold points, and acceptance criteria that are contractually enforceable.
    - For larger projects, a peer review of all designs is conducted prior to issuance with an emphasis on compliance with specifications and design standards.
    - There are pre-service and station testing guides that define the minimum testing, verification steps, and acceptance thresholds prior to energization.
    - A Project-Specific Quality Plan (PSQP) addresses risks, asset types, standards, and regulatory obligations unique to each project.
- HONI confirms adherence to the approved quality plans and the commissioning activities validate that all newly installed assets function as intended and meets applicable operational requirements. Further, experienced field inspectors are deployed to monitor quality, progress, and safety throughout a project, with strategically established checkpoints to ensure timely identification of any deficiencies / oversights during execution.
- The inspections and any noted deficiencies are stored on a central SharePoint site supporting HONI's continued emphasis on continuous improvement and knowledge sharing.

Figure IV-7: Quality Management Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
3.50	4.50	Top Quartile

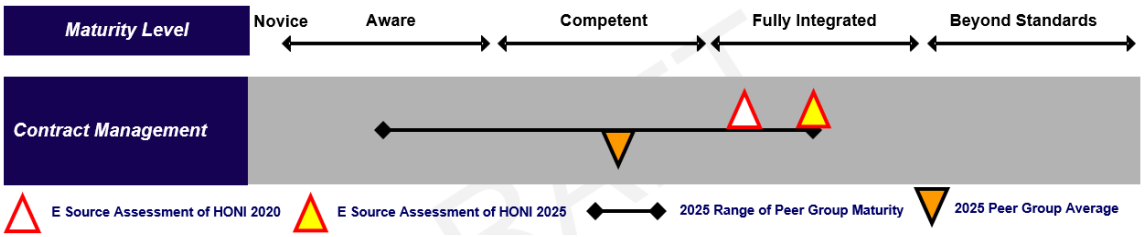
Contract Management

Includes Planning Procurement, Conducting Procurements, Controlling Procurements, and Closing Procurements.

Noting improvement since the previous assessment from 4.25 to 4.50 and continued top quartile performance HONI has advanced to a "Fully Integrated" rating, starting with the formation of a dedicated group, tasked with clarifying roles and responsibilities and standardizing project administrative requirements. Specific observations leading to this improved rating include:

- Categorization of outsourced projects based on level of complexity, thus de-risking the process via the proper assignment of contractors and clarifying the required level of rigor in preparing Requirements Definitions and RFPs,
- Maintaining a contingent of qualified contractors, fully conversant with HONI's requirements and vested in its success and for the larger projects, instituting multiple contractors during the planning phases to (1) increase the likelihood of an accepted solution, and (2) drive performance based on competition during actual execution,
- Implementing a performance management process for engineering contracts, requiring input from all key stakeholders, milestone tracking of deliverables, and in-process and post-project performance review meetings. In so doing, HONI can provide timely feedback, resolve issues during a project and perform a holistic assessment of performance and qualification for the supplier to provide services in the future, and
- HONI continues to anticipate and procure long-lead time equipment in support of project schedules.

Figure IV-8 : Contract Management Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
4.25	4.50	Top Quartile

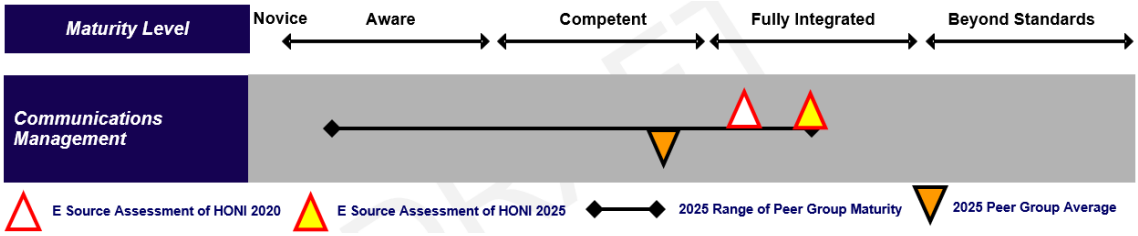
Communications Management

Includes Planning the Communications Management, Managing Communications, Controlling / Disseminating Communication, and Stakeholder Management (Identifying Stakeholders, Planning Stakeholder Management, Managing Stakeholder Management and Controlling Stakeholder Management).

Noting improvement since the previous assessment from 4.25 to 4.50 ("Fully Integrated") and continued top quartile performance HONI is effective in managing communication within the project and with key internal and external stakeholders:

- The stage gate process itself provides a reporting regimen and cadence to strategically manage and communicate status across the organization,
- There exists a well-defined protocol for tactically reporting project performance and providing greater visibility of any changes with appropriate thresholds for escalation to Executive Management,
- During the initial stages of a project there is active internal stakeholder engagement (and in the case of the larger projects external stakeholder engagement) to address issues such as constructability, operability, maintainability, safety, and any environmental factors,
- Bi-weekly meetings, two-week look backs / look ahead, and monthly reviews drive alignment between field execution, project managers, and commissioning, and
- Community Relations continues to play a role throughout a project, holding Public Information Center (or other forms of outreach) as appropriate and acting as a Single Point of Contact for the community and public officials.

Figure IV-9: Communications Management Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
4.25	4.50	Top Quartile

Integration Management

Includes Developing the Project Charter, Developing the Project Management Plan, Directing and Managing the Project Work, Monitoring and Controlling the Project Work, Performing Integrated Change Control and Closing the Project.

Noting improvement since the previous assessment from 3.25 to 3.75 and a corresponding improvement in comparative rating from median to second quartile, HONI has achieved a rating of "Competent" and approaching "Fully Integrated":

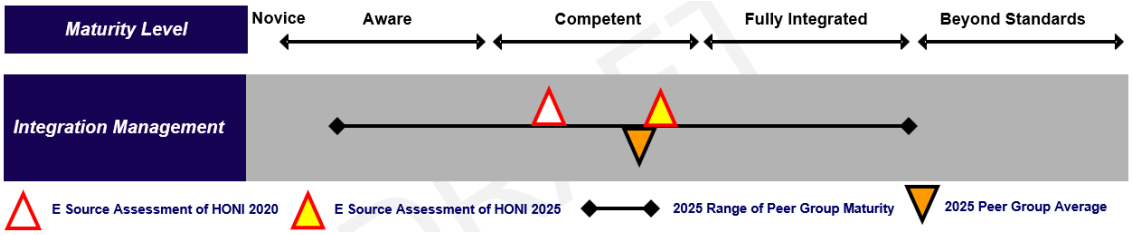
- HONI effectively manages the trade-offs between cost, schedule, and quality, albeit still requiring a significant amount of manual intervention to compensate for lack of fully integrated IT enabling technologies,
- HONI has instituted a Project Management Excellence Quest or "PMEQ" to assess the extent to which Project Managers are focusing on the right things and doing these things well, further reinforcing role clarity within the Transmission Capital Delivery Model and supporting the integration of cost, schedule, and quality in executing projects,
- The Capital Delivery Model ("CDM") has been fully implemented, and has gained acceptance / its value is recognized,
- Project Managers have been assigned responsibility to develop business cases, thus establishing their ownership for the results,
- Capital Delivery Planners (CDPs) have been deployed to improve integration between planning, engineering, and construction, (1) providing for more complete and actionable work plans, better planning (scope-based scheduling and alignment of estimates, work plans, and timelines) and forecasting, (2) influencing design, constructability, safety, risk and contingency planning decisions, and (3) tracking any deviations / integrating lessons learned for purposes of continuous improvement.

- In initiating larger scale / extended projects, HONI has been effective in maintaining (yet adjusting for scalability) the Stage-Gate process,

- Though improvement is noted in addressing high-priority field-marked prints, as noted across the industry, the proper closing out of projects and associated update of all relevant documentation remains a challenge, and

- Though cross-functional collaboration has improved, particularly with the introduction of the CDP, clarity of roles and responsibilities across the functions that comprise the matrix structure (e.g., Project Delivery, Planning, Contracts, Asset Management, Engineering, Environmental, Regulatory, Construction, and Commissioning) remains an opportunity to strengthen the overall execution of projects.

Figure IV-10: Integration Management Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
3.25	3.75	Second Quartile

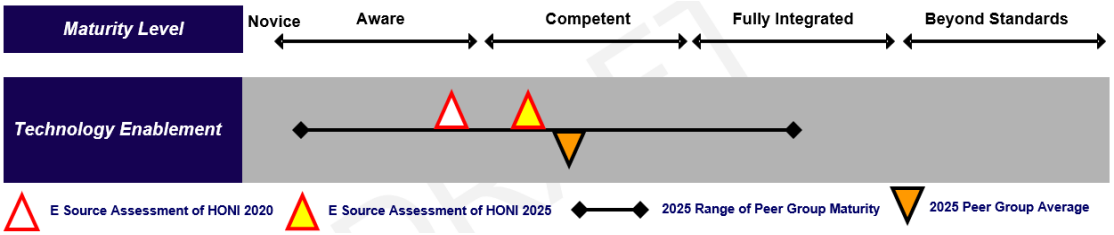
Technology Enablement

Includes use of enterprise-wide software and / or applications to facilitate effective management of the end-to-end Project Management process.

Noting improvement since the previous assessment from 2.75 to 3.15, a corresponding improvement in comparative rating, from straddling the third and fourth quartile to third quartile in comparative rating, and achieving an initial rating of "Competent", Technology Enablement remains HONI's biggest opportunity to improve. Noting that HONI is moving towards a more integrated approach to cost, schedule, and resource tracking (refer to the TSIRF discussion under Resource Management) and centralized data / information repositories and has deployed Power BI as an improvement over excel in supporting portfolio reporting and SAGE to centralize inputs into the estimating process, specific observations contributing to this current state assessment include:

- Lack of a robust Project Cost Accounting platform to automate the management and reporting of cost data and provide greater visibility of the analytics behind the metrics,
- Underutilization of its industry embraced P6 scheduling platform to develop resource-loaded schedules and more fully integrate the engineering, construction, and commissioning activities, and
- Reliance on manually prepared project risk registers, rendering any effort to aggregate project risks, develop corresponding risk-related metrics, and identify trends difficult.

Figure IV-11: Technology Enablement Comparisons



Maturity Score		Comparative Ranking
2020 Score	2025 Score	
2.75	3.15	Third Quartile

APPENDIX A – E SOURCE QUALIFICATIONS

E Source, the acquirer of previously engaged UMS Group, delivers outcome-based consulting, data science, and research services exclusively for the utility industry. Since 1986, it has provided services on a variety of projects for more than 500 electric, natural gas, water, wastewater, and multi-service utility clients—helping to transform operations, enhance efficiency, and adapt to evolving industry demands. With a corporate commitment to practical innovation, we deliver nearly four decades of utility-focused service through a broad and unique range of capabilities within three core practices: Consulting (focused on utility transformation), Data Science (turning utility data into clear decisions), and Research and Advisory (including data-backed insights, benchmarking, and expert advice to assist utilities in optimizing performance, reducing risk, and seizing opportunities.

In integrating UMS Group into its organization, E Source adopts the position of the leading provider of utility benchmarking services, starting with UMS Group's initial Benchmarking and Best Practice Consortia in 1990 (PACE - Performance and Competitive Excellence), and its established position as a global leader in electric industry multi-company assessment and benchmarking studies. Key differentiators in our performance assessment approach are (1) the depth of our understanding of industry best practices to drive operational performance, and (2) benchmark programs that define current best practice productivity and service level performance in all major functional areas. Demonstrating the breadth of our experience, we have performed engagements on *six continents* with more than *300 companies*.

E Source's performance database developed and maintained over the past 36 years and its E Source-facilitated industry consortia of leading Generation, Transmission, and Distribution companies around the world provide significant insights into the drivers of best practices and resulting top quartile service and cost level performance.

Experience Summary of Project SME – Jeffrey W. Cummings

Mr. Cummings has over 45 years of professional consulting experience, with an extensive background in engineering, strategic and operational planning for vertically integrated investor-owned utilities and municipalities in North America and Asia Pacific. His most recent engagements include projects for Hydro Ottawa, Portland General Electric, Lansing Board of Water and Light, AES-Indianapolis Power and Light Company, Pacific Gas and Electric, FirstEnergy (Ohio, West Virginia, Maryland, New Jersey, and Pennsylvania), NIPSCO (Gas), ATCO Electric, Saskatchewan Power, Ameren (Illinois and Missouri), Ergon Energy, Toronto Hydro (THESL), and Public Service Electric and Gas Company. He has supported the industry in addressing (1) key strategic and operational challenges related to system modernization, (2) system cost and service level performance through comparative analyses (benchmarks) and the integration of industry best practices, (3) project and portfolio management, (4) reliability and risk mitigation, (5) energy efficiency, (6) fleet optimization, (7) capital investment planning and prioritization, (8) asset risk strategy and plan development, (9) organizational transformation, and (10) regulatory strategy. When called upon, he has offered expert testimony and/or opinion, most

recently for two Canadian Provincial Utilities, one Mideast Utility and for four US Investor-owned utilities operating in Kansas, New Jersey, Ohio, and Pennsylvania.

Earlier in his career, he held a series of engineering leadership positions at Vectra Technologies (formerly Pacific Nuclear and a publicly traded nuclear services company) and ultimately became Vice President of Nuclear Engineering. In that capacity, he served as the profit/loss manager for over 425 professional engineers across five regional offices in the U.S. In performing this role, he actively engaged in formulating strategies for customer development, product/service expansion, business consolidation, and oversaw the management of over 500 projects annually for approximately 75 percent of the U.S. nuclear utilities. Prior to his tenure with Vectra Technologies, Stone and Webster Engineering Corporation employed Mr. Cummings where he assumed increasing levels of responsibility in the management of large Lignite and Nuclear Power engineering and construction projects, culminating as Project Controls Manager for the completion of the last U.S. commercial nuclear power generating station (Clinton Power Station).

Mr. Cummings holds an M.S. degree in Operations Research from the U.S. Naval Postgraduate School and a B.S. degree from the U.S. Naval Academy at Annapolis, Maryland

Highlights of Directly Relevant Experience

Most recently supported the pre-commencement activities related to LUMA's takeover of the Puerto Rican Electric Power Authority (PREPA), conducting a gap assessment of its T&D Operations focused on Reliability, System Resiliency, Major Event Management, Asset and Work Management, Technical Services, Materials Management, and Fleet, supporting Regulatory in the development of the System Remediation Plan, and establishing the procedural / process infrastructure for its Asset Management function. Mr. Cummings provided oral testimony during the Technical Conferences leading up to Commencement and is currently assisting in the implementation of LUMA's Asset and Work Management Practices.

Assisted a Mid-Atlantic's Utility in its initiative to operationalize its Investment Delivery Assurance function in achieving two key outcomes: (1) Project and Work Execution to pre-established schedule, budget, and quality requirements and (2) verifying the extent to which any value and / or risk mitigation benefits ascribed to specific projects / programs are realized (indicative of capital investment and O&M spending portfolios that are or are not in alignment with Asset Management and Enterprise strategies – SAMP, AMPs, etc.).

- Project and Work Execution: Establishing priorities and coordinating activities among operations, maintenance, contractors and supporting functions, identifying and evaluating possible differences in productivity of outside contractors and in-house staff, inconsistencies in providing "as-built" drawings upon completion of a project, tendency to match workload to available staff rather than establish a staffing strategy based on system / asset requirements, management of project and schedule contingencies, post-project reviews, and barriers resulting from organizational silos during execution.

- Value and / or Risk Mitigation Realization: Determining and communicating the total impact of capital investment and O&M spending portfolios to all stakeholders. This

required an approach and supporting framework that calculates, and aggregates projected benefits of an entire portfolio.

In support of a Canadian Utility's rate filing application, performed a Unit Costs Benchmarking Study aimed at reviewing how the utility determined the unit costs underlying its distribution system capital and operational programs, performing benchmarking comparisons with a selected peer group of utilities in Canada and the United States, and providing recommendations on how the utility can improve its unit costing practices in the future.

Supported development of an Northeastern Utility's 5-year Base Capital Budget, providing justification for each element, complete with detailed supporting analysis and benchmarks where needed and appropriate, quantifying the impact of planned Clause and Blanket spend, as well as specific named Capital projects on anticipated asset failure rates and the resulting need for spending of each Capital Blanket, challenging and testing the logic and rationale for options considered and choices made for spend levels proposed, and creating a coherent narrative to explain the reasons and justification for major amounts involved and variances from previous plans, helping the utility harness their historical data on costs, workload volume and unit rates to clarify assumptions regarding cost drivers behind projections of Capital Spend in each area for each year looking forward over the 5 years, and providing support in the design / development of a presentation of the 5-year Capital Budget for Executive Management review.

Supported the filing of a Midwest Utility's T&D Grid Modernization and Resiliency Plan, identifying and analyzing the rationale for and wide-ranging implications of the Plan on the Company and its customers. Noting that the utility is committed to investing as wisely as possible on its customers' behalf, the final report provides transparency to the proposed investments and decisions driving their selection, quantifying the benefits (most notably those pertaining to reliability) in terms of improved performance or avoided risks.

Developed an Asset Management Plan for an Eastern Utility, addressing gaps that preclude its designation as competent across all elements that define an effective Asset Management system. Applying the ISO 55000 criteria, the resulting plan laid out a plan to achieve this level within three years, with identified / budgeted initiatives and a performance dashboard, against which progress can be measured.

Conducted an enterprise-wide review of a mid-western electric and water municipality to corporate organization structure considering pre-established strategic goals and six major initiatives, all geared towards its vision as a Utility of the Future. Included was the establishment of a Project Office for a new CCGT plant, the planned retirement of a coal-fired station, four major IT / OT initiatives, considerations regarding aging workforce and the attending opportunities to retool its staff, a mandate to reduce O&M spending by 15 percent, all within the construct of managing risk during a major industry transformation. His efforts included detailed analyses of staffing levels, worker productivity, O&M program execution, and capital efficiency, benchmarking cost, and service level performance, and identifying industry best practices to close identified performance gaps, Recommendations were presented and accepted by the utility (with minor adjustments) and is in the process of extending the contract to include implementation support.

Worked with a west coast electric utility in establishing a Project and Portfolio Management function. Starting with defining criteria for evaluating and selecting projects for execution, the process framework put in place provided the governance and operating guidelines to manage a portfolio and specific projects throughout the fiscal year, establishing the concepts of "contingent" projects, the capture of value, risk mitigation and transparency in comparing the value of electric production and energy delivery investments.

Supported a mid-western electric utility's rate case, testifying to the veracity of its asset, risk, and performance management programs and efforts underway to address significant challenges with its central business district underground network system. Consistent with Mr. Cummings' recommendations, he participated in a collaborative effort to define an oversight process that focuses on a comprehensive performance dashboard of KPIs and monitoring progress towards an Industry Leading Asset Management process.

Spearheaded efforts to provide third party assessments of a mid-Atlantic electric utility's capital investment, O&M spending levels and service level performance in support of a base rate filing; and later assessed the prudence of decisions made in the events leading up and during three extraordinary storm events during the 2011 - 2012 timeframe. He led a comprehensive benchmarking effort, focused on productivity (unit cost), reliability, and storm restoration performance. In both instances, he provided written direct and oral testimony during cross-examination demonstrating the utility's effectiveness in balancing operational performance, cost, and risk mitigation.

Assisted a mid-western utility in developing a System Revitalization Program for submittal to its Board of Directors and State Regulator. The proposed plan provided profiles of projected capital and O&M cash flows, the capture of utility and customer benefits and risks, and an industry context around which to justify such a program. The results of this effort were entered testimony in support of the utility's filing for a capital rider, for which it received sufficient funds to support the initial 18 months of a 10-year program.

Assisted a Canadian utility in offering an independent third-party assessment of a recent PBR filing performing high-level comparative analyses (benchmarks) of proposed growth and capital investments geared towards infrastructure renewal over a 5-year period; and assessing the risk of returning to previously established lower capital investment plans. This effort included providing testimony as part of a formal hearing with the Provincial Utility Commission.

Served as Project Director for a full-scale business renewal effort, establishing a plan to improve the efficiency of capital investments, and decrease O&M spending by $50 million annually without any noted decrease in system performance or increase in operational risk. Conducted across the entire enterprise with a focus on worker productivity (O&M program unit costs), capital efficiency (capital investment portfolio and unit cost management), this effort launched a series of initiatives that over 10 years will decrease spending levels by a cumulative $500 million and set the stage for transitioning to the Utility of the Future. Areas of focus included comparative cost and service level analyses, work planning and execution, performance dashboards, transmission and distribution reliability, capital portfolio optimization, and business value/risk tolerance frameworks;

and addressed the necessary infrastructure to construct a “first-of-its-kind” carbon capture generating facility.

Performed a capital and O&M spending and risk mitigation diagnostic for a mid-level Midwest utility in support of an overall business case to infuse more capital into its transmission and distribution infrastructure. The case was compelling enough to present to the Board of Directors and the Commission State and will be a cornerstone for subsequent strategic planning and future rate filings.

Supported a mid-level Midwest utility in its energy efficiency/demand response filing with the state regulatory and governing entities. Applied industry comparative analyses in demonstrating value capture / risk avoidance for all stakeholders (investors, customers, and utility) and validated that the proposed program met the intent and letter of the legislative mandate.

Conducted an enterprise-wide capital efficiency assessment for a Canadian Utility spanning electric transmission and distribution and electric generation. In reviewing their planned capital expenditures over a 10-year period, Mr. Cummings led the analyses of worker productivity (unit cost) and capital project execution and developed a plan to (1) reduce the current planned capital expenditures by 25 percent and (2) optimize the allocation of capital over the 10-year planning horizon with due consideration to optimizing the trade-offs between value and asset risk.

Strategic advisor for a major transformation effort within a U.S. Midwest electric and water municipality, that included conducting performance diagnostics (benchmarks) of its engineering and production divisions, development of a work planning and outage management program (and support processes), and several initiatives focused on achieving organizational alignment. Supporting efforts included oversight of the completion of a CCGT Plant (including supporting negotiations with GE for a LTSA), establishing criteria and process for the converging IT/OT, and the creation of an Organizational Efficiency and Effectiveness model.

Led the implementation of a process (and supporting software) to optimize the capital spending profile across three operating companies within a large US-based electric and gas company (electric transmission and distribution, gas transmission, distribution and storage, fleet, and electric generation); as well as one of the largest gas utilities in the US Midwest. In performing these projects, Mr. Cummings facilitated the linkage of the proposed investment’s value and its contribution to overall corporate strategy as well as the risk that a specific investment should be deferred; and equally important, implemented the process in a manner that garnered organizational support for change.

Participated in a task force and subsequently joined the implementation team in developing and executing a five-year plan to revamp the electric transmission and distribution infrastructure for the Chicago business district. This effort involved the translation of highly technical specifications and detailed budgeting information into terms easily understood by commission staff, city government, and the utility’s customers. All external stakeholders (i.e., Board of Directors, City of Chicago, Commission Staff and State Regulator accepted the plan. While supporting implementation, Mr. Cummings developed the strategies and plans for initially routing, certifying,

designing, and installing 135kV and 345kV transmission to meet projected load growth and system reliability requirements. He played a key role in shortening the certification period by as much as 50 percent. This required effective liaison and communication with the Illinois Commerce Commission and Army Corps of Engineers as well as coordination of Commonwealth Edison's engineering and construction organizations and their assigned "contractors of choice."

Worked in a variety of capacities for a nuclear engineering consulting company, serving initially as a Project Manager and ultimately as the Vice President of Nuclear Engineering. Over this 11-year period, he played a major role in growing annual revenues from $5.0 million to $50.0 million while increasing market penetration to approximately 75 percent of the US nuclear utilities. He developed many of the skills and competencies used in his roles as management consultant (summarized above) through his hands-on experience in managing over 425 engineering professionals and overseeing the management of over 500 projects annually.

Worked in a variety of capacities for Stone and Webster Corporation, primarily assigned to major nuclear power plant design and construction projects. Specific assignments included:

- Assignment to the Beaver Valley Power Station project, establishing a projects control process and system within the Duquesne Light Company to manage the installation of Three Mile Island modifications in support of the second refueling outage, improving actual performance in terms of work performed and schedule duration from the initial refueling outage by a factor of three. Following this effort, Mr. Cummings shifted his focus to the unit under construction (unit no. 2) where he installed a process to facilitate the final turnover of the systems (and accompanying documentation) to plant operations over an 18-months period.

- Assignment to Clinton Power Station, where he acted as Project Controls Manager for the contractor, facilitating the lifting of 12 Nuclear Regulatory Commission (NRC) imposed stop work orders and subsequent construction and turnover of the plant to the Illinois Power Company (IPC). Key activities over a two-year period included a successful Fuel Load Caseload presentation to the NRC, rate case preparation, an information system installation to track the turnover of all systems and instituting an integrated cost and schedule process and system to support weekly and monthly reporting to project and IPC executive management. His role in integrating the construction and system turnover schedules (and subsequent development of computerized detailed system turnover punch lists) served as a primary catalyst for successful completion of the Clinton Power Station project.

Served in the U.S. Navy in increasingly responsible roles culminating as a Weapons Officer on a destroyer, USS Robert E. Peary (FF-1073). In this capacity, he managed and led three divisions totaling 100 sailors, responsible for the maintenance and operation of all weapon and detection systems, the major equipment necessary to support basic seamanship evolutions, and daily consumables for the entire ship's force. He left the U.S. Navy in 1980, having earned the Navy Achievement Medal for his efforts during two extended deployments and extraordinary performance in the areas of Anti-Submarine Warfare and Naval Gunfire Support.

APPENDIX B – PROJECT MANAGEMENT EVALUATION FRAMEWORK

The Project Management Evaluation Framework applied for this study reflects a combination of the:

- 10 Performance Domains, nine of which define the focus of the Project Management Book of Knowledge (PMBOK), recognized as a fundamental resource for project management in any industry, and

- Maturity Scale Rating Criteria to assure consistency in identifying any major process / practices gaps and translating them into scores / ratings that connote competency level within a specific area / function in the business.

PMBOK – Informed Performance Domains

Table B-1 (following page) summarizes the 10 Performance Domains, against which E Source assessed HONI's relative maturity scale rating and compared its performance to the 14 electric utilities that comprised the Peer Group Panel.

Table B-1: Project Management Performance Domains

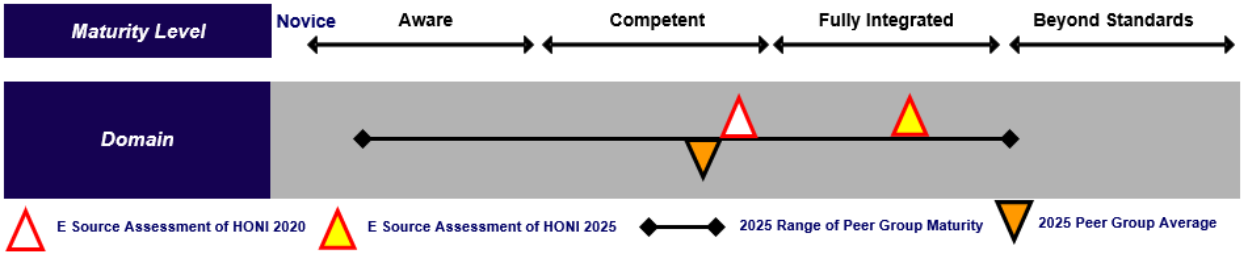
Performance Domain	Description	Objective
Cost Management	Includes planning cost management, estimating costs, determining the budget, and controlling costs	Complete the project within a planned budget
Scope Management	Includes planning the management of scope, collecting requirements, defining the scope and creating the work breakdown structure, validating the scope and controlling the scope.	Control scope in a project and protect it against unmanaged scope creep
Schedule Management	Includes planning the management of the schedule, defining activities, sequencing activities, estimating activity resources, estimating activity durations, developing the schedule, and controlling the schedule	Complete a project on time
Resource Management	Includes planning the resource management process, acquiring the project team, developing the project team and managing the project team	Efficiently and effectively deploy people on projects
Risk and Contingency Management	Includes planning management of risk, identifying risks, performing qualitative risk analysis, performing quantitative risk analysis, planning risk responses, and controlling risks	Reduce the impacts of risks to the project once they occur
Quality Management	Includes planning the quality management process, performing the quality assurance process, and controlling the quality process	Ensure that the project meets its quality objectives
Contract Management	Includes planning procurement, conducting procurements, controlling procurements, and closing procurements	Management and coordination of purchasing activities in the project
Communications Management	Includes planning communications management, managing communications, controlling / disseminating communication, and stakeholder management (identifying stakeholders, planning stakeholder management, managing stakeholder management and controlling stakeholder management)	Keep all appropriate people informed of project / portfolio status and help manage the expectations of all project stakeholders (internal and external) during the project
Integration Management	Including developing the project charter, developing the project management plan, directing and managing the project work, monitoring and controlling the project work, performing integrated change control and closing the project	Mechanisms and functions are in place to support the successful execution and delivery of the project work
Technology Enablement	Includes use of enterprise-wide software and / or applications to facilitate effective management of the end-to-end project management process	Elevate and advance the workforce's performance of all processes outlined in the previous nine Performance Domains

NOTE: Technology Enablement is not reflected as a PMBOK Performance Domain but added due to the importance the proper application of technology will play in utilities achieving their vision for Project Management excellence.

Maturity Scale Rating Criteria

Figure B-1 presents the Maturity Scale applied across each of the 10 Performance Domains, indicating HONI's position relative to the range of "Novice" to "Beyond Standards" and in comparison, to the median and average maturity of the Peer Group Panel.

Figure B-1: Maturity Scale Rating Framework



In the hypothetical image presented in Figure B-1, HONI is shown as “fully integrated” in this generic performance domain, with improvement noted since the previous assessment, and better than the average rating for the Peer Group Panel. The Peer Group Panel ranges between “aware” and “fully integrated.”

Figures B-2 through B-11 convey the actual definitions used in determining the placement of HONI and each Peer Utility in this study.

Figure B-2: Cost Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
No established practices or standards are in use. Cost process documentation is ad hoc and individual project teams follow informal practices.	Project estimates progress with tightening levels of accuracy as project transition from conceptual to definitive estimates. Cost baselines are established, with adjustments occurring for approved increases in scope or as a project nears completion (any contingencies remain under the purview of the Project Manager through completion).	Costs are controlled using a formal change control system, a cost reporting process, and performance measurement analysis. Risk-cost contingencies are tracked, and based on actual results, projects are re-forecasted, and funds are reallocated at the portfolio level.	The characteristics of a competent organization (Level 3) are augmented with the ability to integrate earned value and performance status reporting with cost and schedule systems.	An improvement process is in place to continuously improve Cost Management beyond Level 4. Lessons learned are captured and incorporated into existing processes.

Figure B-3 Scope Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
Poor definition of or discipline around managing scope, and lacking documentation to assist in resolving issues of scope. The focus is on achieving milestones and remaining within budget, but limited focus on whether a project delivers or exceeds the original scope.	Typically, more focused on larger, more complex projects, scope management focuses on specific activities / tasks / expenditures with little consideration to the project or portfolio baseline.	The organization as a matter of process establishes and adheres to baselines, and manages exceptions, relying on a formal scope control system and repeatable processes that report and analyze scope changes and their impact on projects.	The characteristics of a competent organization (Level 3) are augmented with a firm grasp of the basic risk elements that were factored into the baseline, and the ability to make modifications to individual projects based on impacts at the portfolio level.	An improvement process is in place to continuously improve Scope Management beyond Level 4. Lessons learned are captured and incorporated into existing processes.

Figure B-4: Schedule Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
Project schedules exist as separate and distinct items on individual laptops or hardcopy files, lacking any standards for the basic elements that constitute an integrated schedule. Slightly better than a punch list, the ability to identify and analyze schedule performance issues is largely dependent on SMEs.	Individual milestone and activity-level project schedules with inter- and intra-project dependencies are used to track and report progress on activities. Discussions are underway to implement an enterprise-wide solution to standardize methodology and reporting protocols.	Using a common schedule platform, uses a full hierarchy of schedules for each project / program that consider resource constraints when establishing start and completion dates. The schedule is viewed as the primary tool for quantitatively assessing progress. There is an appropriate level of rigor used to identify focus areas for mitigating the impact of any slippage in schedule.	Enterprise-wide resource-loaded schedule (single source of truth) is used to align the organization around the performance of work and strengthen coordination and communication among the various organizations. Strong emphasis on "protecting schedule," assigning defensible and trackable contingency, and applying analytics in reporting progress.	An improvement process is in place to continuously improve Schedule Management beyond Level 4. Lessons learned are captured and incorporated into existing processes.

Figure B-5: Resource Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
Resources are sought out and obtained as tasks begin. Project and resource managers are competing for resources with no provision for properly staging those that are traditionally scarce. No repeatable process applied to planning and staffing projects.	Resource requirements are identified and tracked manually for highly visible / critical projects. Though often ad hoc, the organization is adept at identifying critical resources but lacks visibility to quantify gaps at the portfolio level. Any resource planning occurs at the project level, as the project moves from conceptual to detailed design.	Resource requirements are identified for all labor categories, equipment, and material, using consistent planning processes and methods for determining these requirements, and initial project assignments are reflective of this process. Though resource requirements are not integrated, initial scheduling reflects a full understanding of critical resource constraints across the organization.	The comprehensive view of resource requirements that characterize competent organizations (Level 3) is reflected in resource-loaded activity-based schedules, aggregated at the portfolio level to provide indications of potential resource challenges to support the timely execution of scheduled activities.	An improvement process is in place to continuously improve Resource Management beyond Level 4. Lessons learned are captured and incorporated into existing processes.

Figure B-6: Risk and Contingency Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
Project risks are identified in the form of assumptions and any effort to mitigate the impact of any risk is entirely reactive. Budget contingency is limited to perceived accuracies / inaccuracies in project estimates.	Top risks for major projects are identified and used to build budget contingency. The project manager typically controls this contingency throughout the project with no proactive plans to mitigate the impact of (if not eliminate) these risks.	Project Risks in the form of events and their impact on cost and / or schedule are quantified and entered as contingencies in a risk register. As the risks materialize or are not realized, the forecast is adjusted, and any unused contingency is reassigned at the portfolio level. .	The characteristics of a competent organization (Level 3) are augmented with a more proactive approach to mitigating the impact of risks listed in the risk register. Further individual project risks are aggregated and managed at both the project and portfolio level.	An improvement process is in place to continuously improve Risk and Contingency Management beyond Level 4. Lessons learned are captured and incorporated into existing processes.

Figure B-7: Quality Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
No established project quality practices or standards. Management is considering how they should define and measure "quality."	The project has (1) identified the quality requirements of the deliverables, (2) put in place processes to enable fulfillment of these requirements, and (3) identify steps to check quality during project execution. The focus of Project Management is on strict compliance with these standards, but with limited focus on actual measurement. .	Metrics are established that support quality performance targets for all projects, and specific feedback mechanisms and in-process inspections are established to monitor and drive compliance.	Quality Management transitions from compliance and tracking metrics to ensuring "customer" satisfaction, achieving prevention over inspection, and establishing a culture that thrives on continuous improvement.	An improvement process is in place to continuously improve Quality Management beyond Level 4. Lessons learned are captured and incorporated into existing processes. .

Figure B-8: Contract Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
No formal project contracting process in place; methods are ad hoc. Contracts managed at a final delivery level. Vendors / contractors are not considered part of the project team.	Basic process documented for procurement of goods and services. Contract processes are mostly utilized by large or highly visible projects. Earlier delivery is sought for critical path items.	Process is an organizational standard and used by most projects. Project team and purchasing department integrated in the contracting process. Problem vendors / contractors across projects have been identified. Vendors / contractors have incentives to accelerate delivery on critical items. .	Procurement decisions are made from a total lifecycle cost perspective. Vendors are integrated into the organization's project management systems and methodologies. On-going process improvements with a focus on procurement efficiency and effectiveness metrics.	An improvement process is in place to continuously improve Contract Management beyond Level 4. Lessons learned are captured and incorporated into existing processes. .

Figure B-9: Communications Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
Standard reporting process for project delivery status has not been implemented. Reports are produced on an as requested by management.	Periodic status meetings are occurring though often cancelled and poorly attended, the purpose of which is to coordinate actions during project delivery, and the preparation / issuance of status reports is the primary means for communicating across the organization.	The organization has an effective Communications Plan specifying means, frequency and content of project communication, consistent cadence of communication formats (ranging from phone conversations, to team meetings to routine project reports), and control mechanisms (project performance dashboards) to drive changes, as necessary, to achieve desired outcomes.	Where level 3 has all the basic elements in place with a large internal focus, a fully integrated process augments the project focus with similar protocols at the portfolio level and extends the audience to include (at appropriate levels of detail and disclosures) all stakeholders.	An improvement process is in place to continuously improve Communications Management beyond Level 4. Lessons learned are captured and incorporated into existing processes. .

Figure B-10: Integration Management Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
There is no ability to optimize the trade-offs between cost, schedule, and quality (each is managed separately), or maximize the value of the portfolio in the face of schedule slippages (focus on meeting the forecast without regard for value) or adjust budget forecasts based on realized / unrealized contingencies.	The processes and practices are in place to perform the integration activities listed in the “novice” (Level 1) category, and discussions are underway to provide appropriate system / software support to facilitate implementation.	The systems and applications are in place and actions (though somewhat inconsistent) are underway to optimize the trade-off between cost, schedule, and quality, ensure that replacement projects (in the event of schedule slippages) provide commensurate value, and budget forecasts reflect the realization or removal of risk contingencies.	The systems and applications are in place and actions are in place to consistently optimize the trade-off between cost, schedule, and quality, ensure that replacement projects (in the event of schedule slippages) provide commensurate value, and budget forecasts reflect the realization or removal of risk contingencies.	An improvement process is in place to continuously improve Integration Management beyond Level 4. Lessons learned are captured and incorporated into existing processes.

Figure B-11: Technology Enablement Scoring Criteria

Level 1 Novice	Level 2 Aware	Level 3 Competent	Level 4 Fully Integrated	Level 5 Beyond Standards
Separate and disparate software applications (created by individual users and maintained on PM laptops), addressing specific phases within the PM process, generating constantly evolving PM progress / status reports	Efforts underway to consolidate applications towards an enterprise-wide solution and develop a hierarchy of reports suited for each level of the PM process. Current state, though suboptimal, is adopted across the organization with strong endorsement for a more robust and useful suite of applications.	Uses proven, industry accepted PM software applications, and though not fully integrated, in the aggregate they support pre-defined practices / processes, and generate multi-tiered PM reports that are useful in informing decisions and actions for ongoing projects	Uses proven, industry accepted PM software applications, fully integrated with all pre-defined practices / processes, and generates multi-tiered PM reports that are fully used to inform decisions and actions for ongoing projects	An improvement process is in place to continuously improve Technology Enablement beyond Level 4. Lessons learned are captured and incorporated into existing processes.

APPENDIX C – PEER GROUP TRANSMISSION SYSTEM DEMOGRAPHICS

Table C-1 (below) summarizes basic transmission system demographic information for the Peer Group utilities:

Table C-1: Transmission System Demographics

Company	Transmission Lines (Kilometers) (Approximate)	Number of Transmission Substations
American Transmission Company (ATC)	15,960	560
ATCO Electric	11,000	200
Avista	3,760	51
BC Hydro	18,300	292
DTE Energy	17,700	90
EPCOR (Alberta)	260	30
FirstEnergy	38,600	170
Hydro One Networks Inc.	28,506	328
Louisville Gas and Electric / Kentucky Utilities	7,560	176
National Grid	22,500	500
NB Power	5,000	97
Newfoundland Power	2,060	40
Portland General Electric	2,000	40
Public Service Electric and Gas	2,500	85
Yukon Energy	1,100	17

Transmission Wood Pole Benchmarking Study

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Reference No.: 228649
July 27, 2026

guidehouse.com This deliverable was prepared by Guidehouse Canada Inc. ("Guidehouse") pursuant to a client relationship exclusively with Hydro One Networks Inc. ("HONI"), for the sole purpose of HONI's rate application to the Ontario Energy Board. The information in this deliverable may not be relied upon for any other purpose. The work presented in this deliverable represents Guidehouse's professional judgement based on the information available at the time this report was prepared. Accordingly, Guidehouse disclaims any contractual or other responsibility to others based on their access to or use of the deliverable.

Table of Contents

Disclaimer ii
Executive Summary 1
1. Introduction 2
1.1 Study Objectives 2
1.2 Overview of Approach 2
1.3 Content of Report 3
2. Benchmarking Process 4
2.1 Overview & Methodology 4
2.2 Information Collected 5
2.3 Comparison Group Selection 5
3. Benchmarking Observations 7
3.1 Wood Pole Demographics & Statistics 7
3.2 Wood Pole Replacement 8

List of Tables

Table 1. Information Collected from Hydro One and the Comparison Group 5

List of Figures

Figure 1. Survey Participants 6
Figure 2. Survey Participants Locations 6
Figure 3. Average Age of Wood Pole Structures 7
Figure 4. Percent of Wood Pole Structures Installed per Decade 8
Figure 5. Expected Service Life of Single and Multi-Pole Structures 8
Figure 6. Percent of Poor Condition Wood Pole Structures by Decade 9
Figure 7. Wood Pole Structure Replacements in 2024 and Planned Over 5 Years (2025-2029) 10

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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. (Hydro One) transmission wood pole structures.

This report provides an overview of the study approach and results. It offers insights into the transmission wood pole replacement rates and the wood pole demographics of Hydro One relative to a comparison group of utilities. Primary findings from the study are highlighted below.

- Hydro One primarily replaces transmission wood poles based on condition assessments. While Hydro One's planned replacement rates are broadly consistent with its 50-year expected service life and that is near the median of the comparison group, the planned number of replacements reflects the condition of in-service poles that are in poor condition.
- Approximately 42 percent of Hydro One's total number of transmission structures are single or multi-pole wood, supporting circuits operating at voltages between 115kV and 230kV.
- The average age of Hydro One's wood poles of 36 years is below the 45-year average for the comparison group.
- The age distribution of Hydro One's wood poles has significant variability, with a higher percentage of poles installed before 1960 and after 2000 than most utilities in the comparison group.
- Hydro One's annual pole replacement rate in 2024 and projected over the next 5 years (2025-2029) is between 2.2 and 2.4 percent and is broadly in line with the comparison group.

1. Introduction

1.1 Study Objectives

This study provides a comparative analysis of Hydro One's asset management practices with respect to replacement of transmission wood poles to those of comparable North American electric utilities. In brief, the study was designed to:

- Determine Hydro One's wood pole demographics and replacement rates for transmission wood poles; and
- Benchmark those 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 transmission 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 both transmission and distribution assets, and a smaller group with transmission assets only.

Specifically, the benchmarking study was structured to:

- Include a representative group of utilities to reflect industry characteristics with reasonably expected relevance to and impact on potential findings, including asset demographics; 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. 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 transmission poles; however, the number of respondents providing usable information was insufficient to support a meaningful comparison. As a result, transmission pole unit cost data 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. Given these limitations, no conclusions could be drawn regarding Hydro One's transmission 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 wood pole age and replacement rates.

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 outputs-based assessment and understanding of operating practices of comparable organizations. It is important to present 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 transmission 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. Transmission utility study participants

2.1 Overview & Methodology

The study was designed to compare Hydro One's transmission wood pole structure replacement rates to other transmission 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 and Verification – Gathering and verifying data through a detailed questionnaire directly completed by participating utilities, followed by 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 transmission pole 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 operating practices for wood pole structures. Table 1 summarizes primary information collected from the comparison group for transmission wood pole structures. Transmission system demographics were used to compare assets statistics within the group. Operational practice information was used to compare replacement rates and approaches for replacing wood poles.

Table 1. Information Collected from Hydro One and the Comparison Group

Demographic Information	Practice Information
✓ Number of overhead transmission circuit km and structure km ✓ Number of transmission circuits ✓ Number of transmission structures ✓ Age of wood poles (single and multi-pole structures)	✓ Expected Service Life for wood poles ✓ Poles and structures replaced in 2024 ✓ Plans for wood pole replacements over the next 5 years ✓ Pole replacements by voltage class

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. That 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. 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 is 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.

Figure 1. Survey Participants

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*
26. Tennessee Valley Authority*

Utilities responding to specific survey questionnaire or included publicly available data indicated with an asterisk (*).

Figure 2. Survey Participants Locations

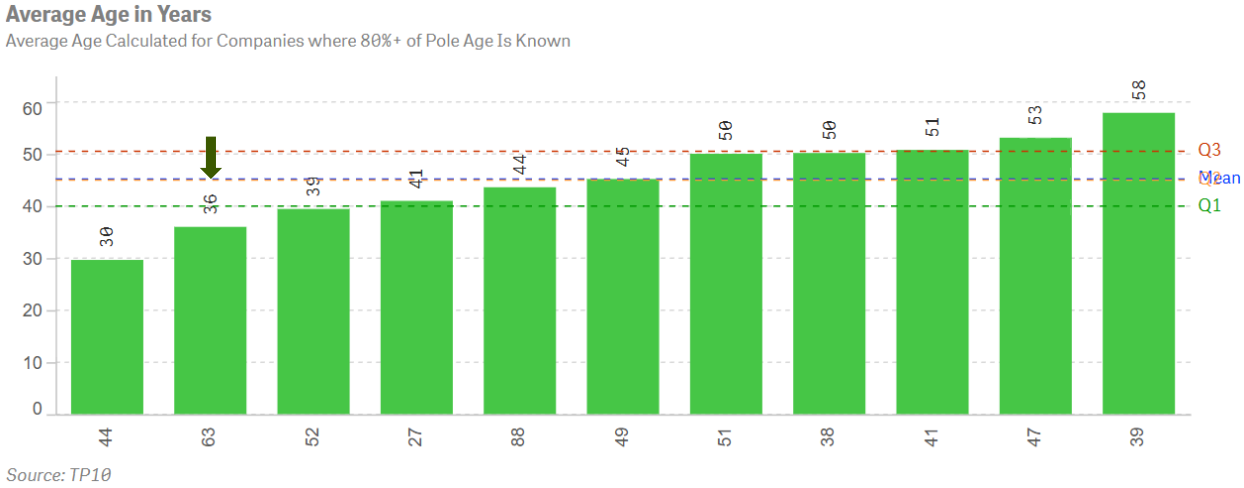
3. Benchmarking Observations

This section summarizes the primary findings of the study via a series of observations of benchmark survey results. Findings are informed by comparisons of wood pole age, expected service life, and replacement rates, among other factors. In the graphs that follow, Hydro One is identified with a green 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 Wood Pole Demographics & Statistics

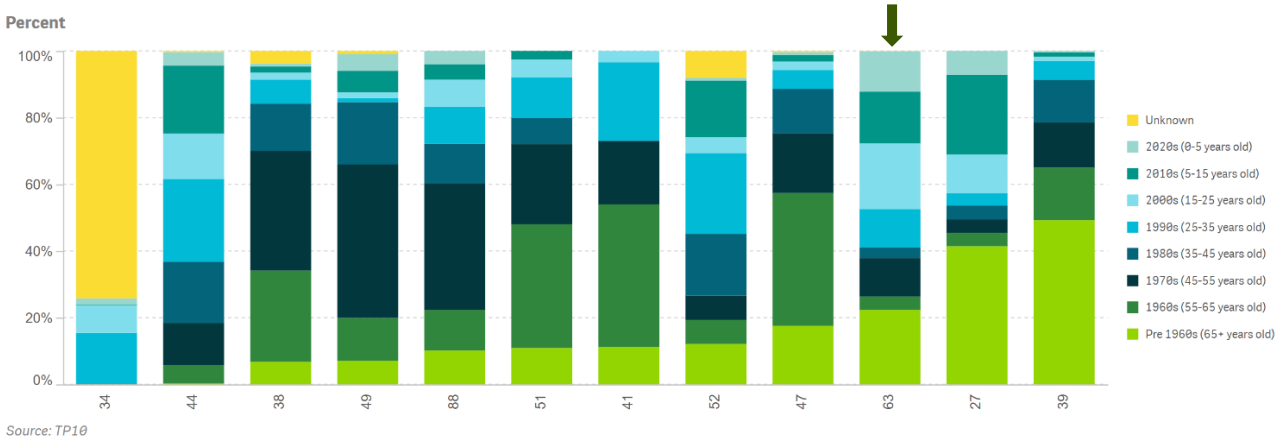
Figure 3 presents the average age of wood pole structures for the comparison utility group. The wood pole structures includes both single and multiple poles, such as H-Frame construction for the latter. The average age of HONI's wood pole structures is 36 years, which is below the average age of 45 years for the group.

Figure 3. Average Age of Wood Pole Structures



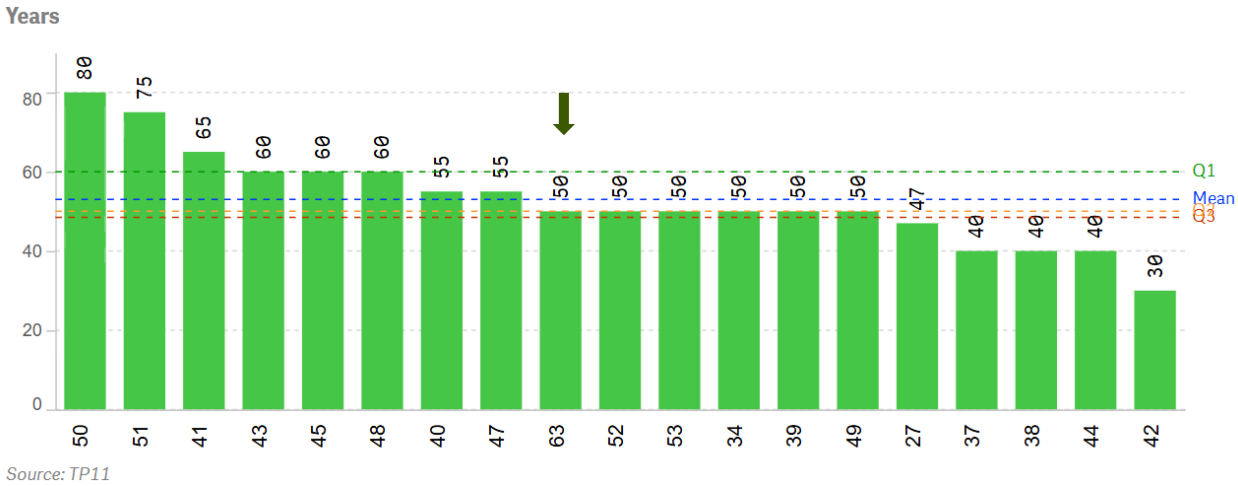
In the evaluation of pole age, the mean of the group population may not be fully indicative of the age and condition of the wood pole fleet. It is also necessary to assess the distribution of the age of the poles as well as the average. Figure 4 presents the distribution of transmission wood poles installed by decade for several utilities. Results indicate that Hydro One has the third largest percentage of wood poles installed pre-1960's as well as a smaller percentage installed in the 1960's and 1970's. Thus, while Hydro One's average wood pole age is 36 years, the lower average age is due to the high percentage of poles that are under 20 years, which offsets the high percentage of poles that are over 50 years old.

Figure 4. Percent of Wood Pole Structures Installed per Decade



Although Hydro One relies on its condition-based field inspections to identify transmission wood poles that are in poor condition and in need of replacement, the age of its wood pole structures versus expected service life provides an indication of potential replacement quantities. Figure 5 indicates the expected service life of Hydro One's wood pole structures at 50 years, which is just below the median of the group and 16 years above the average age of Hydro One's fleet of wood poles

Figure 5. Expected Service Life of Single and Multi-Pole Structures



3.2 Wood Pole Replacement

Hydro One relies on its condition-based field inspections to identify transmission wood poles that are in poor condition. From these inspections, about 19% of transmission wood pole structures were determined to be in poor condition. Figure 6 below shows the breakdown by age of Hydro One's transmission wood pole structures that have been determined by inspection to be in poor condition. Of these poor condition transmission wood poles, a high percentage of those structures (33%) were installed pre-1960. As wood poles get older, they are likely to deteriorate, although the relationship between age and condition may not be linear. Hydro One's data shown in Figure 6 illustrates the prevalence of poor condition poles of Hydro One's wood pole population by decade.

Figure 6. Percent of Poor Condition Wood Pole Structures by Decade

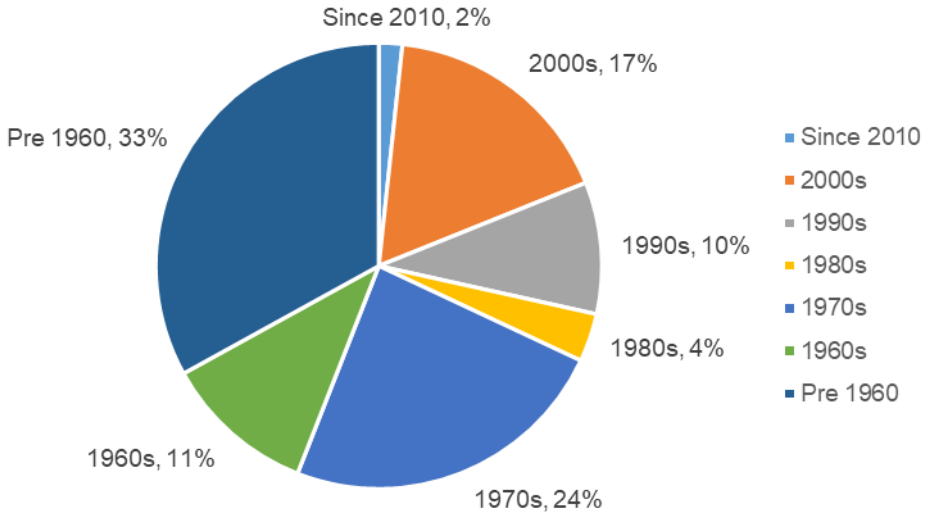
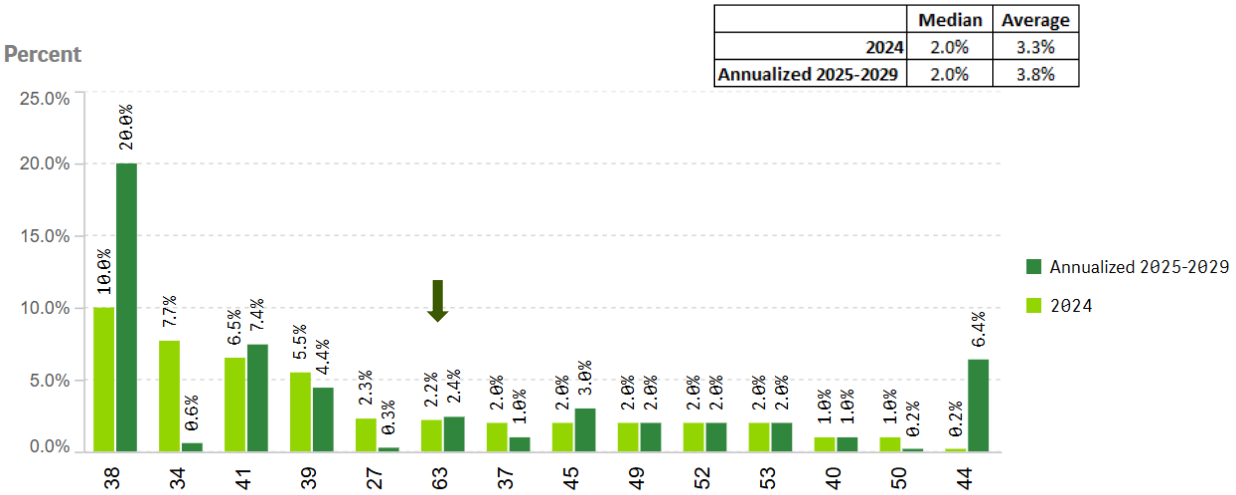


Figure 7 compares the percentage of wood pole structures Hydro One replaced in 2024 (actuals) and projected over the next five years (2025-2029) to those of the utility group. Hydro One's replacement rate (approximately 2.4% annually) is broadly in line with the comparison group, sitting only marginally above the median of 2% (by ~0.2–0.4 percentage points), which is not a material difference.

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.

Hydro One's replacement rates align with the comparison group; however, with 19% of structures already in poor condition and more poles expected to deteriorate over time, overall replacement needs are likely to increase.

Figure 7. Wood Pole Structure Replacements in 2024 and Planned Over 5 Years (2025-2029) [1]



Source: TP12 + TP14

[1] Utility 38 is in the process of replacing all existing transmission wood poles with concrete or steel.

SECTION 2.4 – TSP – TRANSMISSION SYSTEM RELIABILITY

2.4.1 INTRODUCTION

Hydro One's transmission system (including Hydro One Sault Ste. Marie (HOSSM)) is essential to delivering reliable electricity to consumers in Ontario. The transmission system is operated as part of the wider interconnected North American bulk power system according to reliability standards and criteria defined and developed by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). Through the Ontario Reliability Compliance Program, the Independent Electricity System Operator (IESO) monitors, assesses, and enforces compliance in Ontario with NERC reliability standards and NPCC criteria.

Transmission reliability may be viewed from the perspective of NERC and NPCC or transmission customers. NERC determines the reliability of a bulk power system in terms of adequacy and security of supply, such that the system is able to meet end-use customers' needs under most system conditions. Adequacy and security of supply are defined as follows:

- Adequacy is defined as the ability of the system at all times to meet forecast customer demand. That means that adequate generation resources and transmission facilities are available to provide customers with a continuous electric power supply within acceptable voltage and frequency ranges.
- Security is defined as the system's ability to withstand sudden, unexpected disturbances such as short circuits or loss of elements. The loss of these elements could be due to causes such as equipment breakdown, adverse weather conditions, or physical or cyberattacks.

Transmission customers typically view reliability in terms of supply continuity. From the customer perspective, reliability is expressed as the frequency or duration of interruptions over a given period, typically a year, at the customer Delivery Point (DP)[1]. As a customer-

[1] DPs are generally defined as the interfaces between Hydro One's transmission system and its load customers. DPs are either (a) low voltage buses at Hydro One owned step-down transformer stations, or (b) stations owned by transmission load customers, including distributors, such as Hydro One Distribution, and transmission directly connected customers.

focused organization, Hydro One considers the uninterrupted delivery of electricity, from the customer's perspective, to be an important measure of transmission reliability, and it strives to achieve a high level of performance in this area.

Hydro One uses the term reliability in both contexts. The addition of a second transmission line or a transformer station to ensure that adequate supply is available is typically described as work required to improve reliability. Similarly, work to overhaul or upgrade a line connecting to a customer DP would also be described as improving reliability.

Hydro One measures and actively monitors its transmission system reliability from both the delivery and equipment performance perspectives. The delivery performance perspective establishes a measure of how reliably electricity is delivered to transmission customers. The equipment performance perspective enables Hydro One to assess the operational performance of transmission components, ensuring that the transmission equipment is functioning effectively and as designed.

Section 2.4.2 describes the categories of transmission assets and the determinants of reliability from both the bulk system and customer DP perspectives. It explains how transmission system elements contribute to the reliability of individual customer DPs and distinguishes bulk power system reliability from DP reliability. It also discusses the performance of the various asset categories. Section 2.4.3 examines the relationship between capital investment and transmission system reliability. It explains that investments required to maintain bulk transmission system reliability do not necessarily result in immediate improvements in DP reliability because most customers and load in Ontario are served by dual circuits.[2] Section 2.4.3 also presents Hydro One's transmission expenditures across various asset categories. Section 2.4.4 describes Ontario reliability standards and reliability measures, while Attachment 1 discusses First Nations reliability performance.

[2] EB-2019-0082, Decision and Order, April 23, 2020, p. 56. Consistent with OEB direction in EB-2019-0082, Hydro One continued reporting on the relationship between capital investment and transmission system reliability in EB-2021-0110.

2.4.2 TRANSMISSION ASSET CATEGORIES AND RELIABILITY PERFORMANCE

2.4.2.1 CATEGORIES OF TRANSMISSION ASSETS

Hydro One transmission assets are divided into three main categories for rate-allocation purposes. These categories are also helpful in understanding reliability.

- **Network Assets** – These assets comprise the integrated transmission facilities operating at 500 kV, 230 kV, or 115 kV that link major sources of generation to major load centres.
- **Line Connection Assets** – These assets comprise transmission circuits and intermediate stations operating at 230 kV or 115 kV that provide a connection between network stations and transmission load DPs.
- **Transformation Assets** – These assets comprise transformer stations owned by Hydro One that step down the voltage to below 50 kV. These assets include the low-voltage bus from which electricity is supplied from the transmission system to the distribution system or the retail customer and, as previously stated, which is classified as a DP.

Along with the three major asset categories above, there are three other categories:

- **Dual-Function Lines**, which serve both network and line connection functions, are considered with Line Connection Assets for this reliability discussion.
- **Generator Line and Transformation Connections**, which connect generators to the transmission system, are considered part of Network Assets unless they also supply customer DPs, in which case they are considered Line Connection Assets.
- **Common Assets** comprise facilities that support the operation of the overall provincial transmission system and include telecommunications and control equipment, administration buildings and control rooms, minor fixed assets (such as office computers and equipment), and electrical equipment held in reserve. The availability and proper functioning of these assets are necessary for network reliability, and the assets are considered with Network Assets.

The types of transmission assets are illustrated in Figure 1.

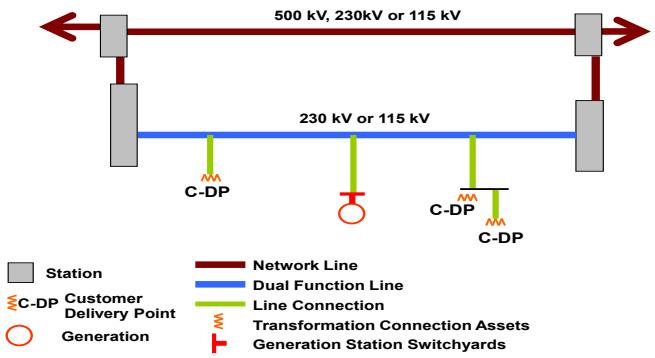


Figure 1: Types of Transmission Assets

2.4.2.2 RELIABILITY PERFORMANCE OF NETWORK TRANSMISSION ASSETS

One requirement of the NERC reliability standards is that the network system must be designed with redundant facilities. The transmission system must be built such that adequate and secure supply is assured over a wide range of conditions so that the loss of an element, such as a line or transformer, will not result in any violation of thermal, voltage, or stability limits. As a result, the system is built with redundancy so that failure of a network element will generally not result in a DP interruption. DP performance is only affected by loss of network transmission system elements if multiple contingencies or overlapping single contingencies occur and more than one element suffers an outage.

Generally, no simple customer-perspective reliability indicators, such as those used to assess DP reliability, exist to monitor the reliability performance of the network transmission system. To ensure network reliability, the IESO studies the reliability impact of connecting new or modifying existing generation, transmission equipment, or customer facilities. In addition, the IESO carries out annual reliability assessments for the current year and the near and long terms to ensure that the transmission system complies with the NERC reliability standards. Further, the IESO and the Hydro Integrated Systems Operations Center continually monitor and assess the system performance to ensure that the system operates within established limits at all times. Hydro One also monitors bulk power system equipment performance to ensure that it operates reliably, that outages are

minimized, and, when outages occur, that the equipment is repaired or replaced as soon as possible.

2.4.2.3 RELIABILITY PERFORMANCE OF LINE CONNECTION ASSETS AND TRANSFORMATION ASSETS

Line Connection Assets and Transformation Assets serve customer DPs. In general, outages on these assets directly affect DP interruption statistics. However, these statistics are shaped to a great extent by the network configuration and historical development of the provincial transmission network, under which loads larger than 75 MW were generally provided with a dual-line supply and smaller loads were connected with a single-line supply. The legacy of this historical configuration exists to this day and influences DP reliability. Since the Transmission System Code operates under a beneficiary-pays model, customers currently supplied by a single line generally will continue to be supplied in the same configuration unless they are willing to pay the cost of a second supply.

Figure 2 shows typical single- and dual-supply DPs. Generally, most DPs are provided with two transformers, but a customer may choose to install only one. Due to the length of time required to repair a failed transformer, dual transformers provide redundancy to serve the customer load, while the failed unit is repaired or replaced. In the case of a DP served by a single supply, both transformers are connected to the same line. In the case of a DP served by a dual supply, each line connects directly to a transformer, and the two transformers are connected in parallel.

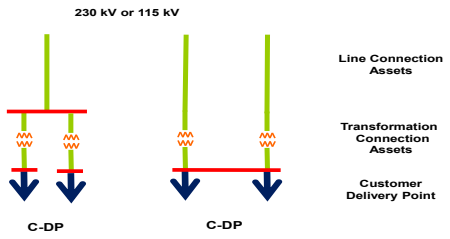


Figure 2: Single and Dual Supply DPs

DPs served by a single supply have lower loads and lower reliability than DPs supplied by double-circuit lines, with line outages being the predominant reason for DP interruptions. These single-circuit-supplied DPs:

- are mostly supplied from 115 kV lines and are generally located in more remote areas;
- have long supply lines that, in many cases, traverse heavily forested or treed areas and therefore are susceptible to outages from broken branches or trees blowing into the lines;
- are generally serviced by wood pole lines, which are more prone to damage from environmental conditions;
- have performance that is determined primarily by the reliability of the line that serves them and is characterized by more frequent interruptions (about three times a year) triggered by line outages; and
- are characterized by longer restoration times (hours instead of minutes) as access is typically difficult and it takes more time to locate and repair the damaged section of the line.

Table 1 presents average DP reliability statistics for Hydro One transmission single-supply delivery points over the 2016-2025 period, while Table 2 presents corresponding statistics for HOSSM transmission single-supply delivery points over the 2019-2025 period.

Table 1 - Hydro One Transmission Single-Supply DPs, 2016–2025*

Voltage Level	No. of DPs****	% Of HONI Load	% of HONI Interruptions	% of HONI Interruptions Duration	DPs with Zero Interruptions	Annual Average DP Interruption Frequency Occurrence	Annual Average DP Interruption Duration Minutes
115kV	220.4	10.6%	75.9%	83.8%	1	2.99	139.7
230kV	25.5	4.2%	2.9%	4.7%	2	0.71	48.5
Total	**255.9**	**14.8%**	**78.9%**	**88.5%**	**3**	**2.67****	**127.1*****

**Totals may not sum due to rounding.*
***Total number of interruptions divided by total number of DPs.*
****Total number of interruption minutes divided by total number of DPs.*
*****Fractional delivery points arise due to the in-year timing of new and retired DPs.*

Table 2 - HOSSM Transmission Single-Supply DPs, 2019[3]–2025*

Voltage Level	No. of DPs	% of HOSSM Load	% of HOSSM Interruptions	% of HOSSM Interruptions Duration	DPs with Zero Interruptions	Annual Average DP Interruption Frequency Occurrence	Annual Average DP Interruption Duration Minutes
44kV	2	4.7%	22.9%	17.5%	0	1.71	98.1
115kV	10	23.4%	63.8%	78.5%	0	0.96	87.9
230kV	1	2.3%	7.6%	0.9%	0	1.14	10.3
Total	**13**	**30.5%**	**94.3%**	**97.0%**	**0**	**1.09****	**83.5*****

**Totals may not sum due to rounding.*
***Total number of interruptions divided by total number of DPs.*
****Total number of interruption minutes divided by total number of DPs.*

DPs served from double-circuit lines generally have higher loads and a high degree of reliability. DP interruptions are infrequent, occurring once every three to four years or less, and are usually short in duration. The major exception is transformer failures that affect both incoming supplies, for which restoration typically takes longer. A multi-circuit-supplied DP suffers an interruption when:

- both supply circuits are affected by a single event such as tower failure due to damage by accident or extreme weather;

[3] Reporting for HOSSM begins in 2019 as this is the first full year of data following the operational integration of HOSSM October 1 2018

- an overlapping outage occurs, where one supply circuit is out for maintenance and an outage occurs on the second supply circuit;
- the DP itself is affected, typically due to weather-related events or animal contact; or
- a tie-breaker outage puts both buses serving the DP out of service.

Tables 3 and 4 present the reliability performance of dual-supply DPs for Hydro One and HOSSM, respectively. Dual-supply DPs exhibit a high degree of reliability.

Table 3 - Hydro One Transmission Dual-Supply DPs, 2016–2025

Voltage Level	Avg Num of DPs	% of HONI Load	% of HONI Interruptions	% of HONI Interruption Duration	DPs with Zero Interruptions	Annual Average DP Interruption Frequency Occurrence	Annual Average DP Interruption Duration Minutes
115kV	296.4	24.0%	11.3%	5.9%	36	0.33	7.3
230kV	350.3	61.1%	9.8%	5.6%	44	0.24	5.9
Total	**646.6**	**85.2%**	**21.1%**	**11.5%**	**80**	**0.28****	**6.5*****

**Totals may not sum due to rounding.*
***Total number of outages divided by total number of DPs.*
****Total number of outage minutes divided by total number of DPs.*

Table 4 - HOSSM Transmission Dual-Supply DPs, 2019[4]–2025

Voltage Level	Avg Num of DPs	% of HOSSM Load	% of HOSSM Interruptions	% of HOSSM Interruption Duration	DPs with Zero Interruptions	Annual Average DP Interruption Frequency Occurrence	Annual Average DP Interruption Duration Minutes
115kV	5	69.5%	5.7%	3.0%	0	0.17	6.8
Total	**5**	**69.5%**	**5.7%**	**3.0%**	**0**	**0.17****	**6.8*****

DP reliability statistics are a lagging indicator of customer interruptions as they capture interruptions only after they occur. As a result, any decline in reliability performance is observed only after a number of customers have already been affected and service to communities may have already been compromised. A comparison of Tables 1 and 2 shows that the majority of interruptions occur on 115 kV single-supply DPs, with roughly 10.6% of the load experiencing 75.9% of the interruptions. Interruptions on single-supply

[4] Reporting for HOSSM begins in 2019 as this is the first full year of data following the operational integration of HOSSM October 1 2018

DPs are primarily due to outages of the supply circuit, which are caused primarily by the higher exposure of long supply lines.

For dual-supply DPs, line outages have less impact on supply reliability. The probability that both circuits supplying a DP will fail simultaneously is very low. The frequency of interruptions for these DPs is low, and DP interruptions are typically due to equipment at the DP itself or a severe weather event. A failure of one of the two transformers supplying the DP does not impact service to customers because they continue to receive uninterrupted supply from the remaining transformer.

Such failures are nonetheless a major concern for Hydro One, local distribution companies (LDCs), and customers supplied from the DP. This concern arises because replacing a failed transformer takes a considerable amount of time. At any point during the replacement of the failed transformer, an outage affecting the second line, whether on the line itself or on the second transformer, would result in a serious and lengthy DP interruption.

Another matter of concern when one of two transformers fails is the loading on the transformer remaining in operation. Hydro One's design criteria for Dual Element Spot Network (DESN) stations require that one transformer be able to temporarily carry all the load if the companion transformer goes out of service. When one transformer is out of service, the in-service transformer can experience loading of up to 130%–160% of its rating, depending on seasonal conditions. If both transformers are in poor condition, there is an increased likelihood that the transformer remaining in service may also fail under these adverse loading conditions, resulting in a lengthy DP interruption.

Given the critical role of electricity in the functioning of Ontario's homes, businesses, and institutions, Hydro One's priority is to ensure that transmission facilities remain in service. The station renewal program focuses on replacing transformers based on asset condition. Transformers in poor condition are replaced in a controlled manner so that any potential safety risks and other customer impacts from DP interruptions are minimized.

2.4.3 TRANSMISSION ASSET CATEGORY EXPENDITURES

Hydro One transmission capital expenditures are intended to ensure that the transmission system continues to provide reliable supply. Tables 5 and 6 present planned System Renewal capital expenditures by allocation, including the network, line connection, transformation, and common pools, for Hydro One and HOSSM, respectively.

Table 5 - Hydro One 2028–2032 Net System Renewal Capital Expenditures ($M)

Pool	OEB Investment Category	2028	2029	2030	2031	2032	Total
Network	System Renewal	379.2	394.7	535.7	712.0	661.7	2,683.3
Line Connection	System Renewal	234.9	304.4	412.1	419.8	314.7	1,685.9
Transformation	System Renewal	217.9	226.3	353.6	608.4	687.8	2,094.1
Common	System Renewal	123.2	147.0	133.5	124.3	102.3	630.2
Grand Total		**955.2**	**1,072.4**	**1,435.0**	**1,864.4**	**1,766.6**	**7,093.5**

Table 6 - HOSSM 2027–2032 Net System Renewal Capital Expenditures ($M)

Pool	OEB Investment Category	2027	2028	2029	2030	2031	2032	Total
Network	System Renewal	8.3	10.1	2.7	2.7	2.8	2.8	29.4
Line Connection	System Renewal	2.1	2.5	2.6	2.6	2.7	2.7	15.2
Transformation	System Renewal	7.6	21.4	14.3	15.2	15.6	6.6	80.7
Common	System Renewal	1.2	1.2	1.2	1.2	1.3	1.3	7.4
Grand Total		**19.2**	**35.2**	**20.7**	**21.8**	**22.3**	**13.4**	**132.6**

The network pool represents expenditures on network assets, which are generally NERC and NPCC Bulk Electric System (BES) or bulk power system (BPS) facilities. For Hydro One, the network pool is the largest expenditure allocation within System Renewal and addresses refurbishment work at major stations such as Claireville TS, Manby TS, Merivale TS, and Fort Frances TS, as well as refurbishment of 230 kV network lines. For HOSSM, the network pool represents the second-largest expenditure allocation, reflecting the nature of the HOSSM transmission system. Network pool expenditures are required to ensure that the transmission network meets all relevant IESO, NPCC, and NERC criteria. However, because of the redundancy of this infrastructure, these expenditures are not typically quantifiable as immediate improvements to DP reliability statistics. Failure

to undertake this work could increase the risk of widespread and prolonged outages and impair Hydro One's and HOSSM's abilities to meet their mandatory reliability compliance obligations. Further, these key network points support overall system adequacy, and unplanned failures can materially affect generation and load across the province and may require the IESO to implement special operating measures to minimize system risks.

The transformation pool includes refurbishment work on transformers and low-voltage (LV) yards at DESN stations. For Hydro One, the transformation pool is the second largest expenditure allocation within the System Renewal category. Due to the nature of the HOSSM transmission system, the transformation pool represents the largest expenditure allocation for HOSSM. As noted above, while dual-supply DP reliability is currently good, poor-condition and obsolete transformers and associated low-voltage connection equipment pose a significant risk to both DP reliability performance and public safety. These expenditures are intended to minimize these risks cost-effectively through ongoing investment in transformation pool assets. This category of expenditures does not typically result in immediate and quantifiable improvements to DP reliability statistics due to the predominance of dual-supply configurations.

For both Hydro One and HOSSM, the third-largest expenditure allocation category is line connection refurbishment. This category includes work to improve the reliability of customers on a single supply. These single-supply lines serve a vital function in providing service to DPs with smaller loads and connecting generation. These lines serve a variety of customers, including local distribution companies, First Nation communities and businesses, pipeline compressor stations, large-load facilities such as mines and paper mills, and generators. This category of expenditures typically results in immediate improvements to DP reliability statistics.

The final expenditure allocation category is Common Assets. These expenditures include investments in telecommunications and other assets required for the reliable operation of the transmission system, as described earlier.

2.4.4 RELIABILITY MEASURES AND STANDARDS

Hydro One measures and monitors its transmission system reliability from two principal perspectives: delivery performance and equipment performance. The delivery performance perspective measures the reliability of electricity supply to transmission customers, such as the Hydro One distribution system, LDCs, and transmission direct-connect customers. The equipment performance perspective assesses whether transmission equipment is operating effectively and as designed. As a customer-focused organization, Hydro One considers the delivery of electricity to be a core measure of transmission reliability, and it strives to achieve a high level of performance in this area.

Transmission reliability is determined using measures developed collaboratively with other transmission utilities across Canada through Electricity Canada's (EC) Transmission Reliability Committee (TRC). These measures have been widely adopted since they are well-defined and understood by the participating member utilities. The metrics are sufficiently precise and consistent over time to be used for historical performance trending and multi-jurisdictional transmission performance comparisons.

Hydro One is also subject to Ontario reliability standards, which are based on NERC standards and memoranda of understanding between the OEB and NERC and among the IESO, NERC, and NPCC. The IESO is responsible for ensuring compliance with the standards and criteria through the market rules. These rules are captured in the IESO's Ontario Resource and Transmission Assessment Criteria.[5]

2.4.4.1 DELIVERY POINT RELIABILITY MEASURES

Hydro One measures customer reliability by monitoring the frequency and duration of forced interruptions at DPs. There are two types of DPs. One type is the low-voltage bus in a Hydro One-owned transformer station, and the other is a demarcation point where a customer-owned station connects to the transmission lines. Since all DPs are ultimately supplied by the bulk power system, a reliable bulk power system is essential to the

[5] IESO - Ontario Resource and Transmission Assessment Criteria.
https://www.ieso.ca/en/Sector-Participants/Market-Operations/Market-Rules-And-Manuals-Library

reliability and security of supply experienced at customer DPs. Table 7 summarizes the DP reliability measures that are monitored.

Table 7 - DP Reliability Measures

Perspective	Measure	Description
Reliability of Delivery of Electricity to Customers	Frequency of DP Interruptions	Average number of interruptions experienced at DPs due to forced interruptions.
	Duration of DP Interruptions	Average duration, in minutes, of interruptions experienced at DPs due to forced interruptions.
	Delivery Point Unreliability Index – a measure of unsupplied energy[6]	Energy not supplied to customers due to forced interruptions, normalized by system peak load and presented in system minutes.

Hydro One's rationale for employing these measures is as follows:

- These metrics are commonly used transmission reliability measures in the industry, especially in Canada. As a group, the measures address transmission service reliability, which is important to customers and stakeholders.
- The benchmarking of these measures is meaningful since the data collection and reporting practices among all EC member utilities are consistent and have been developed and refined over time.
- These measures have been in place for several decades, which facilitates internal performance trending, target setting, and external benchmarking.
- The limited number of measures keeps tracking and reporting requirements at a manageable and cost-effective level while still covering a broad spectrum of transmission reliability performance.

A summary of DP performance according to the Hydro One Customer DP Performance (CDPP) Standards is discussed below in the DP performance outliers section. The standards are included in Attachment 2 and are summarized from a Hydro One document previously filed with the OEB, Customer DP Performance (CDPP) Standards, EB-2002-

[6] This measure appears on the Hydro One Transmission Scorecard as "Unsupplied Energy (System Minutes)." See TSP Section 2.5.

0424. Additionally, Attachment 3 provides definitions and detailed descriptions of the reliability measures used in this evidence.

On November 27, 2025, the OEB approved changes to the CDPP Standards in a letter to transmitters, EB-2021-0307. On March 1, 2026, as required by the OEB, Hydro One filed revised CDPP Standards to reflect these changes and is awaiting OEB approval. Drafts of the revised CDPP Standards are included in Attachment 4 for Hydro One and Attachment 5 for HOSSM.

2.4.4.2 EQUIPMENT RELIABILITY MEASURE

Hydro One measures and actively monitors its transmission system equipment performance using transmission system unavailability, as described in Table 8. This perspective enables Hydro One to assess the operational performance of transmission components, ensuring that the equipment functions effectively and as designed.

Table 8 - Equipment Reliability Measures

Perspective	Measure	Description
Performance of Transmission System	Transmission System Unavailability	Captures the total duration that transmission equipment is out of service due to unplanned outages, measured as a percentage.

Electricity Canada (EC) collects reliability and outage statistics for its members. It has coordinated the development of electricity reliability information, including information on transmission reliability. The measures discussed in this section follow the definitions developed by EC and consistently applied by its members.

In any year, extraordinary events may occur which can significantly impact the performance of an individual utility, and if sufficiently large, the overall EC composite index. Inclusion of such events could significantly affect both the results for the utility that experienced the event and the annual average for all participants. For this reason, beginning in 2017, EC excluded extraordinary events from its comparisons, as discussed in the next section.

2.4.4.3 EXCLUSION OF EXTRAORDINARY EVENTS

Outages resulting from extraordinary events, such as the 1998 Eastern Ice Storm, the 2003 Northeast Blackout, and the 2013 GTA Flood, that have an impact on the transmission system exceeding one million MW-minutes and, in Hydro One's assessment, strongly skew the historical trend of the measure, have been excluded, consistent with the EC methodology.

Hydro One also removes major events that exceed 10,000 MW-minutes in unsupplied energy from its reliability metrics.[7] This exclusion threshold has been determined using a statistical method, log-standard deviation (β), to identify major unsupplied-energy events. This threshold corresponds to an EC Degree of Severity Level 2 disturbance event. With this methodology, interruptions caused by equipment failure and human error are not excluded because Hydro One considers them controllable. Hydro One has applied this exclusion threshold to performance tracking and target setting since 2019 for DP-related performance metrics.

2.4.4.4 RELIABILITY METRIC COMPARISONS

2.4.4.4.1 DP METRIC COMPARISONS

Using data collected by EC, Hydro One compares the reliability performance of its transmission system with the average performance of Canadian transmission utilities. The comparison of DP reliability performance is done at the system level, reflecting the system average of all DPs.

Hydro One's comparative reliability performance at the system level is illustrated in the following figures, which demonstrate the impact of forced interruptions:

- Figure 3 – Frequency of Momentary Interruptions;
- Figure 4 – Frequency of Sustained Interruptions;
- Figure 5 – Overall Frequency of Interruptions;
- Figure 6 – Average Duration of Sustained Interruptions; and

[7] If an event meets the threshold for an extraordinary event, it is also not considered as a major event to avoid double counting.

- Figure 7 – DP Unreliability Index.

As the figures demonstrate, Hydro One's performance is better than the EC composite for all of these metrics.

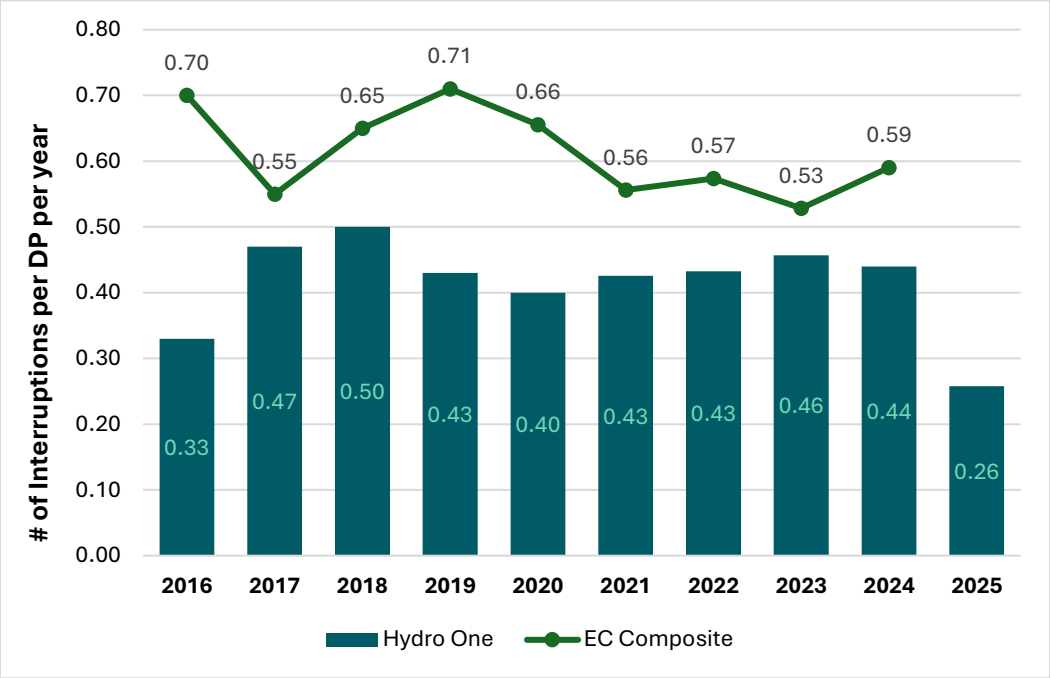


Figure 3: Frequency of Momentary Interruptions, Hydro One vs. EC Composite[8]

[8] EC Composite values include Hydro One performance for all measures.

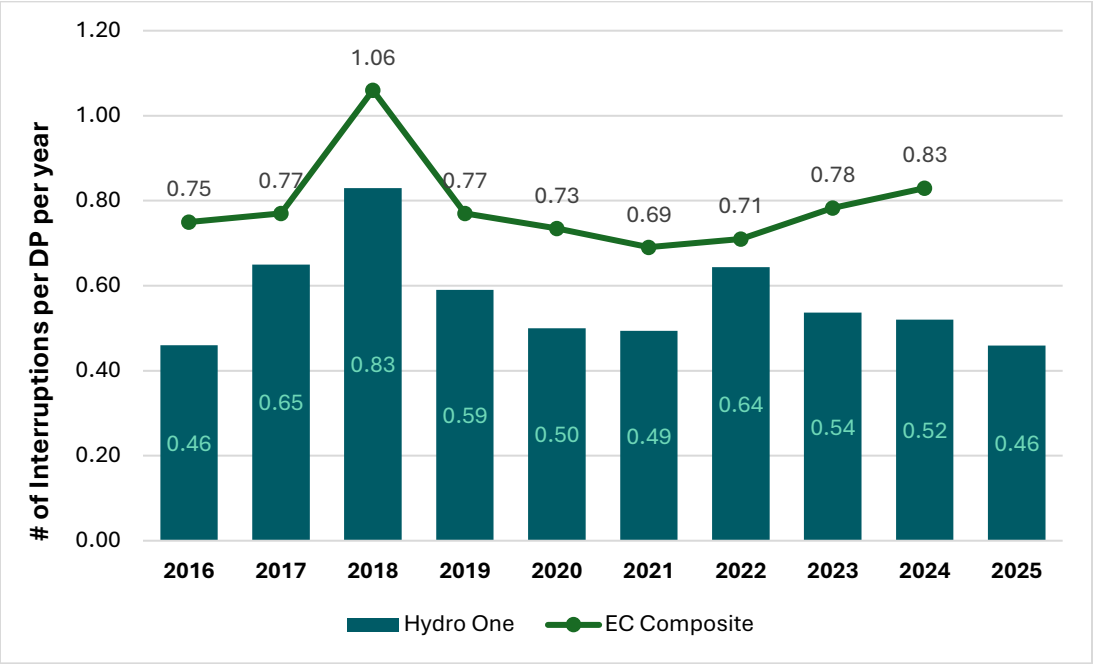


Figure 4: Frequency of Sustained Interruptions, Hydro One vs. EC Composite

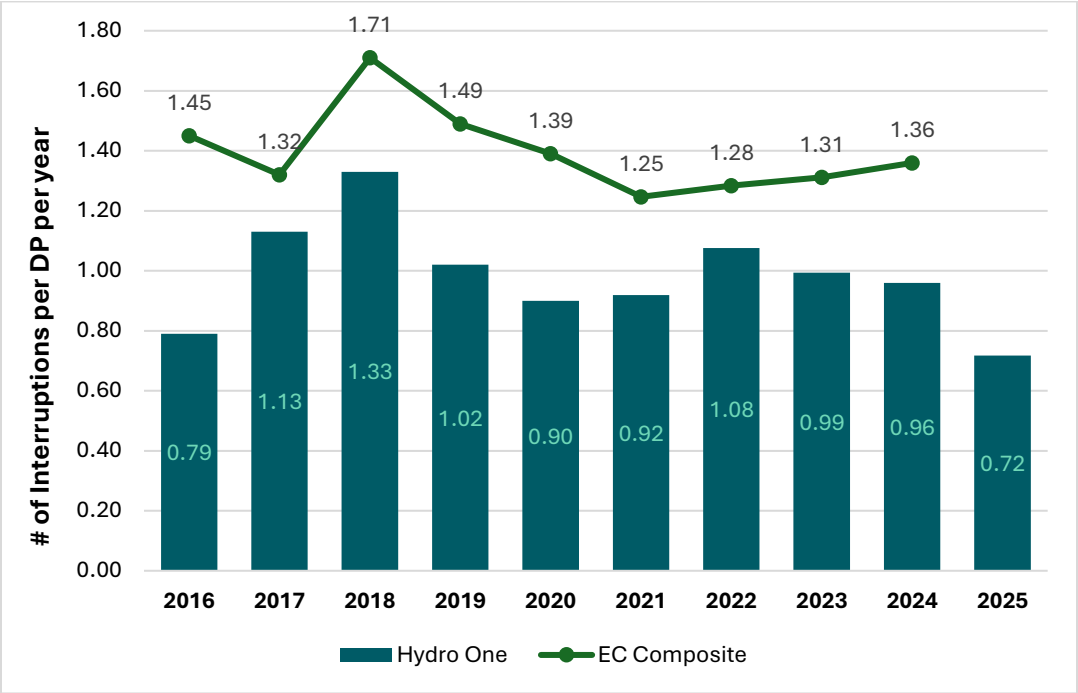


Figure 5: Overall Frequency of Interruptions, Hydro One vs. EC Composite

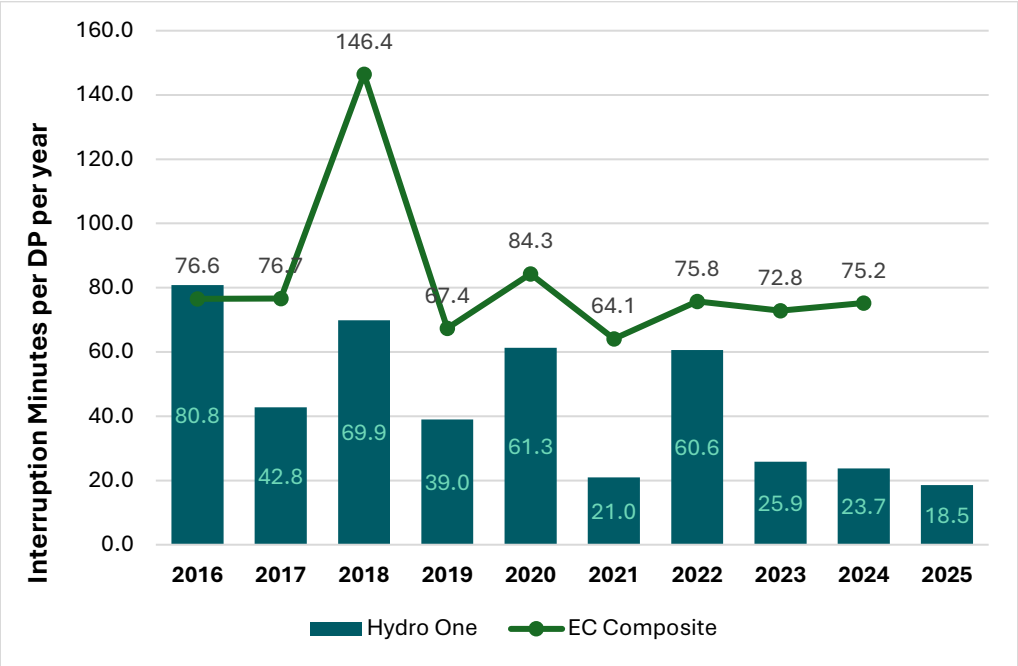


Figure 6: Average Duration of Sustained Interruptions, Hydro One vs. EC Composite

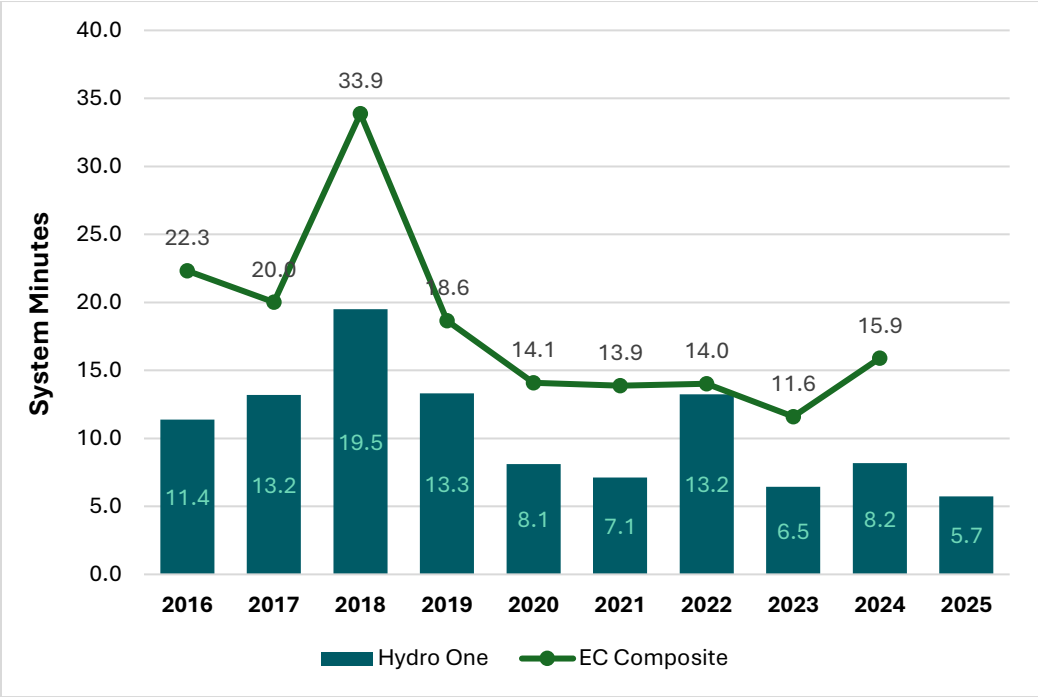


Figure 7: DP Unreliability Index, Hydro One vs. EC Composite

HOSSM reliability performance at the system level is illustrated in the following figures, which demonstrate the impact of forced interruptions:

- Figure 8 – Frequency of Momentary Interruptions;
- Figure 9 – Frequency of Sustained Interruptions;
- Figure 10 – Overall Frequency of Interruptions;
- Figure 11 – Average Duration of Sustained Interruptions; and
- Figure 12 – DP Unreliability Index.

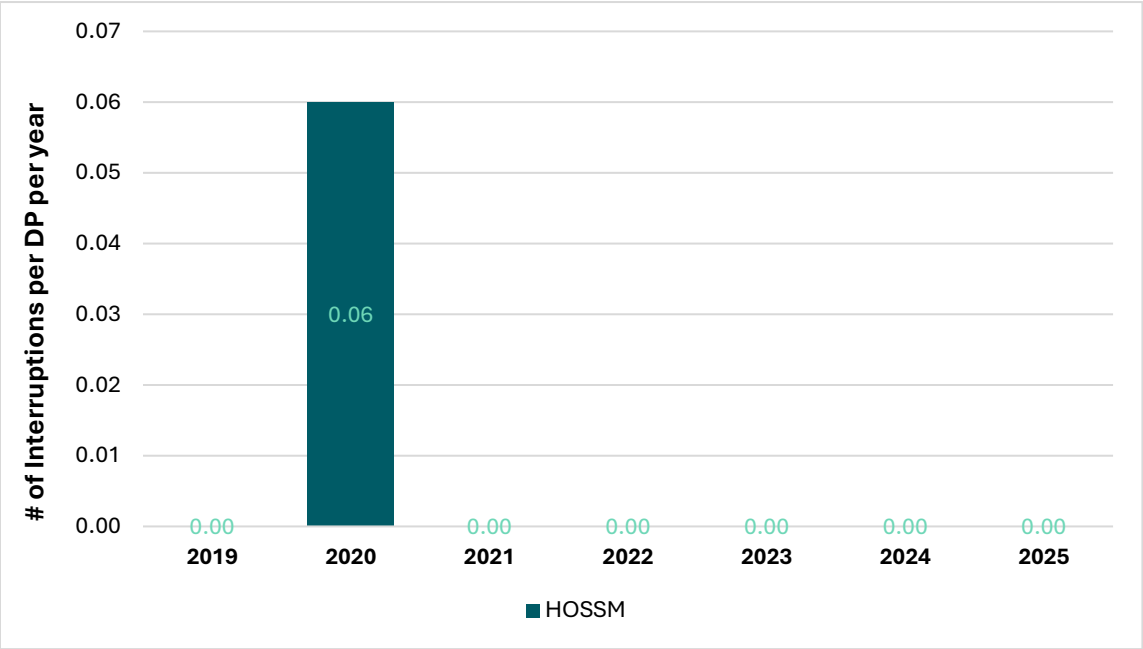


Figure 8: Frequency of Momentary Interruptions, HOSSM

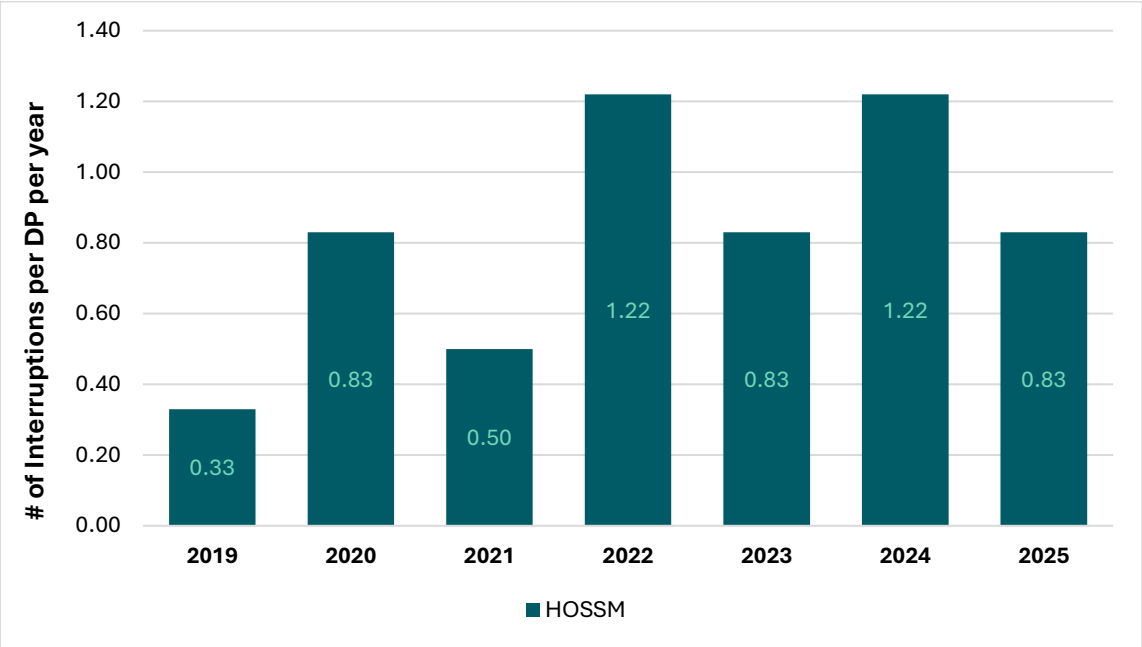


Figure 9: Frequency of Sustained Interruptions, HOSSM

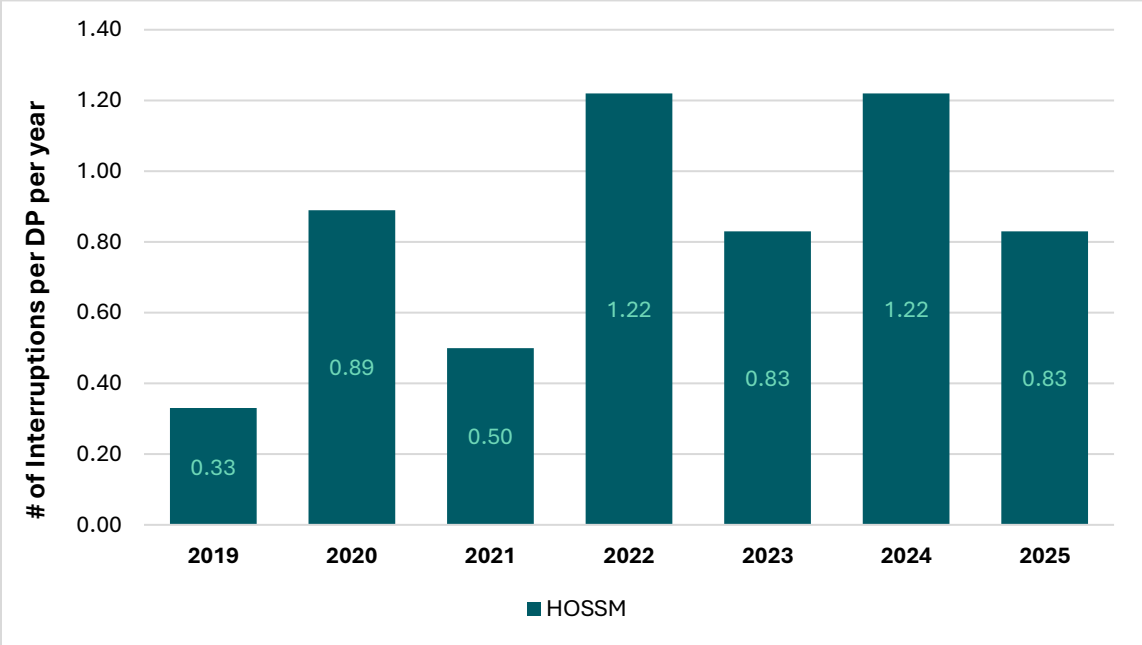


Figure 10: Overall Frequency of Interruptions, HOSSM

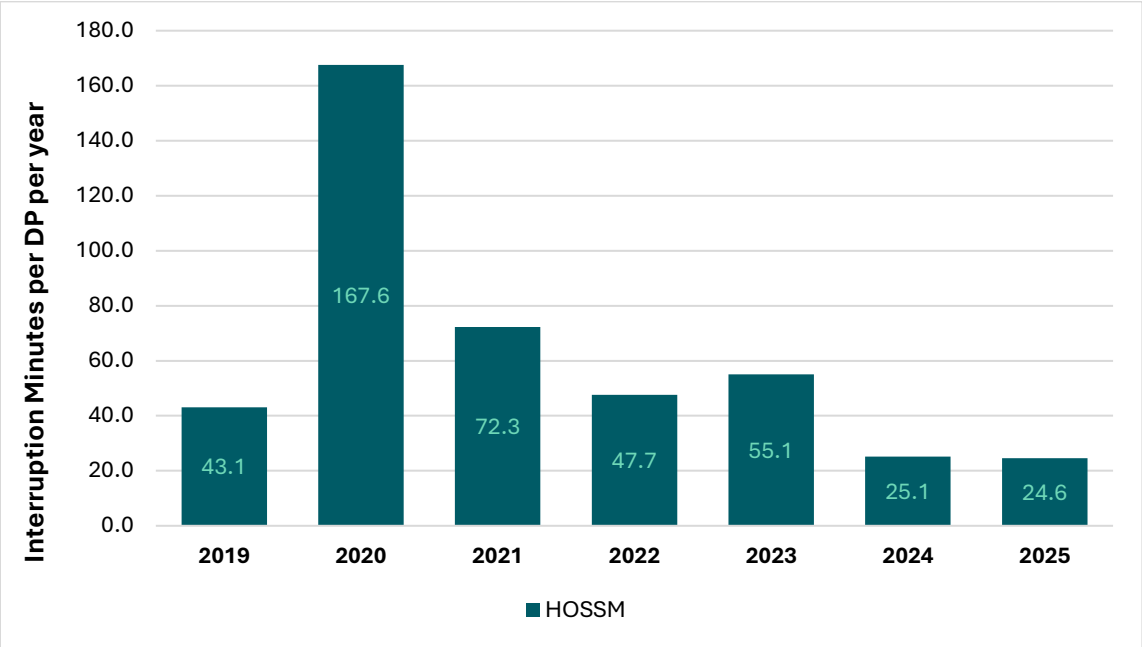


Figure 11: Average Duration of Sustained Interruptions, HOSSM

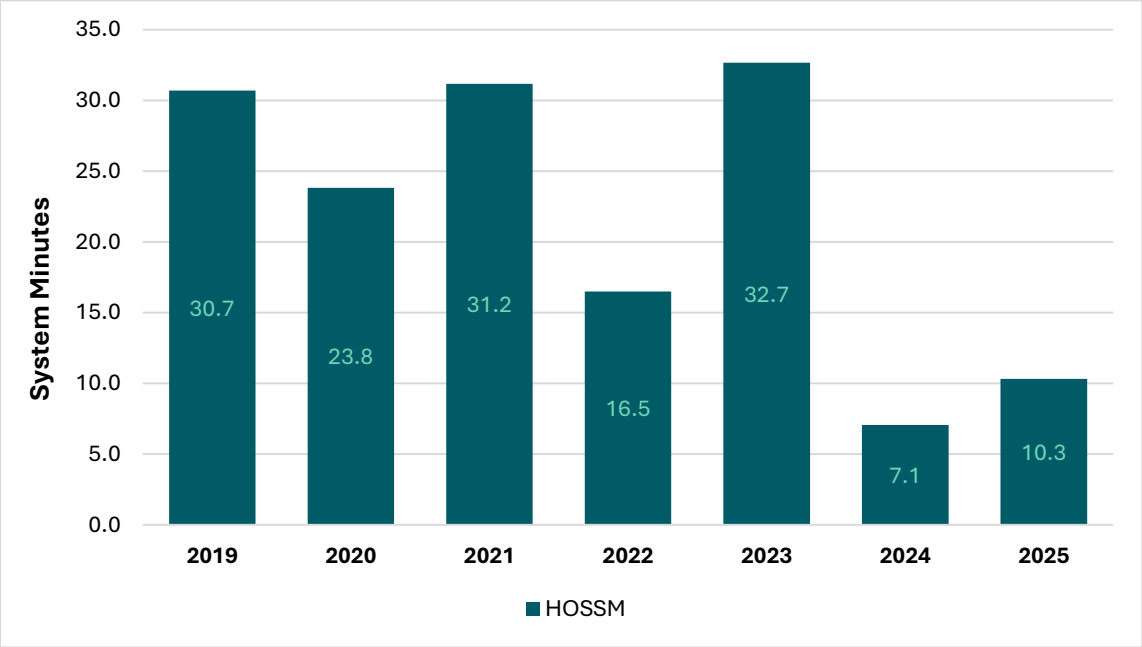


Figure 12: DP Unreliability Index, HOSSM

2.4.4.4.2 SYSTEM UNAVAILABILITY METRIC COMPARISONS

In this evidence, transmission system forced unavailability is divided into the unavailability of transmission lines and the unavailability of transmission station equipment, as shown in:

- Figure 13 – Unavailability of Transmission Lines; and
- Figure 14 – Unavailability of Major Transmission Station Equipment.

This division is based on the different characteristics of the equipment.

Transmission station equipment includes power transformers, circuit breakers, and other equipment. The unavailability measure represents the extent to which major transmission equipment is unavailable for use within the system due to forced outages. A detailed description of this measure is provided in Attachment 3. Figures 13 and 14 illustrate the historical annual performance of Hydro One's lines and station equipment compared with the five-year moving average of the EC composite, which reflects the performance of EC member utilities.

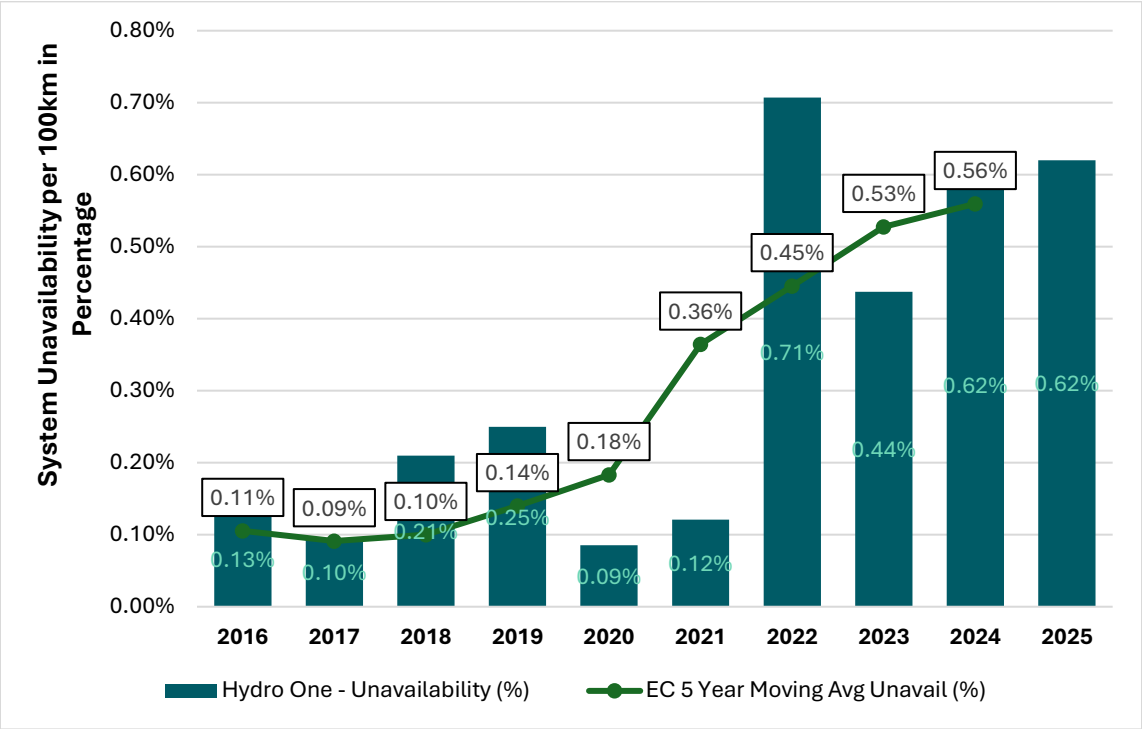


Figure 13: Unavailability of Transmission Lines[9]

As shown in Figure 13, the unavailability of transmission lines measure deteriorated in 2022, reflecting an increase in line terminals remaining out of service. Issues with equipment at line terminals contributed to line unavailability. The lines were still supplied from the other terminal, but the system was being operated in a less redundant state while disconnect switches and sulphur hexafluoride (SF_6) gas-insulated bus ducts were being repaired at line terminals.

[9] Beginning in 2020 Electricity Canada data collection for transmission equipment outages changed from 3 phase equivalent basis to reporting on all pieces of equipment in an operating designation to gather more details on installed equipment.

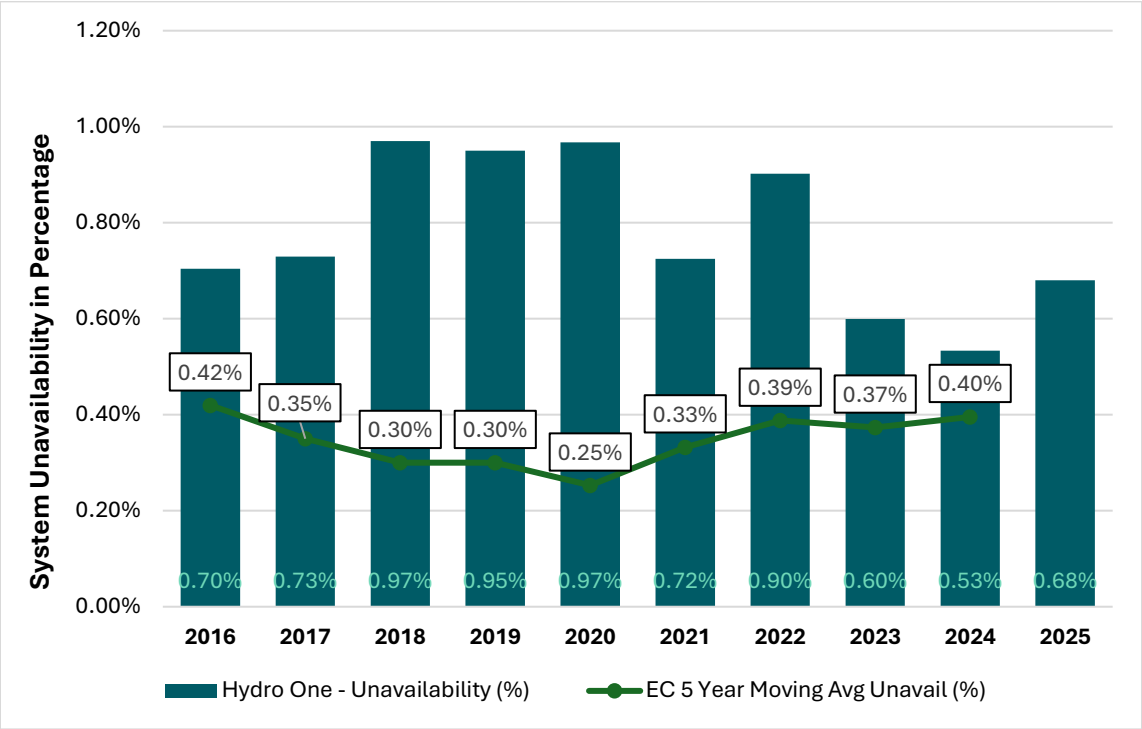


Figure 14: Unavailability of Major Transmission Station Equipment[10]

Hydro One's transmission station equipment has recently shown improved system-unavailability performance compared with previous years. Major contributors to the unavailability metric are as follows:

1. Transformers that were nearing retirement experienced forced outages. Since the loss of these transformers did not impact customers or reliability (because the load they had served had already moved to other equipment), they were not repaired. However, until they were decommissioned, they still counted toward Hydro One's equipment unavailability measures.
2. Transformer replacement projects can take months or even years to complete. When a transformer forced outage occurs just before a replacement project—that is, before a planned outage—the total duration of the project is treated as forced rather than planned unavailability and contributes to equipment unavailability even

[10] Beginning in 2020 Electricity Canada data collection for transmission equipment outages changed from 3 phase equivalent basis to reporting on all pieces of equipment in an operating designation to gather more details on installed equipment.

in circumstances where Hydro One employed an alternative supply arrangement to restore system operation and supply customers.

3. When capacitor banks and breakers are forced out of service, they contribute to equipment unavailability even if their unavailability does not immediately impact the system. In such circumstances, Hydro One may defer repairs for significant periods of time due to resource constraints or the lack of available outage windows, with the deferral contributing to high system unavailability.
4. Defects on switches contribute to unavailability and may not immediately impact the system. Depending on the nature of the defect, the switch may be left in either the open or closed position until the defect can be repaired. Hydro One may defer repairs for significant periods of time due to resource constraints or the lack of available outage windows, with the deferral contributing to high system unavailability.

Equipment performance is a leading indicator of future system reliability. By the time system reliability has measurably degraded, equipment performance will have deteriorated, and a significant increase in asset-level investment will be required to return to historical reliability levels. Renewal investments preserve the performance of critical asset groups by evaluating assets at both the individual-asset and station-or-line levels. This approach prioritizes investment needs, identifies the most effective reliability alternative, and helps preserve overall system reliability.

In this evidence, HOSSM transmission system forced unavailability is divided into the unavailability of transmission lines and the unavailability of transmission station equipment, as shown in:

- Figure 15 – Unavailability of Transmission Lines; and
- Figure 16 – Unavailability of Major Transmission Station Equipment.

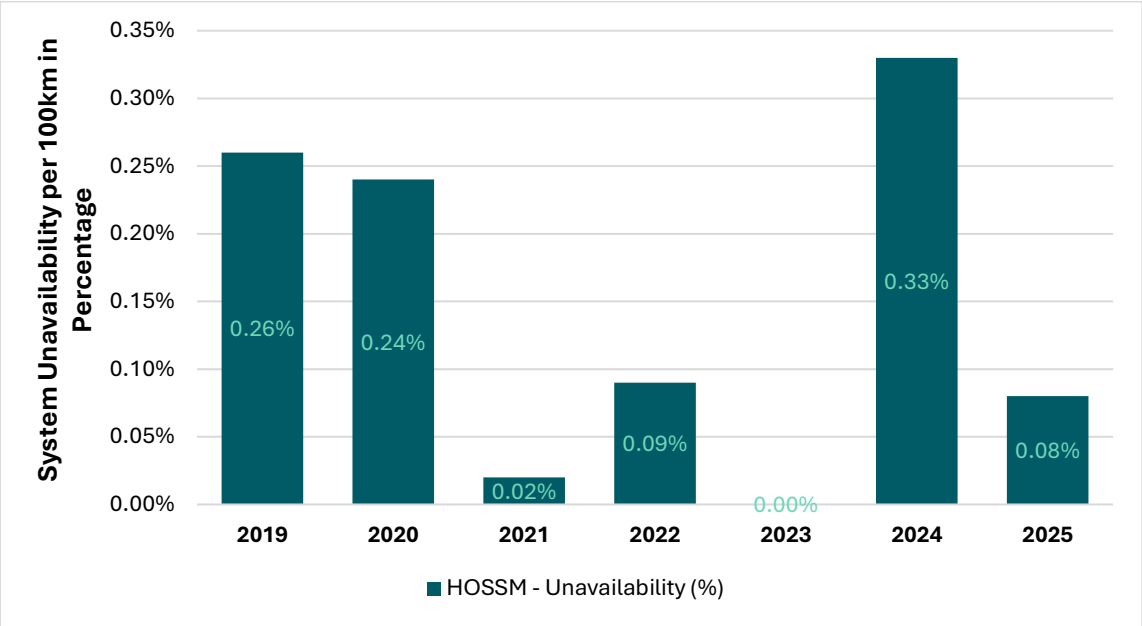


Figure 15: Unavailability of Transmission Lines

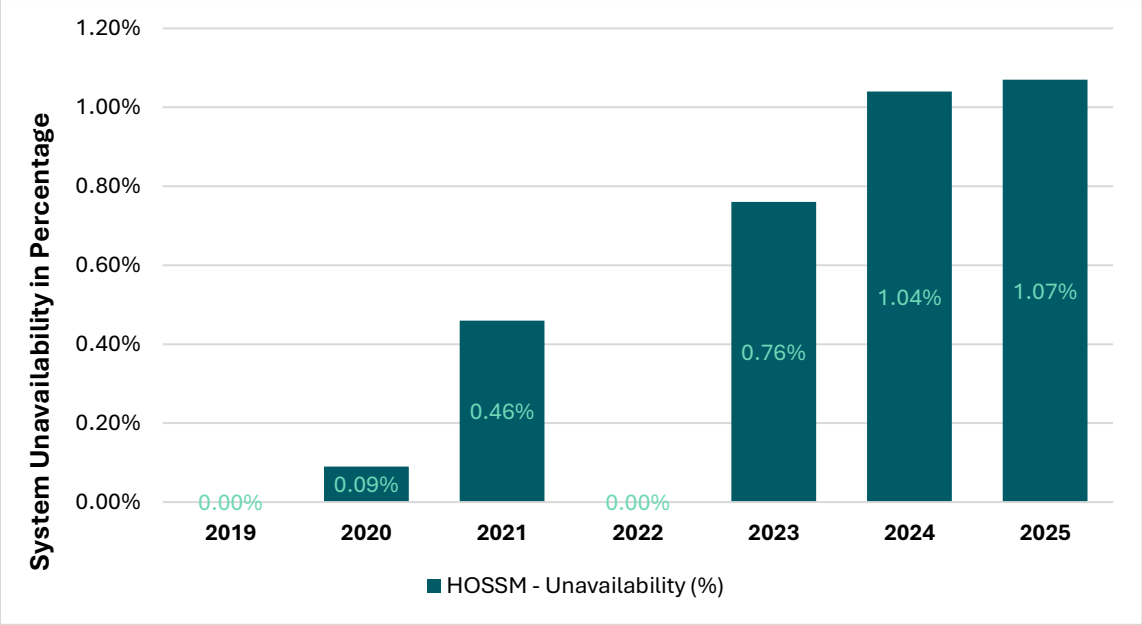


Figure 16: Unavailability of Major Transmission Station Equipment

2.4.5 DELIVERY POINT PERFORMANCE OUTLIERS

DP performance is evaluated according to Hydro One's Customer DP Performance (CDPP) Standards, which were approved by the OEB in EB-2002-0424. The performance standard triggers an assessment and, where required, follow-up with affected customers to:

- determine the root cause of unsatisfactory performance;
- perform technical and financial evaluations; and
- decide on remedial action to address the root cause.

Figures 17 and 18 summarize the transmission group and individual outliers identified under the CDPP Standards for Hydro One and HOSSM, respectively.

Based on the CDPP Standards, a DP is identified as a group outlier in a given year when its most recent three-year average interruption frequency or duration exceeds the minimum performance threshold for customers in its load class, as defined by the group outlier standard[11]. A DP is identified as an individual outlier if its annual interruption frequency or duration exceeds the individual outlier baseline for two consecutive years. As shown in Figures 17 and 18, the individual outlier baselines are based on the DP's historical performance. The group and individual CDPP Standards criteria are not mutually exclusive. A DP can be both a group outlier and an individual outlier in the same year.

On November 27, 2025, the OEB approved changes to the CDPP Standards, specifically the group outlier standard (EB-2021-0307, Letter to Transmitters). On March 1, 2026, as required by the OEB, Hydro One filed revised CDPP Standards to reflect these changes and is awaiting OEB approval. A draft of the revised CDPP Standards may be found in Attachment 4 (Hydro One) and Attachment 5 (HOSSM). As a result of these changes, the group outlier standard will replace size of load with type of supply configuration (single-

[11] The group outlier standard establishes performance metrics for groups of customers depending on the size of their average station gross load in MW (defined as the total energy delivered or generated at a customer site in MWh divided by 8760 hours). The outlier standard is based on four customer groupings of: (i) 0 to 15 MW, (ii) greater than 15 up to 40 MW, (iii) greater than 40 to 80 MW, and (iv) greater than 80 MW. For more information, see Attachment 2 to this exhibit.

circuit or multi-circuit). It will maintain a four-band approach for single-circuit-supplied DPs based on line length because DP performance is strongly correlated with these two factors. Future DP analysis will be based on this new group standard.

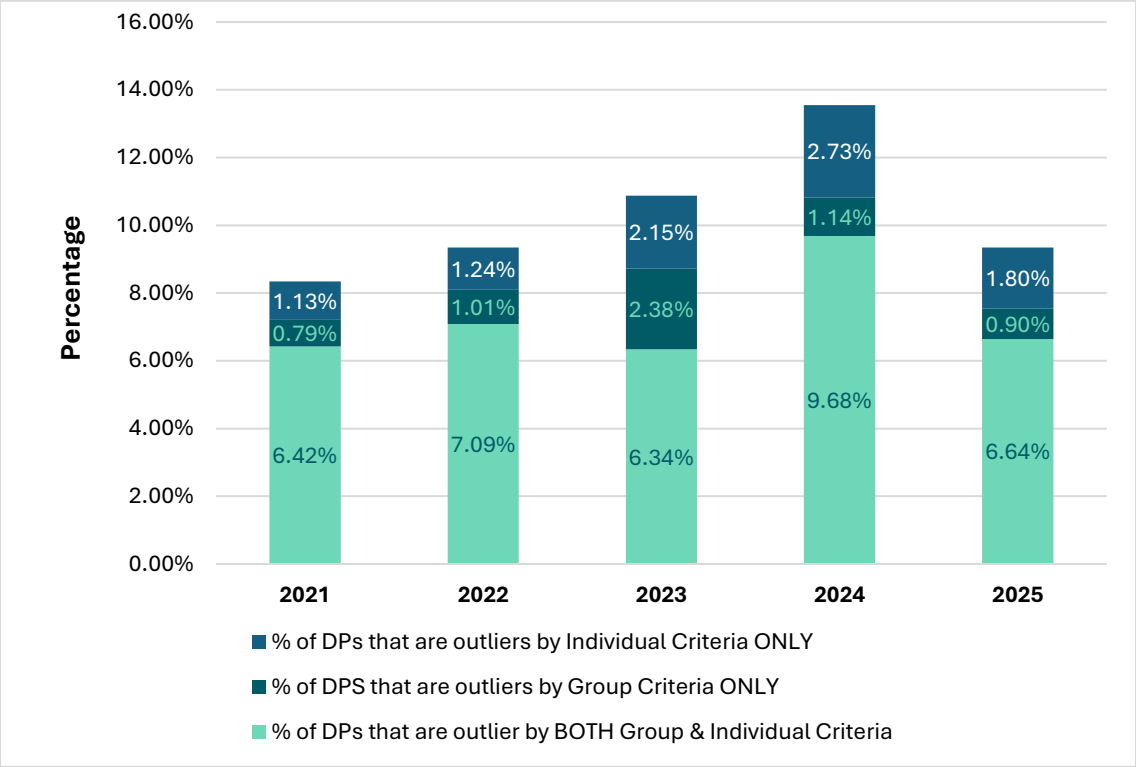


Figure 17: Transmission Load DP Outlier Percentage

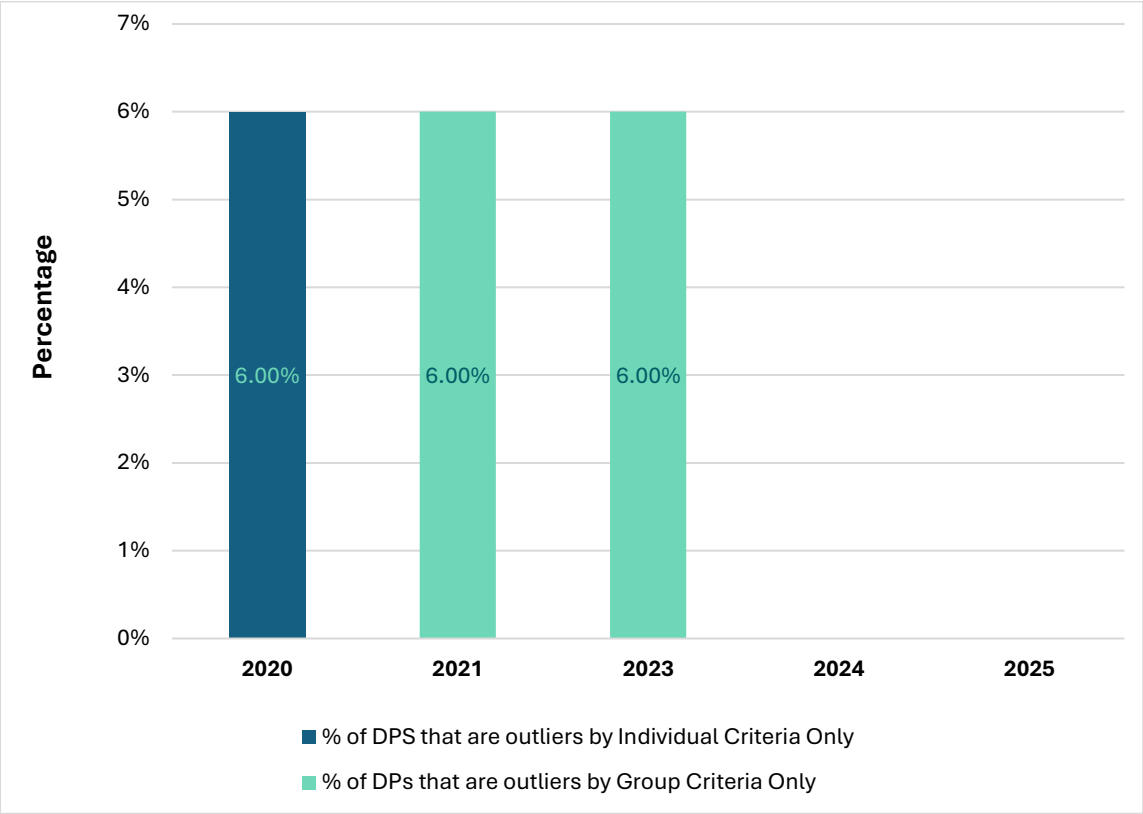


Figure 18: HOSSM Transmission Load DP Outlier Percentage

The DP outliers are analysed and considered for incorporation into future investment programs. Hydro One endeavours to keep the number of outliers at approximately 10% of its total DP population. However, this is not always possible. Some DPs are flagged as individual outliers even though they normally experience better reliability performance as measured by the group outlier standard. For example, a specific DP may have performed better than the relevant group standard but have an exceptionally strong historical baseline. Recent isolated events may therefore cause a temporary decline sufficient to classify the DP as an individual outlier. In most cases, such DPs return to non-outlier status in the following year without incremental investment. Hydro One considers this possibility when completing its assessments.

ATTACHMENTS: PERFORMANCE MEASUREMENT

Attachment 1: TSP First Nation Reliability Performance

Attachment 2: Customer DP Performance (CDPP) Standard

Attachment 3: Description of the Reliability Measures

Attachment 4: Revisions to CDPP Delivery Standards (Hydro One)

Attachment 5: Revisions to CDPP Delivery Standards (HOSSM)

SECTION 2.4 – ATTACHMENT 1 – TSP FIRST NATIONS RELIABILITY PERFORMANCE

1.0 INTRODUCTION

The majority of First Nations communities in Ontario are connected to the Hydro One distribution system and their reliability is discussed in Exhibit B-03-01, Section 3.11, D-SS-04, Attachment 1.[1] As of the end of 2025, the distribution lines servicing First Nations communities were supplied from 50 transmission lines, six direct connections to high voltage stations busses and 73 delivery points. This attachment to TSP Section 2.4 discusses the reliability associated with these transmission lines and delivery points, as well as the actions Hydro One is undertaking to improve reliability.

This attachment begins with a discussion of First Nations transmission reliability in both the Northern and Southern sub-systems. It then summarizes the actions that Hydro One Transmission is planning over the 2028–2032 period to improve transmission reliability for First Nations communities.

2.0 RELIABILITY PERFORMANCE

The reliability performance of the transmission delivery points that serve distribution-connected First Nations communities is shown in Table 1. As discussed in TSP Section 2.4, the reliability performance of individual delivery points is shaped to a great extent by the supply configuration and historical development of the provincial transmission network, under which loads larger than 75 MW were generally provided with a dual-line supply, while smaller loads were connected through a single-line supply.

[1] SPF Section 1.6, Attachment 5 also describes how Hydro One engaged with First Nations leadership and/or their representatives on their communities' electricity needs and preferences.

Table 1 - First Nations Reliability—Northern and Southern Sub-systems

Transmission System—Northern Sub-system (2021–2025 Performance)			
Transmission Reliability Index	Average Number of Transmission Connections per Year	Duration of Interruptions (Interruption Minutes per Transmission Connection)	Frequency of Interruptions (Interruptions per Transmission Connection)
First Nations	45.2	173.9	4.09
Transmission System—Southern Sub-system (2021–2025 Performance)			
Transmission Reliability Index	Average Number of Transmission Connections per Year	Duration of Interruptions (Interruption Minutes per Transmission Connection)	Frequency of Interruptions (Interruptions per Transmission Connection)
First Nations	26.4	7.9	0.65

Of the 73 delivery points supplying First Nations communities, 10 were outliers in 2025. This represents an approximately 44.5 per cent decrease in the percentage of outliers compared with the prior Application.

The majority of the 10 outlier delivery points are categorized as “group outliers” with respect to interruption duration. Under Hydro One’s Customer Delivery Point Performance (CDPP) Standards, approved in 2005, a group outlier is triggered when the three-year rolling average of a delivery point’s performance exceeds the applicable minimum threshold for its load-size group or band.

The use of a three-year rolling average can cause an isolated event, such as an extreme weather event, to result in a delivery point being identified as a group outlier for an extended period. As a result, group-outlier status is not always indicative of ongoing delivery point performance. To address this limitation and align with the approach used for Individual Standards, the OEB approved changes to the Group Standard on November 27, 2025 (EB-2021-0307). Under the revised approach, a delivery point is triggered when its performance falls below the minimum CDPP Standard for two consecutive years, replacing the three-year rolling average methodology.

In addition, the OEB approved replacing “load size” with “supply configuration” (i.e., single-circuit or multi-circuit) as the primary grouping factor and maintaining a four-band structure for single-circuit-supplied delivery points based on line length. These changes reflect that delivery point performance is more strongly correlated with supply configuration and line length than with load size.

Since the Transmission System Code was introduced more than 20 years ago, customers have had the option to choose between single- and double-circuit supply, with associated infrastructure costs recovered either through rates or capital contributions. In northern regions, where locations are remote and transmission lines are significantly longer, infrastructure costs are much higher. As a result, customers in these areas typically opt for single-circuit supply because dual-circuit alternatives are often cost-prohibitive.

Most delivery points serving First Nations communities in the Northern sub-system are supplied by long, single-circuit 115 kV lines that traverse heavily treed areas. In 2025, the Northern sub-system serving First Nations communities contained 41 single-circuit-supplied delivery points and five dual-circuit-supplied delivery points. Of the 10 outlier delivery points identified, seven, or 70 per cent, are in the Northern sub-system, and all are radially supplied by long, single circuits. Because of their supply configuration, single-circuit-supplied delivery points are more susceptible to interruptions when the circuit supply is interrupted. Furthermore, repairs can take longer because of rugged terrain, heavily treed areas, extreme weather conditions, and lines located away from highways. In many cases, interruptions occur in remote locations that require longer travel times and are less accessible than locations near staffed centres. Additionally, locating a fault can take longer during adverse weather conditions.

Circuit length is also strongly correlated with delivery point reliability. Of the 10 outlier delivery points, six, or 60 per cent, are radially supplied by circuits longer than 90 km. The longest circuit supplying an outlier delivery point is the 278 km E1C circuit in the Northern sub-system. Longer circuits are more likely to experience an interruption because of greater exposure to weather and other environmental factors.

In contrast, most Southern sub-system delivery points are served by dual-circuit 230 kV lines. This 230 kV infrastructure is also primarily constructed of steel and is more resilient. In the Southern sub-system, there were five single-circuit-supplied delivery points and 22 multi-circuit-supplied delivery points serving First Nations communities. Of the 10 outlier delivery points, only three, or 30 per cent, are in the Southern sub-system. In the few cases where multi-circuit-supplied delivery points are outliers, the outlier status is generally temporary because it results from an isolated incident and the underlying issue is quickly rectified. Historically, these delivery points have demonstrated strong reliability performance.

Figure 1 shows the 2025 reliability performance of the transmission delivery points that serve First Nations communities in both the Northern and Southern sub-systems. The red line on the map illustrates the boundary between the two sub-systems.

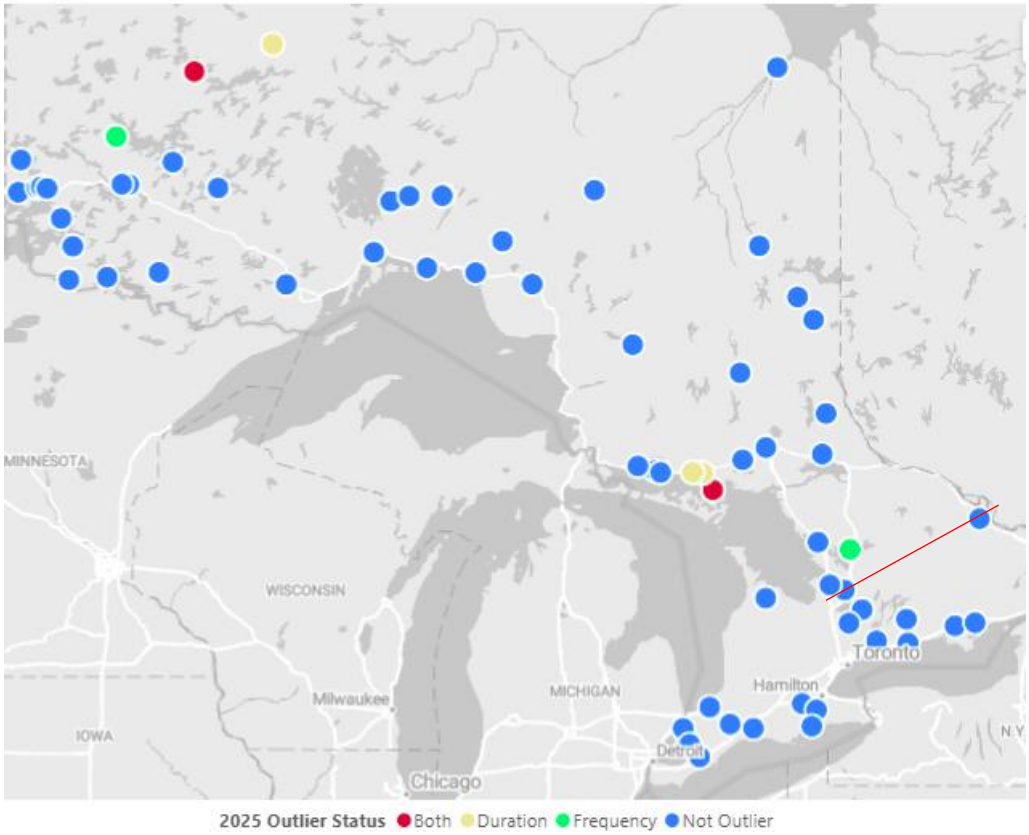


Figure 1: First Nations Delivery Point Outlier Status, 2025

3.0 WORK ADDRESSING FIRST NATIONS RELIABILITY

This section discusses the work that Hydro One is undertaking to address reliability issues affecting First Nations communities.

The number of outlier delivery points serving First Nations communities decreased from 14 in 2024 to 10 in 2025. Hydro One is currently assessing the performance of the 2025 outlier delivery points, including the root causes associated with their outlier status, to determine whether additional investments are required. As the assessment of the 2025 outlier delivery points is ongoing, the work described in Section 3.1 is based primarily on the delivery points identified as outliers in 2024. Section 3.2 describes broader investments and maintenance activities that support the reliability of supply to First Nations communities.

3.1 WORK ADDRESSING OUTLIER DELIVERY POINTS

Of the 10 outlier delivery points in 2025, seven are supplied by long, radial, single-circuit 115 kV lines. The delivery points supplied by circuits E1C (e-w), S2B (e-w), and A4L, with lengths of 278 km, 209 km, and 150 km, respectively, are exposed to more interruptions because of their radial supply configuration, longer circuit lengths, heavily treed rights-of-way, rugged terrain, and severe weather conditions. As a result, delivery points supplied by these circuits have been identified as outliers more than once in recent years. Hydro One has plans in place to address the reliability of the delivery points supplied by these circuits. The remaining outlier delivery points resulted from isolated events, such as inclement weather or equipment failure, that Hydro One subsequently addressed.

Accordingly, Hydro One plans to refurbish portions of the A4L and E1C circuits by 2031, as described in TSP Section 2.11, T-SR-13. The refurbishment is expected to improve the condition and performance of the circuits and reduce the risk of failures. In addition, Wataynikaneyap Power LP energized an approximately 300 km, single-circuit 230 kV transmission line between the Dinorwic and Pickle Lake areas in 2022. This line created a loop with the E1C line, establishing a second source of supply and providing greater operational flexibility during planned and unplanned outages on E1C. It also allows Hydro

One to perform repairs on E1C while improving reliability for delivery points in the area. To further enhance reliability in the area, a new E1C circuit configuration is scheduled to be in service by the end of 2026. This configuration will establish a new normally open end point at Pickle Lake SS using a circuit breaker with remote-control capability. With the addition of a new shunt reactor as part of this investment, the configuration will provide two high-voltage sources of supply to support operational continuity.

Hydro One is also planning transmission reinforcement in the North. For example, Hydro One will be responsible for developing and constructing the new Greenstone Transmission Line, a 230 kV transmission line between Longlac Transformer Station in Geraldton and Nipigon Generating Station that will connect to the East–West Tie near Nipigon Bay by 2032. Once constructed, the Greenstone Transmission Line will provide immediate reliability benefits to the region, including the delivery points along A4L, because A4L will no longer operate as a radial line. In addition, the proposed Wawa–Timmins Power Line will be a 500 kV single-circuit transmission line connecting Wawa TS and Porcupine TS in Timmins. These two transmission lines will further reinforce the North, support continued growth, and improve reliability for First Nations communities.

The following projects are intended to address reinforcement needs affecting specific outlier delivery points:

- E1C, E. Fall x S. Fall and Etrcn x C. River, Transmission Line Refurbishment (T-SR-13)
- A4L, Beardmore x Longlac TS, Transmission Line Refurbishment (T-SR-13)
- Greenstone Transmission Line Project (T-SS-10)
- Muskoka TS: Component Replacement (T-SR-03)
- Owen Sound TS: T5 and Component Replacement (T-SR-01)
- Manitoulin Voltage Reinforcement Project (T-SS-12)

3.2 BROADER WORK SUPPORTING FIRST NATIONS DELIVERY POINTS

In addition to the projects affecting outlier delivery points, Hydro One is undertaking the following projects which will also help to maintain the reliability of supply for First Nations delivery points:

- A8/A9K, Structure 141 x Kirkland Lake TS, Transmission Line Refurbishment (T-SR-13)
- Beaverton TS: Component Replacements (T-SR-03)
- Crystal Falls TS: Component Replacement (T-SR-03)
- Edgeware TS: T1, T2 and Component Replacement (T-SR-03)
- Jarvis TS: T3, T4 and Component Replacement (T-SR-03)
- K4, Kirkland Lake TS x Matachewan Junction, Transmission Line Refurbishment (T-SR-13)
- Kenora TS: Component Replacement (T-SR-01)
- Lambton TS: T7/T8, T5/T6 and DESN Replacement (T-SR-03)
- Longwood TS: Component Replacement (T-SR-03)
- North Shore Link: Mississagi x Third Line Reinforcement (T-SS-11)
- Orillia TS: T2 Transformer Replacement (T-SR-03)
- Parry Sound TS: Component Replacement (T-SR-03)
- Wallaceburg TS: Conversion from 115 kV to 230 kV (T-SA-11)
- Waubaushene TS: Replace T5 and T6 and Rebuild DESN (T-SR-03)
- Whitedog Falls SS: Component Replacement (T-SR-01)

Hydro One also undertakes ongoing inspection, maintenance, and vegetation-management activities across the transmission system. These activities include line clearing, brush control, asset condition assessments, and ground and helicopter patrols. This work is particularly important for transmission facilities in remote and heavily treed areas, where vegetation exposure, severe weather, rugged terrain, and limited accessibility can increase both the likelihood and duration of interruptions.

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SECTION 2.4 – ATTACHMENT 2 – CUSTOMER DELIVERY POINT PERFORMANCE (CDPP) STANDARD

1.0 INTRODUCTION

The Transmission System Code (TSC) requires transmitters to develop performance standards at the Customer Delivery Point (CDPP)[1] level, consistent with system-wide standards, that:

- reflect typical transmission system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- reflect historical performance at the customer delivery point level;
- establish acceptable bands of performance at the customer delivery point level for the transmission system configurations, geographic area, load, and capacity levels;
- establish triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;
- establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken; and
- establish any circumstances in which the performance standards will not apply.

On July 25, 2005, the OEB issued its Decision and Order (RP-1999-0057/EB-2002-0424) and approved Hydro One's proposed CDPP Standards, subject to a number of changes directed by the OEB. The CDPP Standards apply to all existing and new transmission load customers, including customers that signed a connection cost recovery agreement before the May 1, 2002, market opening.

[1] A Delivery Point (DP) is defined as a point of connection between a transmitter's transmission facilities and a customer's facilities.

Sections 2.0–2.2 of this document describe the CDPP Standards approved by the OEB in 2005.

Proposed Revisions to the CDPP Standards

In 2021, the OEB initiated a Reliability and Power Quality Review (RPQR) consultation with stakeholders. In 2023, the RPQR Transmission Subgroup was formed to discuss potential changes to the reliability framework for transmitters. The Subgroup recommended changes to the existing CDPP Standards, mainly to the Group Outlier Standard, and the addition of a new section on power quality. The OEB approved the changes on November 27, 2025, in a letter to transmitters (EB-2021-0307). On March 1, 2026, as required by the OEB, Hydro One filed revised CDPP Standards reflecting these changes and is awaiting OEB approval. Drafts of the revised CDPP Standards are provided in Attachment 4 for Hydro One and Attachment 5 for HOSSM.

A key revision is the change to the Group Outlier Standard. Under Hydro One's CDPP Standards approved in 2005, a delivery point becomes a group outlier when its three-year rolling average performance falls below the minimum CDPP Standard for its load-size group or band.

Because the existing trigger uses a three-year rolling average, a single isolated event, such as an extreme weather incident, can cause a delivery point to remain a group outlier for at least three years. Such cases may not indicate the delivery point's ongoing performance. To address this issue and align the Group Outlier Standard with the approach used for the Individual Standards, the OEB approved changes (EB-2021-0307) under which the trigger occurs when a delivery point's performance exceeds the corresponding Group threshold in two consecutive years, replacing the three-year rolling average. The OEB also approved replacing load size with supply configuration—single-circuit or multi-circuit—as the basis for the Group Outlier Standard. The revised standard maintains four bands for single-circuit delivery points based on line length because delivery point performance is strongly correlated with supply configuration and line length.

2.0 DELIVERY POINT RELIABILITY STANDARDS

The approved CDPP Standards consist of two components:

- Group CDPP Standards that relate the reliability of supply to the size of the load being served at the delivery point; and
- Individual CDPP Standards that maintain a customer's historical performance at an individual delivery point.

The applicable triggers identify Group and Individual performance outliers and initiate technical and financial evaluations to determine the root cause of the unreliability and any remedial action required to improve reliability. The CDPP Standards and triggers for each component are summarized in Section 2.1.

2.1 PERFORMANCE STANDARDS BASED ON LOAD SIZE: GROUP CDPP STANDARDS

The CDPP Standards and associated triggers are based on the size of the load served at each delivery point. For this purpose, load means the delivery point's total average station gross load[2], measured in megawatts. As shown in Table 1, the CDPP Standards divide delivery points into four load-size bands: 0–15 MW, greater than 15 MW up to 40 MW, greater than 40 MW up to 80 MW, and greater than 80 MW.

[2]Total Average Station Gross Load (MW) = (Total Energy Delivered to the Station (MWh) + Total Energy Generated at the Station Site (MWh)) / 8760 hours.

Table 1 - Customer Delivery Point Performance Standards Based on Load Size

Performance Measure	Customer Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0–15 MW		>15–40 MW		>40–80 MW		>80 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (outages/year)	4.1	9.0	1.1	3.5	0.5	1.5	0.3	1.0
DP Interruption Duration (minutes/year)	89	360	22	140	11	55	5	25

These CDPP Standards are based on performance from 1991 to 2000, measured by the frequency and duration of all momentary and sustained interruptions[3] caused by forced outages. The calculation excludes extraordinary events that had an "excessive" impact on the transmission system, including the 1998 ice storm and the 2003 blackout.

2.1.1 CRITERIA TO IDENTIFY PERFORMANCE OUTLIERS UNDER THE GROUP CDPP STANDARDS

Hydro One uses the minimum performance standard for each of the four load-size bands as a trigger to identify Group performance outliers. A delivery point is identified as an outlier when its three-year rolling average performance falls below the minimum CDPP Standard for the applicable load-size band or when a delivery point customer requests an analysis. Once an outlier is identified, Hydro One, in consultation with affected customers, initiates technical and financial evaluations to determine the root cause of the unreliability and any remedial action required to improve reliability.

[3]Momentary interruption is any forced interruption to a delivery point lasting less than one minute and a sustained interruption is any interruption to a delivery point lasting one minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Hydro One components causing load loss. Interruptions caused by Hydro One's customers are recorded but not charged against Hydro One's reliability performance for the customer initiating the interruption but are charged against Hydro One's reliability performance for other interrupted customers.

2.1.2 PERFORMANCE STANDARDS TO MAINTAIN HISTORICAL DELIVERY POINT PERFORMANCE: INDIVIDUAL CDPP STANDARDS

The Individual CDPP Standards are intended to maintain the historical reliability performance of each customer delivery point. They identify deteriorating reliability trends regardless of whether the delivery point performs satisfactorily under the Group CDPP Standards in Section 2.1. For each delivery point, Hydro One establishes frequency and duration triggers for forced momentary and sustained interruptions using the delivery point's average performance from 1991 to 2000 plus one standard deviation, referred to as the historical baseline. The historical baseline excludes extraordinary events that had an "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skewed the historical trend of the measure. Examples include the 1998 Eastern Ice Storm, the 2003 Northeast Blackout, the 2013 GTA flood, and the 2018 Ottawa-area tornado. For a delivery point placed in service after 1991, the in-service year is the first year of the 10-year period used to establish the performance baseline.

2.1.3 CRITERIA TO IDENTIFY PERFORMANCE OUTLIERS UNDER THE INDIVIDUAL CDPP STANDARDS

A delivery point is identified as an Individual performance outlier and a candidate for remedial action when its frequency or duration performance is worse than its historical baseline for two consecutive years. Hydro One then initiates technical and financial evaluations with affected customers to determine the root cause of the unreliability and the remedial measures required to restore the delivery point's historical reliability performance.

2.1.4 REMEDIAL COSTS TO ADDRESS GROUP AND INDIVIDUAL PERFORMANCE OUTLIERS

For Group and Individual performance outliers, Hydro One will cover the remedial costs of restoring and sustaining the inherent reliability performance of the existing assets to their original design level. These costs include appropriate asset sustainment costs, ongoing maintenance costs, and costs associated with asset refurbishment or replacement. These expenditures are made on an ongoing basis, consistent with "good

utility practices," irrespective of actual delivery point performance or whether a delivery point is a performance outlier. No customer contribution formula is required for these normal sustainment expenditures.

For Individual performance outliers, Hydro One will restore the delivery point to its historical level of performance. Hydro One's remedial work will not include capital reliability improvements that significantly enhance the reliability of supply relative to the reliability inherent in the original system design or supply configuration.

For Group performance outliers, Hydro One's incremental investment to improve an outlier's performance beyond its original design level will be limited to the present value of three years of transformation and/or transmission line connection revenue associated with the delivery point. Affected delivery point customers will contribute any funding shortfall required to improve delivery point reliability performance. Where specific transmission facilities serve two or more customers with outlier performance, Hydro One will approach all affected customers to determine their willingness to contribute jointly to the reliability improvements.

Cost responsibility for these investments will be consistent with the TSC, specifically:

1. Hydro One will not attribute costs associated with network investment to any customer, and any variance from this approach requires a determination by the OEB;
2. The costs of preparing the final estimate for reliability improvements required to address performance outliers are the only portion of the technical and financial evaluation included in the cost of the remedial work; and
3. Where a customer contribution is required to improve or expand the transmission system to correct outlier performance, the customer will be given contracting privileges consistent with those applicable to contestability for new customer connections. In addition, affected delivery point customers are responsible for all costs associated with any new or modified facilities required on lines and stations they own to improve reliability. These financial and cost-sharing arrangements will

be detailed in a connection and cost recovery agreement with the affected customers.

2.2 PROCESS TIMELINES TO ADDRESS PERFORMANCE OUTLIERS

Figure 1 and Table 2 set out the process and associated timelines for addressing Group and Individual performance outliers and determining the preferred course of action.

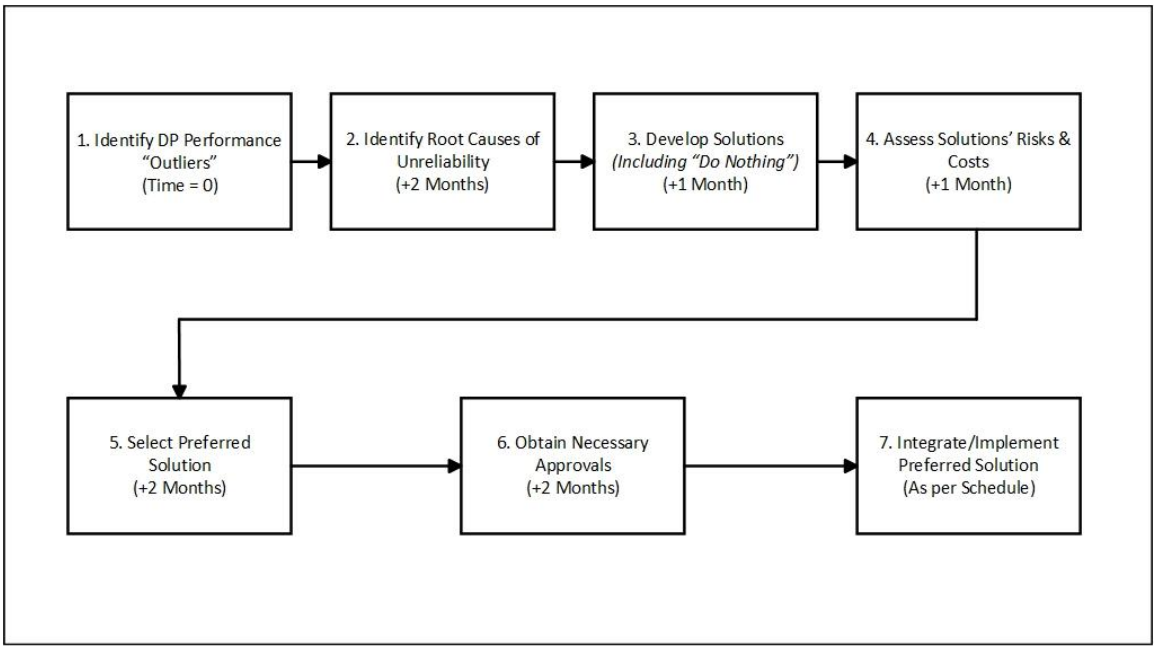

Figure 1: Performance Outlier Process Map

Table 2 - Performance Outlier Process

Step	Timeline	Action
1	0	Hydro One annually identifies delivery point performance outliers under the Group and Individual CDPP Standards. Hydro One will notify customers supplied from these delivery points and solicit feedback on their reliability-of-supply issues and concerns.
2	< 2 months	Hydro One will determine the root causes of unreliability associated with each performance outlier identified in Step 1.
3	< 1 month	Hydro One will develop solutions to address performance outliers, including: 1. work to restore and sustain the inherent reliability performance of the existing assets to their original design level; and 2. for Group performance outliers, additional capital improvements required to bring an outlier within the standard beyond its original design level. Hydro One will discuss the proposed solutions with affected customers.
4	< 1 month	Hydro One will determine the costs and assess the risks of the solutions, including any customer capital contributions required for option 2 in Step 3. Hydro One will present these costs to customers for their review and assessment.
5	< 2 months	Hydro One and the affected customers will select the preferred option. Where appropriate, the customers will indicate whether they intend to proceed with capital improvements that involve the customer contributions identified in option 2 in Step 3.
6	< 2 months	Hydro One and the affected customers will obtain the necessary approvals to proceed with the preferred solutions to address performance outliers.
7	Agreed Schedule	Hydro One will integrate the solutions into its work programs and implement them according to a mutually agreed schedule.

After Hydro One completes work to restore a delivery point's performance to the applicable standard, it continues to monitor the delivery point in the following year. If subsequent performance indicates that the standard has not been met, Hydro One will review the completed work and identify corrective action. Hydro One will not ordinarily wait another three years before beginning a new technical and financial evaluation. Hydro One reviews customer delivery point performance annually, regardless of investment history.

The outlier assessment process under the revised CDPP Standards is similar to the process described above. The revised process clarifies the timelines and the points at which customers are engaged. The overall outlier assessment and mitigation-plan

development process takes approximately 6–8 months for all outliers. Where a capital contribution may be required, Hydro One will discuss the proposed solutions with affected customers.

Hydro One continues to maintain strong delivery point performance and mitigate delivery point outliers while the transmission system grows through the addition of new delivery points each year. Although this expansion supports increasing demand and enhances overall system reliability, it also increases exposure to incidents, some of which are outside the reasonable control of utilities or are not cost-effective to design against. Severe weather is a key example. The 2022 derecho in Eastern Ontario caused prolonged interruptions at several delivery points, particularly those supplied by single circuits.

Since the TSC was introduced more than 20 years ago, customers have had the option to choose between single and double-circuit supply, with the associated infrastructure costs recovered through rates or a capital contribution. Infrastructure costs are significantly higher in northern regions because locations are remote and transmission lines are longer. As a result, customers in these areas typically choose single-circuit supply because dual-circuit alternatives are often cost-prohibitive.

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SECTION 2.4 – ATTACHMENT 3 – DESCRIPTION OF THE RELIABILITY MEASURES

DELIVERY POINT

The delivery point is the point of supply where energy from the bulk electricity system (115 kV and above) is transferred to the distribution system or a retail customer. This point is generally taken as the low-voltage bus at step-down transformer stations. For customer-owned stations supplied directly from the transmission system, the delivery point is generally the interface between the utility-owned equipment and the customer's equipment.

FORCED INTERRUPTION

A forced interruption is a delivery point interruption due to a disconnection resulting from an unplanned event.

PLANNED INTERRUPTION

A planned interruption is a delivery point interruption due to a disconnection at a selected time for the purpose of construction or preventive maintenance.

MOMENTARY INTERRUPTION

A momentary interruption is any loss of supply voltage to a delivery point that is less than one minute in duration. These interruptions are generally restored by automatic reclosure facilities and last only a few seconds.

SUSTAINED INTERRUPTION

A sustained interruption is any loss of supply voltage to a delivery point that has a duration of one minute or more.

AVERAGE FREQUENCY OF DELIVERY POINT INTERRUPTIONS

Average Frequency of Delivery Point Interruptions indicates the average number of interruptions experienced by customers and is presented as interruptions per delivery point per year. It is expressed mathematically as:

$$\text{Average Frequency of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N}(M_i + S_i)}{N}$$

Where:

- M_i is the total number of momentary interruptions experienced at delivery point i in a given year.
- S_i is the total number of sustained interruptions experienced at delivery point i in a given year.
- N is the equivalent total number of delivery points in a given year.

Interruption-frequency indicators are used in other regulatory jurisdictions. Transmission service providers in Alberta, Australia, the UK, New Zealand and Sweden use an interruption frequency indicator. Additionally, Electricity Canada tracks the frequency of delivery point interruptions among its transmission member utilities.

The average frequencies of sustained and momentary delivery point interruptions can also be presented separately.

AVERAGE DURATION OF DELIVERY POINT INTERRUPTIONS

Average Duration of Delivery Point Interruptions is the average time during which customers experience an interruption from the transmission system and is presented as minutes per delivery point per year. It is expressed mathematically as:

$$\text{Average Duration of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N}(\mathrm{D}_i)}{N}$$

Where:

- D_i is the total effective interruption duration of sustained interruptions experienced at delivery point i in a given year.
- N is the equivalent total number of delivery points in a given year.

Interruption-duration indicators are used in other regulatory jurisdictions. Transmission service providers in Alberta, Australia, the UK, New Zealand and Sweden use an interruption duration indicator. Additionally, Electricity Canada tracks the duration of delivery point interruptions among its transmission member utilities.

UNSUPPLIED ENERGY

Unsupplied Energy is an indicator of the total energy not supplied to customers due to delivery point interruptions. To permit comparisons among utilities of different sizes, unsupplied energy is normalized by system peak load. This measure is defined as the Delivery Point Unreliability Index (DPUI). It is expressed mathematically as:

$$\text{Delivery Point Unreliability Index} = \frac{\sum_{i=1}^{N} U_i \ x \ 60 \, \text{min/hr}}{Pk}$$

Where:

- U_i is the total unsupplied energy, expressed in MWh, at delivery point i in a given year.
- P_k is the system peak load in the year, expressed in MW.
- N is the equivalent total number of delivery points in a given year.

The normalized unsupplied energy measure is expressed in system minutes. Transmission companies in Canada, the United States, and Europe use indicators of this type to assess transmission system reliability.

TRANSMISSION SYSTEM UNAVAILABILITY

Transmission System Unavailability captures the total duration of transmission equipment out of service due to forced outages. Transmission System Unavailability due to forced outages can be presented at the system level or divided into (1) Transmission Line Unavailability and (2) Station Equipment Unavailability, consistent with Electricity Canada's reliability benchmarking programs.

These indicators are expressed mathematically as:

$$\text{Total System Unavailability} = \left(\frac{\sum_{i=1}^{N_M} F_{M_i}}{\mathrm{T_M}} \right) \mathrm{x}\, 100\%$$

Where:

- F_{Mi} is the annual forced-outage duration, in hours, for major transmission equipment, including station equipment and transmission lines, M_i.
- T_M is the inventory, expressed in hours, of all in-service major transmission equipment, including station equipment and transmission lines.
- N_M is the total number of items of in-service major transmission equipment, including station equipment and transmission lines.

$$\text{(1) Transmission Line Unavailability} = \left(\frac{\sum_{i=1}^{N_L} F_{L_i}}{\mathrm{T_L}} \right) \mathrm{x}\, 100\%$$

Where:

- F_{Li} is the annual forced-outage duration, in hours, due to transmission-line-related outages of circuit L_i.
- T_L is the inventory, expressed in 100 km-hours, of all in-service transmission circuits.
- N_L is the total number of in-service transmission circuits.

(2) Station Equipment Unavailability $= \left(\frac{\sum_{i=1}^{Ns} F_{S_i}}{\mathrm{T_S}} \right) \mathrm{x}\, 100\%$

Where:

- F_{Si} is the annual forced-outage duration, in hours, for major transmission station equipment item S_i.
- T_S is the inventory, expressed in hours, of all in-service major transmission station equipment.
- N_S is the total number of items of in-service major transmission station equipment.

These indicators track the extent to which the transmission system, including transmission circuits and substation equipment, is unavailable. They focus on the aspects of transmission service within Hydro One's control and place the effect of outages in the context of overall transmission-system availability. Transmission companies in Canada, the United States, and Europe use indicators of this type to assess transmission-system reliability.

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BY EMAIL AND RESS

February 27, 2026

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2021-0307 - Changes to Improve the Transmission Framework for Reliability and Power Quality - Hydro One Networks Inc. Transmitter Standards Document

In accordance with the Ontario Energy Board's (OEB) expectations outlined in the OEB's November 27, 2025 letter in this proceeding (the November 27 Letter), Hydro One Networks Inc. (Hydro One) is providing the OEB a revised Transmitter Standards Document that is consistent with the changes discussed in the November 27 Letter.

An electronic copy of these performance standards has been filed through the OEB's Regulatory Electronic Submission System.

Sincerely,

Pasquale Catalano

Hydro One Networks Inc.

Customer Delivery Point Performance Standards (CDPPS) and Power Quality

Prepared by: Hydro One Networks Inc.

Last Revised: February 27, 2026

(Supersedes: Customer Delivery Point Performance Standards, February 7, 2008)

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1.0 INTRODUCTION

The Transmission System Code (TSC) requires transmitters to develop Customer Delivery Point Performance ("CDPP")[1] Standards at the customer delivery point level, consistent with system wide standards, that:

- reflect typical transmission system configurations that consider the historical development of the transmission system at the customer delivery point level;
- reflect historical performance at the customer delivery point level;
- establish acceptable bands of performance at the customer delivery point level for the transmission system configurations, geographic area, circuit length, etc.;
- establish a process to evaluate delivery point performance and triggers that would initiate technical evaluation by the transmitter and financial evaluation, where required, in consultation with customers, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;
- establish the steps to be taken based on the results of any evaluation that has been triggered, as well as the circumstances in which such steps need not be taken;
- establish any circumstances in which the performance standards will not apply.

On May 3, 2002, Hydro One proposed its first CDPP Standards to meet the requirements of the TSC with the Ontario Energy Board ("OEB") for review and approval. Subsequently, on September 8, 2004, as a result of stakeholder comments received, Hydro One filed amendments to its original CDPP Standards submission. On July 25, 2005, the OEB issued its Decision and Order (RP-1999-0057/EB-2002-0424) which approved Hydro One's proposed CDPP Standards subject to a number of changes directed by the OEB.

In 2021, the OEB initiated a Reliability and Power Quality Review (RPQR) consultation with stakeholders. In 2023, the OEB RPQR formed a Subgroup for Transmission ("the Subgroup"). One of the objectives of this group was to discuss potential changes to the current reliability framework for transmitters. The Subgroup recommended changes to the existing CDPP standards to the OEB, mainly to the Group Outlier standard (described in section 2.1 of this document), and adding a new section to this document related to Power Quality (described in section 3.0 of this document). The OEB approved these changes on November 27, 2025 (EB-2021-0307). On February 27, 2026, Hydro One filed amendments to its previous CDPP Standards submission to reflect these changes.

[1] A Delivery Point is defined as a point of connection between a transmitter's transmission facilities and a customer's facilities.

The CDPP Standards apply to all transmission load customers (including customers that have signed a Connection Cost Recovery Agreement prior to May 1, 2002, market opening).

2.0 DELIVERY POINT RELIABILITY STANDARDS

The approved CDPP Standards consist of two components: (1) Group CDPP Standards that relate the reliability of supply to the supply configuration (single circuit versus multi circuit) and supply circuit length for single circuits and (2) Individual CDPP Standards that maintain a customer's individual historical delivery point performance. Triggers for each component are used to identify performance "outliers" to initiate technical and financial evaluations to determine the root cause of unsatisfactory performance and if remedial action is required to address the root cause. The CDPP Standards and triggers for each component are summarized below.

2.1 Group CDPP Standards: Performance Standards Based on Supply Configuration and Circuit Length

For this component, the CDPP Standards and the associated triggers are based on the predominant supply configuration (single circuit versus multi circuit) and circuit length for single supply circuits since delivery point ("DP") performance is strongly correlated to these two factors. For single circuits, the CDPP Standards vary with the length of the supply circuit in ranges of 0 to 40 km, greater than 40 up to 90 km, greater than 90 up to 150 km, and greater than 150 km, as shown in Table 1 below.

Table 1
Customer Delivery Point Performance Group Standards Based on Supply Configuration and Circuit Length

	Customer Delivery Point Performance Group Standards				
	Multi-Circuit Supplied DPs	Single Circuit Supplied DPs			
Supply Circuit Length (L in km)	**N/A**	**L≤40 km**	**40<L≤90 km**	**90<L≤150 km**	**L>150 km**
DP Frequency of Interruptions Threshold (# interruptions/DP/yr)	1	2	5	7	9
DP Interruption Duration Threshold (interruption minutes/DP/yr)	58	200	300	380	854

These CDPP Standards are based on historical 2013-2022 performance data as measured by the average frequency and duration of all forced (momentary and sustained) interruptions[2] plus one standard deviation, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical performance. To avoid this, such events are excluded from the calculation[3].

For any new DP that is added to the system, the DP performance is assessed based on the corresponding band within the Group CDPP Standards that applies (i.e., corresponding threshold for multi or single circuit and appropriate length if single circuit). For new customers connecting to an existing DP, the existing Group CDPP Standards will apply immediately.

[2] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any forced interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Hydro One components causing load loss. Interruptions caused by Hydro One's customers are recorded but not charged against Hydro One's reliability performance for the customer initiating the interruption but are charged against Hydro One's reliability performance for other interrupted customers.

[3] Such as the 2013 GTA flood and 2018 Ottawa Area tornado.

2.1.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Group CDPP Standards

The minimum Group CDPP standards of performance (see Table 1), for both frequency and duration of interruptions, are to be used as triggers by Hydro One in identifying Group Outliers. The trigger occurs when the frequency and/or duration of interruptions at a DP exceeds its corresponding Group threshold in two consecutive years (and therefore is identified as a Group Outlier) or when a DP customer requests an analysis. When a Group outlier is identified, it is considered a candidate for remedial action. In such cases, Hydro One will initiate a technical evaluation to determine the root cause of the unsatisfactory performance and any remedial actions to address it. Hydro One will also initiate a financial evaluation for remedial actions, where required, in consultation with affected customers.

2.2 Individual CDPP Standards: Performance Standards to Maintain Historical Delivery Point Performance

For this component, the CDPP Standards are intended to maintain the historical reliability performance levels at each customer DP. This is done by identifying customer DPs with deteriorating trends in reliability performance, irrespective of whether they are satisfactory performers under the Group CDPP Standards (Section 2.1 above). To identify customer DPs with deteriorating trends in reliability performance, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is established for each DP based on that DP's historical 2013-2022 average performance, plus one standard deviation (the "Historical Baseline"). The Historical Baseline excludes outages resulting from extraordinary events[4] that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, skew the historical performance. To avoid this, such events are excluded from the calculation.

For any new DP that is added to the system, the DP performance is assessed based on the Group CDPP Standards for the first four calendar years after being placed in-service. Temporary Individual baselines are then created after the DP has been in-service for 5 calendar years and are finalized when it has been in-service for 10 years consistent with the method for the Historical Baseline. For new customers connecting to an existing DP, the existing Individual Historical Baseline for the DP will apply immediately.

Also, for DPs that have not experienced any interruptions, or zero interruption duration occurred during the 10-year period used for establishing a DP's Individual Historical Baseline, the corresponding frequency and/or duration baselines for the DP would be

[4] Such as the 2013 GTA flood and 2018 Ottawa Area tornado.

zero. In such cases, these DPs would be an Individual outlier if it experiences any number of interruptions for two consecutive years.

2.2.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Individual CDPP Standards

The minimum Individual CDPP standards of performance, for both frequency and duration, are to be used as triggers by Hydro One in identifying Individual Outliers. The trigger occurs when the frequency and/or duration of interruptions exceeds the Historical Baseline in two consecutive years (and therefore is identified as an Individual Outlier). When an Individual outlier is identified, it is considered a candidate for remedial action. In such cases, Hydro One will initiate a technical evaluation to determine the root cause of the unsatisfactory performance and any remedial actions required to restore reliability to the Historical Baseline of the DP's performance. Hydro One will also initiate a financial evaluation for remedial actions, where required, in consultation with affected customers.

2.3 Remedial Costs to Address Group and Individual Performance Outliers

For Group and Individual Performance Outliers, Hydro One will develop and undertake a feasible and cost-effective mitigation plan that is intended to improve the reliability performance of the existing assets as per its original design. For example, performance of DPs supplied by a single circuit will not be mitigated by planning a second circuit supply as that is highly cost prohibitive and a customer contribution would be required, consistent with the TSC. However, Hydro One continuously makes investments to maintain the transmission system and address reliability performance such as replacing aging infrastructure. These expenditures are made on an ongoing basis irrespective of whether a DP is an outlier or not which helps maintain or improve supply reliability.

Investments are reviewed as part of Hydro One's Outlier Assessment and Mitigation Process (refer to section 2.4). Many planned investments directly address the root cause of unsatisfactory DP performance and further action and incremental investment is typically not required. No customer contribution is required for these planned capital expenditures by Hydro One.. For Individual Performance Outliers where investments are required beyond Hydro One's planned investments, Hydro One will develop an economically feasible mitigation plan to improve DP performance to its original design. Hydro One will undertake the costs associated with this remedial work but will not include capital reliability improvements that require significant change to the original supply configuration to improve DP performance. In some cases, mitigation measures are

incremental to the original design because the DP supply characteristics have significantly changed over the years (e.g. new customer connections supplied by the DP). In these situations, a customer contribution may be required.

For Group Performance Outliers, Hydro One's level of incremental investment for improving the performance of an outlier beyond what was designed originally will be limited to the present value of three years' worth of combined transformation and transmission line connection revenue[5] associated with the DP. Any funding shortfalls for improving DP reliability performance will be made up by affected DP customers. In cases where specific transmission facilities are serving two or more customers in common with outlier performance, Hydro One will approach all affected customers to determine their willingness to contribute jointly to the reliability improvements.

Cost responsibility for any investment is to be consistent with the TSC. Where a customer contribution is required as part of the mitigation plan to improve DP performance, Hydro One will consult with the customer on the solution and execute Cost Recovery Agreements as needed. In addition, affected DP customers are responsible for all the costs associated with any new or modified facilities they own to improve their reliability performance.

[5] In the special case where a delivery point pays only network tariffs, transmission line connection tariffs are to be used as a proxy in the revenue calculation.

2.4 Outlier Assessment and Mitigation Process

The process and associated timelines that will be followed to address performance outliers – both for Group and Individual outliers – and determine the preferred course of action is provided below.

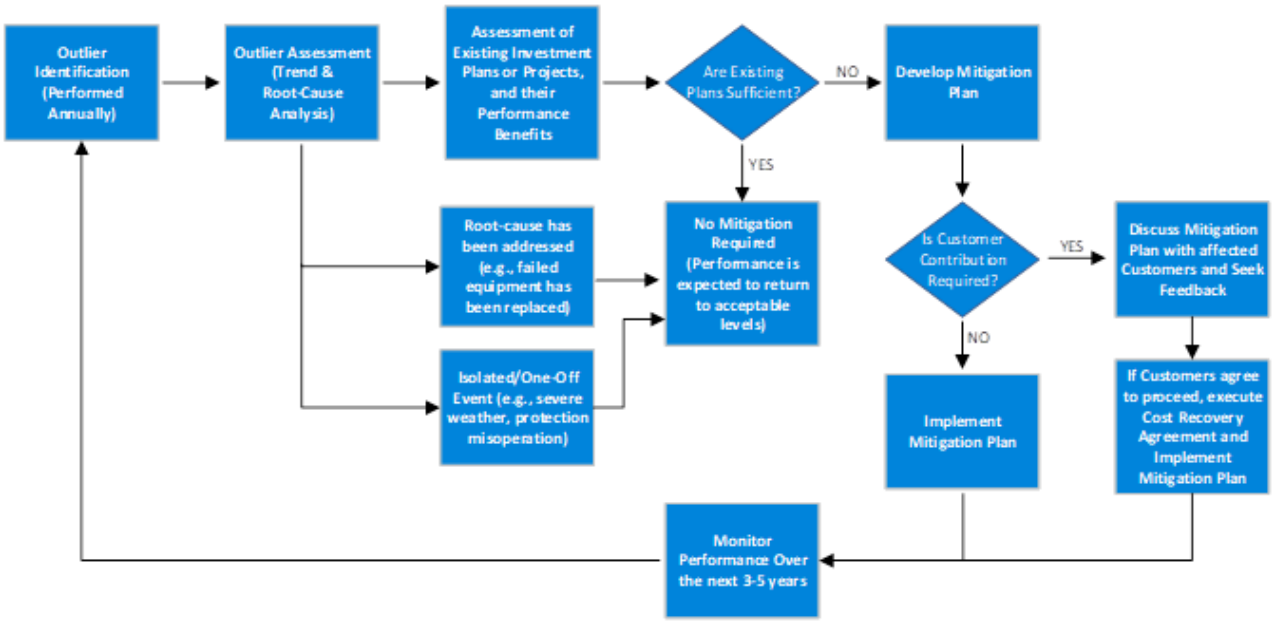

Figure 1: Outlier Assessment and Mitigation Process

1. Hydro One identifies DP performance "outliers" on an annual basis for both Group and Individual standards. The DP performance data lags one year because performance data for a subject year is made available the following year.

2. Hydro One will then undertake an assessment to determine the root cause of unsatisfactory performance associated with each performance outlier identified in (1).

3. Hydro One will develop mitigation options to address the root cause(s) of the outlier. Firstly, it is determined if the root cause has already been addressed (e.g. failed equipment has been replaced) or if it is related to an isolated event (e.g. severe weather, protection misoperation, etc.). If so, then no further mitigation is required, and performance is expected to return to acceptable levels. If not, then Hydro One will review existing investment plans and projects to evaluate their performance benefits for each outlier and determine if they are sufficient to address the performance outlier. If they are deemed to be sufficient, then no further mitigation is required, and performance is expected to return to acceptable levels. If not, then Hydro One will

develop an economically feasible mitigation plan to address performance outliers, including, (i) the work to improve and sustain the inherent reliability performance of the existing assets to what was designed originally; and (ii) for Group Performance Outliers, the additional capital improvements required to improve the performance of an outlier to within standard or beyond what was designed originally. Hydro One will discuss the proposed solutions with affected customers in cases where a capital contribution may be required. The overall outlier assessment and mitigation plan development process (steps 2 and 3) takes about 6-8 months to complete for all outliers.

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5. Hydro One and customers obtain the necessary approvals, including a signed Cost Recovery Agreement, to proceed with the mitigation plan to address performance outliers.

6. Hydro One will integrate the solutions into its work programs and implement them according to a mutually agreed schedule.

7. Hydro One develops an Annual Outlier Delivery Point report that summarizes the assessment results of all identified outliers.

When Hydro One completes work to improve DP performance, it continues to monitor the DP as part of its Annual Outlier Assessment and Mitigation Process. If future performance suggests that the standard has not been met, then Hydro One will review the work that has taken place as well as any other causes and events that may have occurred causing the DP to remain below the standard and will identify corrective action as needed. Hydro One reviews and identifies CDPP annually, regardless of the investment history.

Hydro One also issues an annual “Large Customer Reliability Report” to our LDCs, Industrial, and Generation customers connected to the Transmission system (115kV and above) as well as embedded LDCs (44kV, 27.6kV, 13.8kV). In addition, customer briefing reports regarding specific reliability or power quality disturbances are provided to customers, which summarize the investigation and analysis results as well as follow up actions to be undertaken.

Beyond the Annual Outlier Assessment and Mitigation Process, customers can also contact their Hydro One Account Executive representative to discuss any concerns they may have about CDPP and request further analysis. This can be initiated by a customer(s) at any time (i.e., it does not have to coincide with the Annual Outlier Assessment and Mitigation Process shown in Figure 1) to allow for timely assessment and mitigation of specific CDPP concerns.

3.0 POWER QUALITY

Power Quality is another important characteristic of electricity apart from reliability. The following sections discuss Power Quality (PQ) and causes for PQ issues, recommendations to mitigate PQ issues, and provide information on PQ requirements in Ontario, nationally, and internationally. It also discusses Hydro One's role in managing PQ.

3.1 What is Power Quality?

The term Power Quality (PQ) refers to characteristics of electricity at a given point on an electrical system, evaluated against a set of reference technical parameters. These characteristics are classified in terms of traits that reflect a departure in the quality of supply from its desired form, such as voltage sag, voltage swells, voltage unbalance, transient disturbances, harmonic distortions, flicker, etc.

In technical terms, voltage and current waveforms should ideally remain perfectly sinusoidal at a specified frequency everywhere in the network. For three-phase systems, it is also required that the magnitudes of three-phase quantities and the angular displacement between consecutive phases remain equal. Deviation from these norms is a departure from the ideal and termed a distortion. Under normal operating conditions, distortions will occur, even in the absence of any faults or disturbances related to switching operations. Some of the reasons for this are listed below:

- Loads continually changing in ways that cause current loading levels, and therefore also voltage levels, to differ among the three phases.
- Harmonic currents introduced by nonlinear loads such as single and three-phase rectifiers (as found in industrial loads), switch-mode supplies (as found in virtually all modern appliances including lighting controls), arc furnaces, static var compensators as well as conventional iron core devices such as motors and transformers.

- Inter-harmonic currents are produced by AC and DC arc furnaces and AC motor drives.
- Unbalance created by single-phase loads connected to three-phase systems.
- Flicker produced by fluctuating loads.

More severe distortions to the voltage waveform can also be introduced by unpredictable events causing faults on the system such as a lightning strike, animal or vegetation contact, vehicle accidents, and equipment failures. All such disturbances aggregate in a complicated manner over a widely distributed and topologically diverse electric supply transmission and distribution network. Differences in the density of loads and their variable contributions combine with differences in network impedances (i.e., short circuit levels) to yield varying distortion levels throughout the network.

It is also important to note that customer's equipment tolerance of power quality disturbances is controllable by design and therefore a customer's selection of equipment is a critical factor in sensitivity of their plants and processes to power quality disturbances. In some instances, customer-installed equipment can also be a source of power quality disturbances, affecting the customer's own equipment as well as other customers supplied from the same utility infrastructure. In recent years, some customer equipment in industrial processes have become extremely sensitive to *voltage sags (and swells)* due to their increased reliance on electronics and microprocessor controls.[6] While no consensus has emerged among industry standards organizations on assigning meaningful limits to such disturbances for power utilities, there is widespread recognition among industrial organizations and international standards organizations that a practical solution for managing disruptions due to voltage sags is to properly design industrial electrical equipment to be tolerant of the level and duration of sags commonly found to occur in electricity supply transmission and distribution systems. Given the diverse range of equipment sensitivities and the associated economic impacts for the processes involved, it is most effective and economical to implement corrective measures close to the customer's equipment that is experiencing disruptions. The International Electrotechnical Commission ("IEC") and the Institute of Electrical and Electronics Engineers ("IEEE") have developed standards defining the test setup, test methods, and measurement requirements for characterizing equipment tolerance of PQ disturbances (e.g., CAN/CSA-IEC 61000-4-30, IEC 61000-4-11, IEC 61000-4-34, IEEE 1668, etc.). In addition, industrial sectors, such as semiconductor industry have established performance requirements of equipment to specify equipment that is more sag-tolerant, based on the testing protocols and certifications in IEC and IEEE standards (e.g., SEMI F47, ITIC).

[6] Customers can experience both voltage sags and swells. Sag is a temporary reduction in the rms voltage below a threshold, whereas swell is a short-term increase in voltage above a certain threshold. This document refers to "voltage sag" because it is the common customer concern.

The IEC has also developed consumer equipment standards for vendors to reduce harmonic current emissions into electricity supply systems, which is mandatory in most parts of the world. Examples of these standards include:

- IEC 61000-3-2 Limits for harmonic current emissions (equipment input current less than or equal to 16A/phase)
- IEC 61000-3-12 Limits for harmonic current emissions produced by equipment connected to public low voltage system with input current>16A and less than or equal to 75A/phase)

Harmonics emissions can adversely impact both customer operations, and utility supply to other customers. The adoption of these standards in the European Union ("EU") system has shown a significant reduction in harmonics in electricity supply systems over the last few years. In light of the increase in non-linear load and a race to net-zero, it is essential that harmonic emissions are minimized at the source to manage power quality for all customers. Hence, it is strongly recommended that vendors and consumers utilize equipment designed as per the above standards.

Customers should also contact Hydro One for advice before upgrading major systems, adding substantial equipment, or changing hours of operation. This will ensure customers are being provided with information that can help design their facilities to work reliably and efficiently, thereby minimizing the risk of PQ disturbances and avoiding any adverse impact. Joint co-operation between various stakeholders and Hydro One teams is important to address PQ incidents.

As of the date of this document, requirements in Ontario related to PQ can be found in the OEB's TSC, including Appendix 2: "Transmission System Connection Point Performance Standards".

3.2 Power Quality versus Reliability

It is important to distinguish between the terms "Reliability" and "Power Quality" which are often used interchangeably by customers. Power interruptions, categorized into sustained interruptions (lasting more than 1 minute) and momentary interruptions (lasting 1 minute or less) are considered reliability issues. Reliability refers to a loss of voltage at the DP (i.e., power is off). Some momentary interruptions, lasting only seconds, may be perceived as power quality issues, yet they are frequently initiated by the distributor's protective equipment operations, aimed at avoiding more prolonged interruptions. Voltage sag, for example, is associated with PQ because it refers to the Root Mean Square ("RMS") voltage level dropping below 90% of the nominal value (i.e., power is on, but it does not

conform to normal characteristics of supply, and this in turn may prove disruptive to some sensitive electronic equipment).

3.3 Power Quality Inquiry Response Process

Hydro One has processes in place to manage and address customer PQ issues. Our Power Quality Inquiry Response Process has been developed in order to respond to customer inquiries pertaining to power quality in a timely and consistent manner. There is a six-step process, as listed below:

Step 1: Gather PQ Inquiry Info
This step is aimed at gathering information for investigating customers' PQ inquiries in a timely, consistent and cost-effective manner. To facilitate this step, customers should complete and submit an online Power Quality Incident Form to report a PQ incident.

Step 2: Quick Assessment
A PQ inquiry received will be acknowledged within five working days. If the issue or inquiry is straightforward, a response will be provided to the customer within 10 working days. Otherwise, if the inquiry is complex, a detailed assessment will be undertaken in collaboration with the customer to assess and develop appropriate mitigation on the utility system and/or customer facility.

Step 3: Detailed Assessment & Solution Development
Hydro One will establish scope and schedule for a detailed assessment of Hydro One's network performance and/or customer facility operation. Based on this detailed assessment, the root cause of the PQ issue will be identified, and possible remedial option(s) will be developed working in collaboration with the customer.

Step 4: Finalize Solution with Customer
Based on the assessment, mitigation may be required on the transmission or distribution system and/or the customer facility. If the customer(s) is required to make a capital contribution for any mitigation on the transmission or distribution system and/or implement mitigation within their own facility, implementation of the solution(s) will proceed with consent and approval of both parties. If no customer contribution is required, Hydro One will plan and schedule work according to its investment planning process.

Step 5: Information Captured and Retained
Customers may opt to take no action or defer implementation of a solution for a variety of reasons, including cost or impact on operations. Hydro One retains information on the PQ investigation for future use if required.

Step 6: Implement Solution and Confirm Effectiveness
This step ensures that the schedule in implementing the recommended solution is followed and implementation status is tracked. After the implementation of the plan, the customer is contacted to verify its effectiveness.

More information on this process can be found on Hydro One's webpage: Power Quality Inquiry Response Process.

3.4 Power Quality Activities

Hydro One is undertaking various actions with respect to managing PQ disturbances, including (but not limited to) the following:

- Standing policy of installing PQ monitors, as part of station sustainment and development initiatives, in order to gain improved visibility of PQ performance at key points in the delivery network, including provision for doing the same at customer DPs.

- A standing offer to large industrial and commercial customers to participate in a co-funded "PQ audit", conducted by an external service provider, the Electric Power Research Institute ("EPRI"). This involves a detailed review of customer plant equipment and processes by PQ specialists, in order to identify potential vulnerabilities to common PQ disturbances, such as voltage sags. It also provides a range of options for reducing such vulnerabilities including a breakdown of their associated implementation cost.

- An ongoing process of updating design and operating practices, where opportunities arise, aimed at reducing PQ disturbances. An example includes recent adoption of a particular circuit switcher as our standard device for energizing capacitor banks (instead of conventional circuit breakers) in order to moderate switching transients that often disrupt industrial processes. Other examples include our various initiatives for improving vegetation management programs and ongoing deployment of improved animal contact prevention devices at stations.

More information on PQ can be found on Hydro One's webpage: Power Quality

3.5 Additional References to Power Quality Standards

For additional reference purposes, the detailed list below includes references to national and international standards as well as Codes in Ontario related to Power Quality:

- CAN/CSA-C61000-2-2: Environment - Compatibility levels for low-frequency conducted disturbances and signaling in public low-voltage power supply systems

- CAN/CSA-C61000-3-2: Limits - Limits for harmonic current emissions (equipment input current =16 A per phase)

- CAN/CSA-C61000-3-3: Electromagnetic compatibility (EMC) - Part 3-3: Limits - Limitation of voltage changes, voltage fluctuations, and flicker in public low-voltage supply systems, for equipment with rated current <=16 A per phase and not subject to conditional connection

- CAN/CSA-IEC/TS 61000-3-5: Electromagnetic compatibility (EMC) - Part 3-5: Limits - Limitation of voltage fluctuations and flicker in low-voltage power supply systems for equipment with rated current greater than 75 A

- CAN/CSA -C61000-3-6: Limits - Assessment of Emission levels for the connection of distorting installations to MV, HV, and EHV power systems

- CAN/CSA -C61000-3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems

- CSA C61000-3-14: Electromagnetic compatibility (EMC) - Part 3-14: Assessment of emission limits for harmonics, interharmonics, voltage fluctuations and unbalance for the connection of disturbing installations to LV power systems

- CAN/CSA-IEC 61000-4-30 - Testing and measurement techniques - Power quality measurement methods

- CSA C235:19 - Preferred voltage levels for AC systems up to 50 000 V

- IEC 61000-3-12: Limits for harmonic current emissions produced by equipment connected to public low voltage system with input current>16A and less than or

equal to 75A/phase)

- IEC 61000-4-11: Testing and measurement techniques - Voltage dips, short interruptions and voltage variations immunity tests for equipment with input current up to 16 A per phase

- IEC 61000-4-34: Testing and measurement techniques - Voltage dips, short interruptions and voltage variations immunity tests for equipment with input current more than 16 A per phase

- IEEE Std 1668: IEEE Recommended Practice for Voltage Sag and Short Interruption Ride-Through Testing for End-Use Electrical Equipment Rated Less than 1000 V

- SEMI F47-0706: Specification for Semiconductor Processing Equipment Voltage Sag Immunity

- SEMI F-42-0699: Test Method for Voltage Sag Susceptibility of Semiconductor Processing Equipment

- Information Technology Industry Council (ITIC) Curve

- Ontario Energy Board (OEB), Distribution System Code

- Ontario Energy Board (OEB), Transmission System Code

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Pasquale.Catalano@HydroOne.com

BY EMAIL AND RESS

February 27, 2026

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2021-0307 - Changes to Improve the Transmission Framework for Reliability and Power Quality - Hydro One Sault Ste. Marie Limited Partnership Transmitter Standards Document

In accordance with the Ontario Energy Board's (OEB) expectations outlined in the OEB's November 27, 2025 letter in this proceeding (the November 27 Letter), Hydro One Sault Ste. Marie Limited Partnership (HOSSM) is providing the OEB a revised Transmitter Standards Document that is consistent with the changes discussed in the November 27 Letter.

An electronic copy of these performance standards has been filed through the OEB's Regulatory Electronic Submission System.

Sincerely,

Pasquale Catalano

Hydro One Networks Inc.

Customer Delivery Point Performance Standards (CDPPS) and Power Quality

Prepared by: Hydro One Sault Ste. Marie

Last Revised: February 27, 2026

(Supersedes: Great Lakes Power Limited – Transmission Customer Delivery Point Performance Standards, December 2007)

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1.0 INTRODUCTION

The Transmission System Code (TSC) requires transmitters to develop Customer Delivery Point Performance ("CDPP")[1] Standards at the customer delivery point level, consistent with system wide standards, that:

- reflect typical transmission system configurations that consider the historical development of the transmission system at the customer delivery point level;
- reflect historical performance at the customer delivery point level;
- establish acceptable bands of performance at the customer delivery point level for the transmission system configurations, geographic area, circuit length, etc.;
- establish a process to evaluate delivery point performance and triggers that would initiate technical evaluation by the transmitter and financial evaluation, where required, in consultation with customers, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;
- establish the steps to be taken based on the results of any evaluation that has been triggered, as well as the circumstances in which such steps need not be taken;
- establish any circumstances in which the performance standards will not apply.

In 2021, the OEB initiated a Reliability and Power Quality Review (RPQR) consultation with stakeholders. In 2023, the OEB RPQR formed a Subgroup for Transmission ("the Subgroup"). One of the objectives of this group was to discuss potential changes to the current reliability framework for transmitters. The Subgroup recommended changes to the existing CDPP standards to the OEB, mainly to the Group Outlier standard (described in section 2.1 of this document), and adding a new section to this document related to Power Quality (described in section 3.0 of this document). The OEB approved these changes on November 27, 2025 (EB-2021-0307). To address the OEB's direction, HOSSM confirms it is adopting Hydro One's revised CDPP Standards, which was submitted to OEB for approval on February 27, 2026. HOSSM, as an applicable transmitter, is also filing this CDPP Standards and Power Quality document for the OEB's approval.

The CDPP Standards apply to all transmission load customers (including customers that have signed a Connection Cost Recovery Agreement prior to May 1, 2002, market opening).

[1] A Delivery Point is defined as a point of connection between a transmitter's transmission facilities and a customer's facilities.

2.0 DELIVERY POINT RELIABILITY STANDARDS

The approved CDPP Standards consist of two components: (1) Group CDPP Standards that relate the reliability of supply to the supply configuration (single circuit versus multi circuit) and supply circuit length for single circuits and (2) Individual CDPP Standards that maintain a customer's individual historical delivery point performance. Triggers for each component are used to identify performance "outliers" to initiate technical and financial evaluations to determine the root cause of unsatisfactory performance and if remedial action is required to address the root cause. The CDPP Standards and triggers for each component are summarized below.

2.1 Group CDPP Standards: Performance Standards Based on Supply Configuration and Circuit Length

For this component, the CDPP Standards and the associated triggers are based on the predominant supply configuration (single circuit versus multi circuit) and circuit length for single supply circuits since delivery point ("DP") performance is strongly correlated to these two factors. For single circuits, the CDPP Standards vary with the length of the supply circuit in ranges of 0 to 40 km, greater than 40 up to 90 km, greater than 90 up to 150 km, and greater than 150 km, as shown in Table 1 below.

Table 1
Customer Delivery Point Performance Group Standards Based on Supply Configuration and Circuit Length

	Customer Delivery Point Performance Group Standards				
	Multi-Circuit Supplied DPs	Single Circuit Supplied DPs			
Supply Circuit Length (L in km)	N/A	L≤40 km	40<L≤90 km	90<L≤150 km	L>150 km
DP Frequency of Interruptions Threshold (# interruptions/DP/yr)	1	2	5	7	9
DP Interruption Duration Threshold (interruption minutes/DP/yr)	58	200	300	380	854

These CDPP Standards are based on historical 2013-2022 performance data as measured by the average frequency and duration of all forced (momentary and sustained) interruptions[2] plus one standard deviation, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical performance. To avoid this, such events are excluded from the calculation[3].

For any new DP that is added to the system, the DP performance is assessed based on the corresponding band within the Group CDPP Standards that applies (i.e., corresponding threshold for multi or single circuit and appropriate length if single circuit). For new customers connecting to an existing DP, the existing Group CDPP Standards will apply immediately.

2.1.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Group CDPP Standards

The minimum Group CDPP standards of performance (see Table 1), for both frequency and duration of interruptions, are to be used as triggers by HOSSM in identifying Group Outliers. The trigger occurs when the frequency and/or duration of interruptions at a DP exceeds its corresponding Group threshold in two consecutive years (and therefore is identified as a Group Outlier) or when a DP customer requests an analysis. When a Group outlier is identified, it is considered a candidate for remedial action. In such cases, HOSSM will initiate a technical evaluation to determine the root cause of the unsatisfactory performance and any remedial actions to address it. HOSSM will also initiate a financial evaluation for remedial actions, where required, in consultation with affected customers.

2.2 Individual CDPP Standards: Performance Standards to Maintain Historical Delivery Point Performance

For this component, the CDPP Standards are intended to maintain the historical reliability performance levels at each customer DP. This is done by identifying customer DPs with deteriorating trends in reliability performance, irrespective of whether they are satisfactory performers under the Group CDPP Standards (Section 2.1 above). To identify customer

[2] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any forced interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more HOSSM's components causing load loss. Interruptions caused by HOSSM's customers are recorded but not charged against HOSSM's reliability performance for the customer initiating the interruption but are charged against HOSSM's reliability performance for other interrupted customers.

[3] Such as the 2013 GTA flood and 2018 Ottawa Area tornado.

DPs with deteriorating trends in reliability performance, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is established for each DP based on that DP's historical 2013-2022 average performance, plus one standard deviation (the "Historical Baseline"). The Historical Baseline excludes outages resulting from extraordinary events[4] that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, skew the historical performance. To avoid this, such events are excluded from the calculation.

For any new DP that is added to the system, the DP performance is assessed based on the Group CDPP Standards for the first four calendar years after being placed in-service. Temporary Individual baselines are then created after the DP has been in-service for 5 calendar years and are finalized when it has been in-service for 10 years consistent with the method for the Historical Baseline. For new customers connecting to an existing DP, the existing Individual Historical Baseline for the DP will apply immediately.

Also, for DPs that have not experienced any interruptions, or zero interruption duration occurred during the 10-year period used for establishing a DP's Individual Historical Baseline, the corresponding frequency and/or duration baselines for the DP would be zero. In such cases, these DPs would be an Individual outlier if it experiences any number of interruptions for two consecutive years.

2.2.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Individual CDPP Standards

The minimum Individual CDPP standards of performance, for both frequency and duration, are to be used as triggers by HOSSM in identifying Individual Outliers. The trigger occurs when the frequency and/or duration of interruptions exceeds the Historical Baseline in two consecutive years (and therefore is identified as an Individual Outlier). When an Individual outlier is identified, it is considered a candidate for remedial action. In such cases, HOSSM will initiate a technical evaluation to determine the root cause of the unsatisfactory performance and any remedial actions required to restore reliability to the Historical Baseline of the DP's performance. HOSSM will also initiate a financial evaluation for remedial actions, where required, in consultation with affected customers.

[4] Such as the 2013 GTA flood and 2018 Ottawa Area tornado

2.3 Remedial Costs to Address Group and Individual Performance Outliers

For Group and Individual Performance Outliers, HOSSM will develop and undertake a feasible and cost-effective mitigation plan that is intended to improve the reliability performance of the existing assets as per its original design. For example, performance of DPs supplied by a single circuit will not be mitigated by planning a second circuit supply as that is highly cost prohibitive and a customer contribution would be required, consistent with the TSC. However, HOSSM continuously makes investments to maintain the transmission system and address reliability performance such as replacing aging infrastructure. These expenditures are made on an ongoing basis irrespective of whether a DP is an outlier or not which helps maintain or improve supply reliability.

Investments are reviewed as part of HOSSM's Outlier Assessment and Mitigation Process (refer to section 2.4). Many planned investments directly address the root cause of unsatisfactory DP performance and further action and incremental investment is typically not required. No customer contribution is required for these planned capital expenditures by HOSSM. For Individual Performance Outliers where investments are required beyond HOSSM's planned investments, HOSSM will develop an economically feasible mitigation plan to improve DP performance to its original design. HOSSM will undertake the costs associated with this remedial work but will not include capital reliability improvements that require significant change to the original supply configuration to improve DP performance. In some cases, mitigation measures are incremental to the original design because the DP supply characteristics have significantly changed over the years (e.g., new customer connections supplied by the DP). In these situations, a customer contribution may be required.

For Group Performance Outliers, HOSSM's level of incremental investment for improving the performance of an outlier beyond what was designed originally will be limited to the present value of three years' worth of combined transformation and transmission line connection revenue[5] associated with the DP. Any funding shortfalls for improving DP reliability performance will be made up by affected DP customers. In cases where specific transmission facilities are serving two or more customers in common with outlier performance, HOSSM will approach all affected customers to determine their willingness to contribute jointly to the reliability improvements.

[5] In the special case where a delivery point pays only network tariffs, transmission line connection tariffs are to be used as a proxy in the revenue calculation.

Cost responsibility for any investment is to be consistent with the TSC. Where a customer contribution is required as part of the mitigation plan to improve DP performance, HOSSM will consult with the customer on the solution and execute Cost Recovery Agreements as needed. In addition, affected DP customers are responsible for all the costs associated with any new or modified facilities they own to improve their reliability performance.

2.4 Outlier Assessment and Mitigation Process

The process and associated timelines that will be followed to address performance outliers – both for Group and Individual outliers – and determine the preferred course of action is provided below.

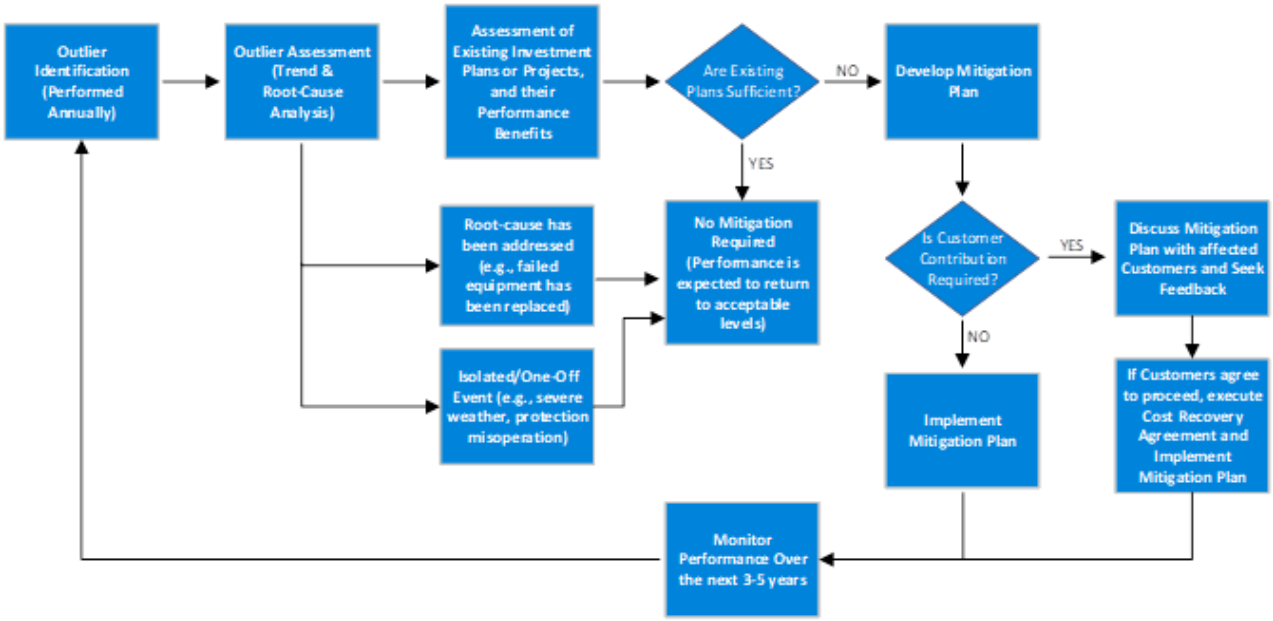

Figure 1: Outlier Assessment and Mitigation Process

1. HOSSM identifies DP performance "outliers" on an annual basis for both Group and Individual standards. The DP performance data lags one year because performance data for a subject year is made available the following year.

2. HOSSM will then undertake an assessment to determine the root cause of unsatisfactory performance associated with each performance outlier identified in (1).

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5. HOSSM and customers obtain the necessary approvals, including a signed Cost Recovery Agreement, to proceed with the mitigation plan to address performance outliers.

6. HOSSM will integrate the solutions into its work programs and implement them according to a mutually agreed schedule.

7. Hydro One develops an Annual Outlier Delivery Point report that summarizes the assessment results of all identified outliers. This report considers HOSSM DPs as well.

When HOSSM completes work to improve DP performance, it continues to monitor the DP as part of its Annual Outlier Assessment and Mitigation Process. If future performance suggests that the standard has not been met, then HOSSM will review the work that has taken place as well as any other causes and events that may have occurred causing the DP to remain below the standard and will identify corrective action as needed. HOSSM reviews and identifies CDPP annually, regardless of the investment history.

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reports regarding specific reliability or power quality disturbances are provided to customers, which summarize the investigation and analysis results as well as follow up actions to be undertaken. Customer briefing reports are also developed for HOSSM customers as needed.

Beyond the Annual Outlier Assessment and Mitigation Process, customers can also contact their Hydro One Account Executive representative to discuss any concerns they may have about CDPP (including HOSSM DPs) and request further analysis. This can be initiated by a customer(s) at any time (i.e., it does not have to coincide with the Annual Outlier Assessment and Mitigation Process shown in Figure 1) to allow for timely assessment and mitigation of specific CDPP concerns.

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3.1 What is Power Quality?

The term Power Quality (PQ) refers to characteristics of electricity at a given point on an electrical system, evaluated against a set of reference technical parameters. These characteristics are classified in terms of traits that reflect a departure in the quality of supply from its desired form, such as voltage sag, voltage swells, voltage unbalance, transient disturbances, harmonic distortions, flicker, etc.

In technical terms, voltage and current waveforms should ideally remain perfectly sinusoidal at a specified frequency everywhere in the network. For three-phase systems, it is also required that the magnitudes of three-phase quantities and the angular displacement between consecutive phases remain equal. Deviation from these norms is a departure from the ideal and termed a distortion. Under normal operating conditions, distortions will occur, even in the absence of any faults or disturbances related to switching operations. Some of the reasons for this are listed below:

- Loads continually changing in ways that cause current loading levels, and therefore also voltage levels, to differ among the three phases.
- Harmonic currents introduced by nonlinear loads such as single and three-phase rectifiers (as found in industrial loads), switch-mode supplies (as found in virtually all modern appliances including lighting controls), arc furnaces, static var compensators as well as conventional iron core devices such as motors and transformers.
- Inter-harmonic currents are produced by AC and DC arc furnaces and AC motor drives.
- Unbalance created by single-phase loads connected to three-phase systems.
- Flicker produced by fluctuating loads.

More severe distortions to the voltage waveform can also be introduced by unpredictable events causing faults on the system such as a lightning strike, animal or vegetation contact, vehicle accidents, and equipment failures. All such disturbances aggregate in a complicated manner over a widely distributed and topologically diverse electric supply transmission and distribution network. Differences in the density of loads and their variable contributions combine with differences in network impedances (i.e., short circuit levels) to yield varying distortion levels throughout the network.

It is also important to note that customer's equipment tolerance of power quality disturbances is controllable by design and therefore a customer's selection of equipment is a critical factor in sensitivity of their plants and processes to power quality disturbances. In some instances, customer-installed equipment can also be a source of power quality disturbances, affecting the customer's own equipment as well as other customers supplied from the same utility infrastructure. In recent years, some customer equipment in industrial processes have become extremely sensitive to *voltage sags (and swells)* due to their increased reliance on electronics and microprocessor controls.[6] While no consensus has emerged among industry standards organizations on assigning meaningful limits to such disturbances for power utilities, there is widespread recognition among industrial organizations and international standards organizations that a practical solution for managing disruptions due to voltage sags is to properly design industrial electrical equipment to be tolerant of the level and duration of sags commonly found to occur in electricity supply transmission and distribution systems. Given the diverse range of equipment sensitivities and the associated economic impacts for the processes involved, it is most effective and economical to implement corrective measures close to the customer's equipment that is experiencing disruptions. The International

[6] Customers can experience both voltage sags and swells. Sag is a temporary reduction in the rms voltage below a threshold, whereas swell is a short-term increase in voltage above a certain threshold. This document refers to "voltage sag" because it is the common customer concern.

Electrotechnical Commission ("IEC") and the Institute of Electrical and Electronics Engineers ("IEEE") have developed standards defining the test setup, test methods, and measurement requirements for characterizing equipment tolerance of PQ disturbances (e.g., CAN/CSA-IEC 61000-4-30, IEC 61000-4-11, IEC 61000-4-34, IEEE 1668, etc.). In addition, industrial sectors, such as semiconductor industry have established performance requirements of equipment to specify equipment that is more sag-tolerant, based on the testing protocols and certifications in IEC and IEEE standards (e.g., SEMI F47, ITIC).

The IEC has also developed consumer equipment standards for vendors to reduce harmonic current emissions into electricity supply systems, which is mandatory in most parts of the world. Examples of these standards include:

- IEC 61000-3-2 Limits for harmonic current emissions (equipment input current less than or equal to 16A/phase)
- IEC 61000-3-12 Limits for harmonic current emissions produced by equipment connected to public low voltage system with input current>16A and less than or equal to 75A/phase)

Harmonics emissions can adversely impact both customer operations, and utility supply to other customers. The adoption of these standards in the European Union ("EU") system has shown a significant reduction in harmonics in electricity supply systems over the last few years. In light of the increase in non-linear load and a race to net-zero, it is essential that harmonic emissions are minimized at the source to manage power quality for all customers. Hence, it is strongly recommended that vendors and consumers utilize equipment designed as per the above standards.

Customers should also contact Hydro One for advice before upgrading major systems, adding substantial equipment, or changing hours of operation. This will ensure customers are being provided with information that can help design their facilities to work reliably and efficiently, thereby minimizing the risk of PQ disturbances and avoiding any adverse impact. Joint co-operation between various stakeholders and Hydro One teams is important to address PQ incidents.

As of the date of this document, requirements in Ontario related to PQ can be found in the OEB's TSC, including Appendix 2: "Transmission System Connection Point Performance Standards".

3.2 Power Quality versus Reliability

It is important to distinguish between the terms “Reliability” and “Power Quality” which are often used interchangeably by customers. Power interruptions, categorized into sustained interruptions (lasting more than 1 minute) and momentary interruptions (lasting 1 minute or less) are considered reliability issues. Reliability refers to a loss of voltage at the DP (i.e., power is off). Some momentary interruptions, lasting only seconds, may be perceived as power quality issues, yet they are frequently initiated by the distributor's protective equipment operations, aimed at avoiding more prolonged interruptions. Voltage sag, for example, is associated with PQ because it refers to the Root Mean Square (“RMS”) voltage level dropping below 90% of the nominal value (i.e., power is on, but it does not conform to normal characteristics of supply, and this in turn may prove disruptive to some sensitive electronic equipment).

3.3 Power Quality Inquiry Response Process

Hydro One has processes in place to manage and address customer PQ issues. Our Power Quality Inquiry Response Process has been developed in order to respond to customer inquiries pertaining to power quality in a timely and consistent manner. There is a six-step process, as listed below:

Step 1: Gather PQ Inquiry Info
This step is aimed at gathering information for investigating customers’ PQ inquiries in a timely, consistent and cost-effective manner. To facilitate this step, customers should complete and submit an online Power Quality Incident Form to report a PQ incident.

Step 2: Quick Assessment
A PQ inquiry received will be acknowledged within five working days. If the issue or inquiry is straightforward, a response will be provided to the customer within 10 working days. Otherwise, if the inquiry is complex, a detailed assessment will be undertaken in collaboration with the customer to assess and develop appropriate mitigation on the utility system and/or customer facility.

Step 3: Detailed Assessment & Solution Development
Hydro One will establish scope and schedule for a detailed assessment of Hydro One’s network performance and/or customer facility operation. Based on this detailed assessment, the root cause of the PQ issue will be identified, and possible remedial option(s) will be developed working in collaboration with the customer.

Step 4: Finalize Solution with Customer
Based on the assessment, mitigation may be required on the transmission or distribution system and/or the customer facility. If the customer(s) is required to make a capital contribution for any mitigation on the transmission or distribution system and/or implement mitigation within their own facility, implementation of the solution(s) will proceed with consent and approval of both parties. If no customer contribution is required, Hydro One will plan and schedule work according to its investment planning process.

Step 5: Information Captured and Retained
Customers may opt to take no action or defer implementation of a solution for a variety of reasons, including cost or impact on operations. Hydro One retains information on the PQ investigation for future use if required.

Step 6: Implement Solution and Confirm Effectiveness
This step ensures that the schedule in implementing the recommended solution is followed and implementation status is tracked. After the implementation of the plan, the customer is contacted to verify its effectiveness.

More information on this process can be found on Hydro One's webpage: Power Quality Inquiry Response Process.

3.4 Power Quality Activities

Hydro One is undertaking various actions with respect to managing PQ disturbances, including (but not limited to) the following:

- Standing policy of installing PQ monitors, as part of station sustainment and development initiatives, in order to gain improved visibility of PQ performance at key points in the delivery network, including provision for doing the same at customer DPs.

- A standing offer to large industrial and commercial customers to participate in a co-funded "PQ audit," conducted by an external service provider, the Electric Power Research Institute ("EPRI"). This involves a detailed review of customer plant equipment and processes by PQ specialists, in order to identify potential vulnerabilities to common PQ disturbances, such as voltage sags. It also provides a range of options for reducing such vulnerabilities including a breakdown of their associated implementation cost.

- An ongoing process of updating design and operating practices, where opportunities arise, aimed at reducing PQ disturbances. An example includes recent adoption of a particular circuit switcher as our standard device for energizing capacitor banks (instead of conventional circuit breakers) in order to moderate switching transients that often disrupt industrial processes. Other examples include our various initiatives for improving vegetation management programs and ongoing deployment of improved animal contact prevention devices at stations.

More information on PQ can be found on Hydro One's webpage: Power Quality

3.5 Additional References to Power Quality Standards

For additional reference purposes, the detailed list below includes references to national and international standards as well as Codes in Ontario related to Power Quality:

- CAN/CSA-C61000-2-2: Environment - Compatibility levels for low-frequency conducted disturbances and signaling in public low-voltage power supply systems

- CAN/CSA-C61000-3-2: Limits - Limits for harmonic current emissions (equipment input current =16 A per phase)

- CAN/CSA-C61000-3-3: Electromagnetic compatibility (EMC) - Part 3-3: Limits - Limitation of voltage changes, voltage fluctuations, and flicker in public low-voltage supply systems, for equipment with rated current <=16 A per phase and not subject to conditional connection

- CAN/CSA-IEC/TS 61000-3-5: Electromagnetic compatibility (EMC) - Part 3-5: Limits - Limitation of voltage fluctuations and flicker in low-voltage power supply systems for equipment with rated current greater than 75 A

- CAN/CSA -C61000-3-6: Limits - Assessment of Emission levels for the connection of distorting installations to MV, HV, and EHV power systems

- CAN/CSA -C61000-3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems

- CSA C61000-3-14: Electromagnetic compatibility (EMC) - Part 3-14: Assessment of emission limits for harmonics, interharmonics, voltage fluctuations and unbalance for the connection of disturbing installations to LV power systems

- CAN/CSA-IEC 61000-4-30 - Testing and measurement techniques - Power quality measurement methods

- CSA C235:19 - Preferred voltage levels for AC systems up to 50 000 V

- IEC 61000-3-12: Limits for harmonic current emissions produced by equipment connected to public low voltage system with input current>16A and less than or equal to 75A/phase)

- IEC 61000-4-11: Testing and measurement techniques - Voltage dips, short interruptions and voltage variations immunity tests for equipment with input current up to 16 A per phase

- IEC 61000-4-34: Testing and measurement techniques - Voltage dips, short interruptions and voltage variations immunity tests for equipment with input current more than 16 A per phase

- IEEE Std 1668: IEEE Recommended Practice for Voltage Sag and Short Interruption Ride-Through Testing for End-Use Electrical Equipment Rated Less than 1000 V

- SEMI F47-0706: Specification for Semiconductor Processing Equipment Voltage Sag Immunity

- SEMI F-42-0699: Test Method for Voltage Sag Susceptibility of Semiconductor Processing Equipment

- Information Technology Industry Council (ITIC) Curve

- Ontario Energy Board (OEB), Distribution System Code

- Ontario Energy Board (OEB), Transmission System Code

SECTION 2.5 – TSP – PERFORMANCE MEASUREMENT AND OUTCOMES

2.5.1 INTRODUCTION

Hydro One is committed to achieving the goals underpinning the TSP. To give effect to this commitment, Hydro One has aligned its planning, execution and reporting functions around performance outcomes that are consistent with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF) outcomes. The RRF outcomes relate to Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. Hydro One's performance outcomes are reflected in its Transmission Scorecard (see Figure 1 below), which assists Hydro One in monitoring and measuring performance relative to these outcomes. The Executive Leadership Team regularly reviews progress on the scorecard metrics as described in the Performance Reporting Governance Document found in SPF Section 1.5.

In EB-2016-0050, Hydro One received OEB approval to acquire Hydro One Sault Ste. Marie (HOSSM), formerly Great Lakes Power Transmission. HOSSM's scorecard and associated performance results and targets are discussed in TSP Section 2.10 Attachment 3.

2.5.2 TRANSMISSION SCORECARD (OEB FILING REQUIREMENTS 2.3.5)

Hydro One's Transmission Scorecard was accepted as part of the OEB-approved Settlement Proposal in EB-2021-0110. Except for the proposed revisions that follow below, Hydro One will continue to use the measures approved in the prior application and has presented the prior application's targets up to 2027 (the Bridge year).

Hydro One proposes the following additions and removals to the Transmission Scorecard. Supporting details for these proposals are provided below on a metric by metric basis:

- Expansion of the Transmission Capital Accomplishment Index (TCAI)
- Removed % On-time completion of Customer Impact Assessments on Renewable Generation
- New metric for Resource Enablement

- New metric to send an Email communication to municipalities prior to the start of Regional Planning (%)
- New metric for Regional Planning Responsiveness

The Transmission Scorecard is organized according to the OEB's performance outcomes (i.e. Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance), with Hydro One's measures assigned to the appropriate performance outcome. The Transmission Scorecard is presented in Figure 1 below.

Performance Outcomes	Performance Categories	Measures	Performance						Targets									
			2021	2022	2023	2024	2025	Trend	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Customer Focus	Service Quality	Customer Delivery Point Performance - Standard Outliers as Percent of Total Delivery Points	8.3%	9.3%	10.9%	13.6%	9.3%	▲	11.0%	10.8%	10.6%	10.4%	10.2%	10.1%	10.1%	10.1%	10.0%	10.0%
	Customer Satisfaction	Overall Customer Satisfaction in Customer Survey (% Satisfied)	92%	88%	88%	85%	79%	▼	88%	88%	88%	88%	88%	84%	85%	85%	86%	86%
		Satisfaction with Outage Planning Procedures (% Satisfied)	82%	78%	72%	88%	84%	▲	85%	85%	85%	85%	85%	81%	82%	82%	83%	83%
Operational Effectiveness	Safety	Recordable Rate (# Recordable Injuries/Illnesses per 200,000 hours worked)	0.7	0.6	0.6	0.6	0.7	▼	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8
	System Reliability	T-SAIFI-S (Average Number of Sustained Interruptions per Delivery Point)	0.49	0.64	0.54	0.52	0.46	▼	0.56	0.55	0.54	0.52	0.51	0.51	0.51	0.50	0.50	0.50
		T-SAIFI-M (Average Number of Momentary Interruptions per Delivery Point)	0.42	0.43	0.46	0.44	0.26	▼	0.43	0.42	0.41	0.41	0.40	0.40	0.40	0.40	0.39	0.39
		T-SAIDI (Average minutes of Interruptions per Delivery Point)	21.0	60.6	25.9	23.7	18.5	▼	32.6	31.9	31.3	30.7	30.1	30.0	29.9	29.7	29.6	29.5
		System Unavailability (% of time system equipment is unavailable)	0.67%	0.76%	0.52%	0.50%	0.63%	▼	0.62%	0.61%	0.60%	0.59%	0.58%	0.58%	0.58%	0.57%	0.57%	0.57%
		Unsupplied Energy (System Minutes)	7.1	13.3	6.4	8.2	5.7	▼	9.0	8.8	8.6	8.4	8.2	8.2	8.1	8.1	8.1	8.0
	Asset and Project Management	Transmission System Plan Implementation Progress	99%	101%	97%	95%	91%	▼	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
		Capital Expenditures as a % of OEB Approved Plan	112%	114%	97%	114%	109%	▼	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
		OM&A Program Accomplishment (Composite Index)	105%	96%	109%	102%	97%	▼	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
		Transmission Capital Accomplishment Index (TCAI - Expanded)	99%	80%	91%	95%	112%	▲	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value	8.3%	7.6%	8.6%	8.5%	7.6%	▼	7.9%	8.0%	7.0%	6.8%	6.5%	10.8%	-	-	-	-
		OM&A per Gross Fixed Asset Value	2.0%	2.2%	2.4%	2.0%	1.8%	▼	1.9%	1.8%	1.8%	1.8%	1.7%	2.1%	-	-	-	-
		Line Clearing Cost per Kilometer ($/km)	$2,211	$2,140	$2,210	$2,426	$2,896	▲	$2,784	$2,854	$2,925	$2,998	$3,073	$2,767	$2,822	$2,879	$2,935	$2,994
		Brush Control Cost per Hectare ($/Ha)	$1,807	$2,003	$1,916	$2,402	$2,678	▲	$1,628	$1,669	$1,711	$1,754	$1,798	$2,799	$2,855	$2,912	$2,970	$3,030
Public Policy Responsiveness	Connection of Generation	% On-time completion of Customer Impact Assessments on Renewable Generation	100%	100%	None Req	None Req	None Req	►	100%	100%	100%	100%	100%	Removed				
		Resource Enablement (Connections & MW Enabled)	New					N/A	New					Report				
	Municipal Engagement for Regional Infrastructure Planning	Email communication sent to municipalities with a request for electricity planning input prior to the start of Regional Planning	New					N/A	New					100%	100%	100%	100%	100%
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning Progress - Deliverables met	95%	100%	100%	100%	100%	►	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
		Long Term Energy Plan End-of-Life Right-Sizing Assessment Expectation	Met	Met	Met	Met	Met	►	Met	Met	Met	Met	Met	Met	Met	Met	Met	Met
		Regional Planning Responsiveness	0	1	0	2	0	▲	Report on actual number of accelerated planning regions									
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	0.27	0.23	0.21	0.21	0.25	▼	-	-	-	-	-	-	-	-	-	-
		Leverage: Total Debt to Equity Ratio	1.40	1.37	1.48	1.65	1.72	▲	-	-	-	-	-	-	-	-	-	-
		Profitability: Regulatory Return on Equity (Deemed in Rates)	8.52%	8.52%	9.36%	9.36%	9.36%	N/A	-	-	-	-	-	-	-	-	-	-
		Profitability: Regulatory Return on Equity (Achieved)	9.30%	9.92%	10.80 %	10.96 %	12.72 %	▲	-	-	-	-	-	-	-	-	-	-

Figure 1: Hydro One's OEB Transmission Scorecard and Targets

The following sections discuss each of the measures shown in Figure 1 above. Each measure is defined, followed by a discussion of its historical performance and the targets set for the 2028-2032 rate period.

2.5.3 CUSTOMER FOCUS MEASURES

2.5.3.1 SERVICE QUALITY

The service quality metric measures how many Hydro One delivery points are outliers in terms of performance using the standards set by the OEB.

2.5.3.1.1 CUSTOMER DELIVERY POINT PERFORMANCE - STANDARD OUTLIERS AS PERCENT OF TOTAL DELIVERY POINTS

Performance Category	Measures	Description
Service Quality	Customer Delivery Point Performance - Standard Outliers as Percent of Total Delivery Points	The percentage of customer Delivery Points (DPs) deemed as either group or individual outliers.

Customer Delivery Point Performance Standards (CDPPS) were established by the OEB to ensure acceptable transmission reliability experienced at transmission customer delivery points. The group outlier standard defines a delivery point as an outlier if its performance is over the thresholds based on its station load size. The individual outlier standard defines a delivery point as an outlier if its recent two-year's performance is worse than its historical performance. The percentage of outliers to total number of delivery points is measured annually.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

The percentage of outliers in 2025 decreased by 4.3% compared to 2024, mainly due to a fewer number of Equipment and Foreign caused interruptions. 2024 performance of 13.6 was mainly due to a Greater Toronto Area flooding event that impacted 9 Hydro One Transmission Stations. Hydro One's average performance over the past five years (2021-2025) was 10.3% slightly above the target.

Table 1 - CDPPS Outliers as Percentage of Total Delivery Points

	2021	2022	2023	2024	2025	Trend
Target	11.5%	11.3%	11.0%	10.8%	10.6%	
Actual	8.3%	9.3%	10.9%	13.6%	9.3%	▲

TARGETS

Over the 2028-2032 period, Hydro One aims to improve CDPPS Outlier to 10.0%. The target reflects an overall 2% (0.2) reduction to the CDPPS Outlier target from the 2027 target.

The OEB recently approved changes to the Transmitter Standards Document (CDPP standards) on November 27, 2025 in a letter to transmitters (EB-2021-0307). On March 1, 2026, as required by the OEB, Hydro One filed its revised CDPP Standards to reflect these changes and is awaiting OEB approval, as discussed in TSP Section 2.4. Once approved, Hydro One will update the proposed CDPP targets.

Table 2 - CDPP Outlier Targets

	2026	2027	2028	2029	2030	2031	2032
Target	10.4%	10.2%	10.1%	10.1%	10.1%	10.0%	10.0%

2.5.3.2 CUSTOMER SATISFACTION

The customer satisfaction measures below were selected to demonstrate the level of satisfaction that transmission customers express with Hydro One overall and with its outage planning procedures. These measures are measured and reported on a combined basis for Hydro One Transmission and HOSSM.

2.5.3.2.1 OVERALL CUSTOMER SATISFACTION IN CUSTOMER SURVEY (PERCENT SATISFIED)

Performance Category	Measures	Description
Customer Satisfaction	Overall Customer Satisfaction in customer survey (% Satisfied)	This measure reflects the overall satisfaction levels among customers within the three major transmission-connected (LTX) segments (Transmission End Users, Local Distribution Companies (LDC) and Transmission-Connected Generators).

Hydro One has been measuring overall customer satisfaction among the three major transmission-connected (LTX) segments (Transmission End Users, Local Distribution Companies (LDC) and Transmission-Connected Generators) in its annual customer satisfaction (CSAT) survey since 2012. This online survey is conducted by an external research company on behalf of Hydro One. It measures the opinions of customers and seeks to uncover perceptions of how well Hydro One meets their expectations. Because of the relatively small size of this customer base, all LTX customers are invited to participate in this online survey, with the goal of collecting feedback from as many customers as possible.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Over the 2021-2025 period, average customer satisfaction was 86%. Overall satisfaction was below the target for 2024 (85%) and 2025 (79%) as shown in Table 3. Customer satisfaction scores have experienced a decline due, in part, to rapid load growth and connection demand outpacing available capacity and delays due to supply chain constraints. While the reported scores were below target, the limited sample size of LTX customers means these differences in scores cannot be distinguished from normal sampling variation with statistical confidence. Smaller sample sizes are associated with larger margins of error, meaning that survey results are more susceptible to year-to-year variation. Given the inherent variability associated with small sample sizes, the target is being reviewed to ensure it remains an appropriate measure of performance.

Table 3 - Overall Customer Satisfaction (% Satisfied)

	2021	2022	2023	2024	2025	Trend
Target	88%	88%	88%	88%	88%	
Actual	92%	88%	88%	85%	79%	▼

TARGETS

Hydro One is committed to improving satisfaction levels for LTX customers. Throughout 2025, Account Executives were focused on strengthening direct relationships, increasing transparency, and leading webinars, education, and collaboration sessions. Considerable focus will be placed on Hydro One's ongoing commitments to promptly resolve issues raised by customers and make doing business with Hydro One easier. To achieve these commitments, Hydro One is reviewing processes and practices to ensure Hydro One delivers on its promises and is responsive to the needs of these customers.

For the 2028-2032 period, Hydro One will target an average of 85% overall customer satisfaction, beginning with 84% in 2028 and increasing to 86% by 2031. These targets balance demand and capacity challenges with Hydro One's aim to deliver consistent and high-quality customer service.

Table 4 - Overall Customer Satisfaction Targets

	2026	2027	2028	2029	2030	2031	2032
Target	88%	88%	84%	85%	85%	86%	86%

2.5.3.2.2 SATISFACTION WITH OUTAGE PLANNING PROCEDURES (PERCENT SATISFIED)

Performance Category	Measures	Description
Customer Satisfaction	Satisfaction with Outage Planning Procedures (% Satisfied)	This measure captures the satisfaction with planned outage management among customers within the three major transmission-connected (LTX) segments (Transmission End Users, Local Distribution Companies (LDC) and Transmission-Connected Generators) who have experienced a planned outage in the past year.

Hydro One measures satisfaction with the outage planning procedures among LTX customers as part of the annual CSAT survey discussed above. To capture their level of satisfaction with outage planning procedures, LTX customers who recall experiencing a planned outage in the past year are asked to express their satisfaction/dissatisfaction with the way planned outages are managed by Hydro One, using a five-point scale. Hydro One also analyzes the responses to an open-ended follow-up question about possible improvements in the outage management process**.** This metric is measured and reported to Large Customer Accounts and Operating Planning on a combined basis for Hydro One Transmission and HOSSM.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Over the 2021-2025 period, average customer outage planning process satisfaction was 81%. The outage planning process satisfaction was above the target for 2024 (88%) and slightly below target for 2025 (84%) as shown in Table 5.

Hydro One continues to maintain strong system reliability across the province for multi circuit connections, placing it in the first quartile for outage duration and generally in the second quartile for outage frequency. However, the significant increase in workload driven by growth and development requires much greater coordination with customers. This has the potential for increased customer impact, particularly for radial fed connections, and may have contributed to a slight decline in outage planning satisfaction.

Hydro One sent email invitations and reminders to all of its LTX customers to participate in the annual CSAT survey. In several years (2022, 2023, and 2025), the participation rate on the operating planning survey portion remained below 30%. With a smaller sample size, individual responses, particularly outliers, have a proportionally larger impact on the overall score, resulting in a higher margin of error. Therefore, the decrease in satisfaction scores may not be reflective of systemic change in customer service.

Table 5 - Satisfaction With Outage Planning Procedures (% Satisfied)

	2021	2022	2023	2024	2025	Trend
Target	87%	87%	85%	85%	85%	
Actual	82%	78%	72%	88%	84%	▲

TARGETS

Hydro One is working to improve its outage planning process for transmission-connected customers and is targeting an average of 82% satisfaction with outage planning procedures over the 2028-2032 period. These targets balance demand and capacity challenges with Hydro One's aim to deliver consistent and high-quality customer service.

Table 6 - Outage Planning Procedures Targets

	2026	2027	2028	2029	2030	2031	2032
Target	85%	85%	81%	82%	82%	83%	83%

2.5.4 OPERATIONAL EFFECTIVENESS

These measures demonstrate Hydro One's commitment to continuous improvement in performance and execution. They show how Hydro One delivers on safety, system reliability, asset and project management, and cost control.

2.5.4.1 SAFETY

2.5.4.1.1 RECORDABLE INJURY RATE (NUMBER OF RECORDABLE INJURIES/ILLNESSES PER 200,000 HOURS WORKED)

Performance Category	Measures	Description
Safety	Recordable Rate (# Recordable Injuries/Illnesses per 200,000 hours worked)	Work-related injuries/illnesses that result in: restricted work, lost time, loss of consciousness, medical attention beyond first aid, death, or any other significant work-related injury or illness diagnosed by a physician or other healthcare professional and are confirmed by a Hydro One Occupational Health Nurse. The measure applies to Hydro One employees only (not contractors).

Hydro One has made significant progress in improving the rate of recordable injuries, which is a standardized safety calculation that is used to compare safety performance amongst utilities. Hydro One's recordable injuries have remained below target for several years, and our recordable injury rate is below 1.0, which is considered industry-leading among peer utilities. Hydro One's recordable injury rate measures the number of work-related injuries or illnesses per 200,000 hours worked which results in: restricted work; medical attention beyond first aid; or a fatality and is confirmed by a Hydro One Occupational Health Nurse. This measure only applies to employees of Hydro One and excludes contractors and the general public.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Over the 2021-2025 period, Hydro One's Recordable Injury rate remained below annual targets.

Table 7 - Recordable Injury Rate
(# Recordable Injuries/Illness per 200K Hours Worked)

	2021	2022	2023	2024	2025	Trend
Target	1.0	0.9	0.9	0.9	0.9	
Actual	0.7	0.6	0.6	0.6	0.7	▼

Hydro One's performance is attributable to its focus on safety, which is engrained in its culture and corporate strategy aimed at becoming the safest and most efficient utility. Hydro One continues to adopt the philosophy that a safe utility is also an efficient utility and focuses on: effective job planning, operational discipline, strong field leadership, regular safety meetings, comprehensive workplace safety observations, ongoing training and development, trades mentorship programs, and robust safety catch analysis.

TARGETS

Over the 2028-2032 period, Hydro One aims to maintain industry-leading safety performance with a Recordable Injury Rate of less than 0.8 recordable injury/illness per 200,000 hours worked, as presented in the table below.

Table 8 - Recordable Injury Rate Targets

	2026	2027	2028	2029	2030	2031	2032
Target	0.9	0.9	0.8	0.8	0.8	0.8	0.8

The following safety initiatives are underway to reduce high-impact injuries: using incidents as a learning opportunity; improving control-effectiveness to reduce risk; improving the effectiveness of workplace safety observations; conducting in depth investigations with meaningful corrective actions; and placing a greater focus on the Human Performance program. The Human Performance program identifies situations in which potential errors could result in workplace injuries, customer interruptions, or damage to assets and equipment, and recommends tools and behaviours to minimize the likelihood of such errors. In addition, Hydro One is advancing psychological safety through leadership presentations and programs designed to foster a consistent and supportive environment, promote proactive measures that protect employee wellbeing, and establish clear accountability mechanisms to ensure program effectiveness.

2.5.4.2 SYSTEM RELIABILITY

Hydro One tracks and measures the reliability of its electricity transmission system using five measures, defined as:

1. Transmission System Average Interruption Frequency Index – Sustained (T-SAIFI-S);
2. Transmission System Average Interruption Frequency Index – Momentary (T-SAIFI-M);
3. Transmission System Average Interruption Duration Index – (T-SAIDI);
4. System Unavailability; and
5. Unsupplied Energy.

Consistent with industry practice, Hydro One removes extraordinary events from its delivery point reliability metrics.[1] Extraordinary events are those like the 1998 Ice Storm,

[1] Since the impact of these events on equipment performance is not as significant as their impact on delivery points, no event has been excluded from System Unavailability metrics, which is based on equipment performance.

the 2003 Northeastern Blackout and 2013 GTA Flood whose impact exceeds one million MW-minutes. These events have an "excessive" impact on the transmission system and skew the historical trend of the measures.

In addition, when reporting on Transmission Scorecard measures,[2] Hydro One includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.
The exclusion threshold for major events has been determined using a statistical method (log-standard deviation (β)) resulting in a threshold of 10,000 MW-minutes being used to exclude major unsupplied energy events from the reliability metrics. Interruptions are excluded if the event is over 10,000 MW-minutes and the individual interruptions are not considered to be controllable by Hydro One. This causes equipment and human error caused interruptions to still count in scorecard metrics while excluding extreme events outside of Hydro One control. Hydro One began applying this exclusion threshold to performance tracking and target setting starting in 2019.

Further information on transmission reliability may be found in TSP Section 2.4.

2.5.4.2.1 T-SAIFI-S (AVERAGE NUMBER OF SUSTAINED INTERRUPTIONS PER DELIVERY POINT)

Performance Category	Measure	Description
System Reliability	T-SAIFI-S (Average Number of Sustained Interruptions per Delivery Point)	Transmission System Average Interruption Frequency Index - Sustained is the average number of unplanned interruptions that customers (delivery points) experienced. The measure is presented as the number of interruptions per delivery point per year for sustained (1 minute and longer) interruptions only.

T-SAIFI-S is used to measure the average number of unplanned sustained interruptions that customers experienced per Delivery Point in a year.

[2] If an event meets the threshold for an extraordinary event, it is not also considered as a major event to avoid double counting.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

The average number of sustained interruptions per Delivery Point in 2025 was 0.46, a decrease in the index value of 0.06 or about 11.5% compared to 2024, primarily due to fewer weather and equipment caused interruptions.

Hydro One's average performance over the past five years (2021-2025) was 0.53, and the performance trend is moderately decreasing during the past five years (see Figure 2).

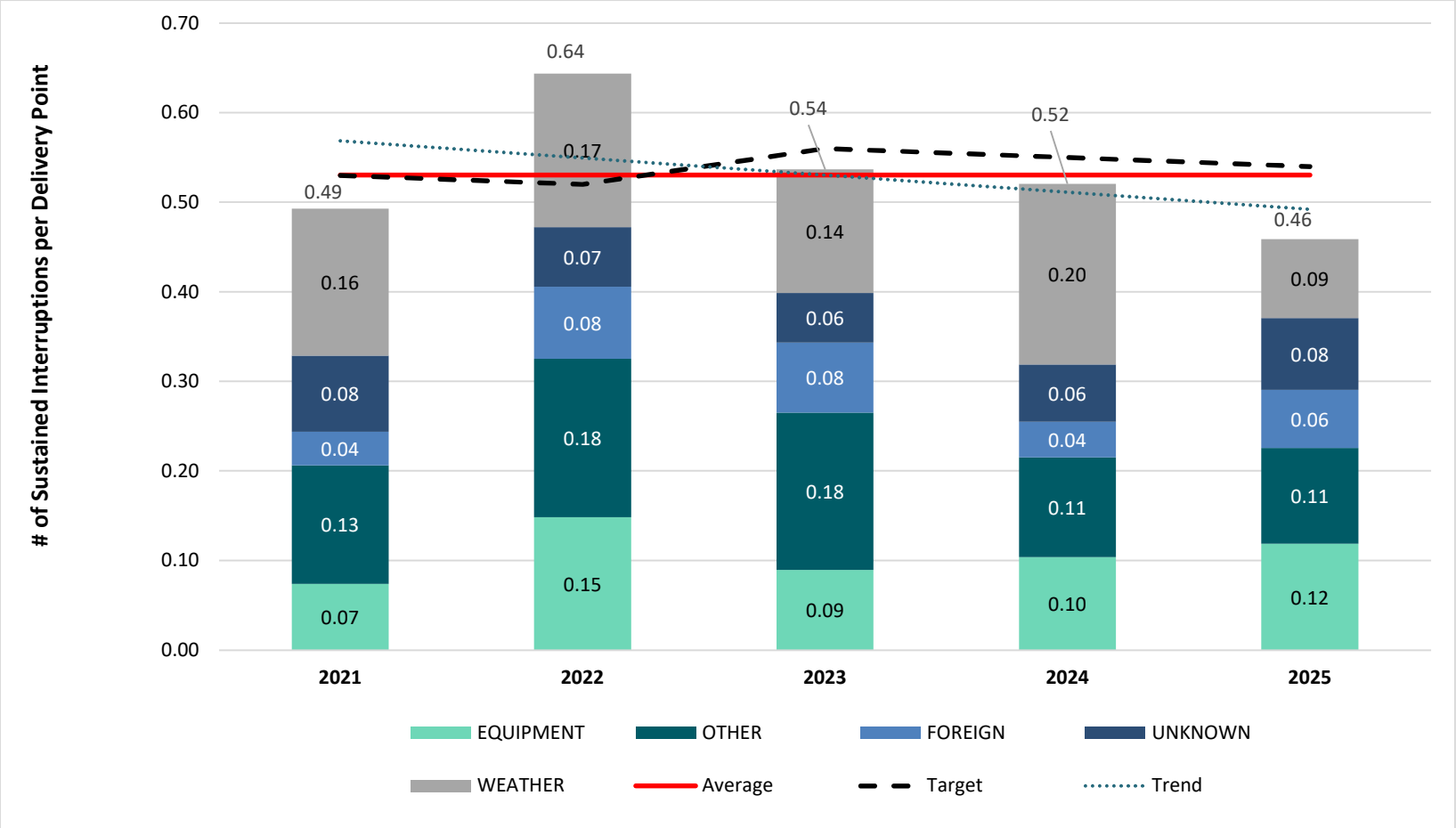

Figure 2: Transmission System Average Interruption Frequency Index - Sustained

Witness: Spencer Gill, Scott Vicary, Anthony Nava, Aimee Oabel, Mark Brodie

TARGETS

Over the 2028-2032 period, Hydro One aims to improve T-SAIFI-S performance by 2% over 5 years from the 2027 target. Targets have been presented in the table below.

Table 9 - T-SAIFI-S Targets

	2026	2027	2028	2029	2030	2031	2032
Target	0.52	0.51	0.51	0.51	0.50	0.50	0.50

2.5.4.2.2 T-SAIFI-M (AVERAGE NUMBER OF MOMENTARY INTERRUPTIONS PER DELIVERY POINT)

Performance Category	Measure	Description
System Reliability	T-SAIFI-M (Average Number of Momentary Interruptions per Delivery Point)	Transmission System Average Interruption Frequency Index - Momentary is the average number of unplanned interruptions that customers (delivery point) experienced. The measure is presented as the number of interruptions per delivery point per year for momentary (less than 1 minute) interruptions only.

T-SAIFI-M is used to measure the average number of unplanned momentary interruptions (less than one minute) that customers experience per Delivery Point in a year.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

The average number of momentary interruptions per Delivery Point in 2025 was 0.26, a decrease in the index value of 0.18 or about 42% compared to 2024, primarily due to fewer weather caused interruptions.

Hydro One's average performance over the past five years (2021-2025) was 0.40 interruptions per Delivery Point, as shown in Figure 3 below.

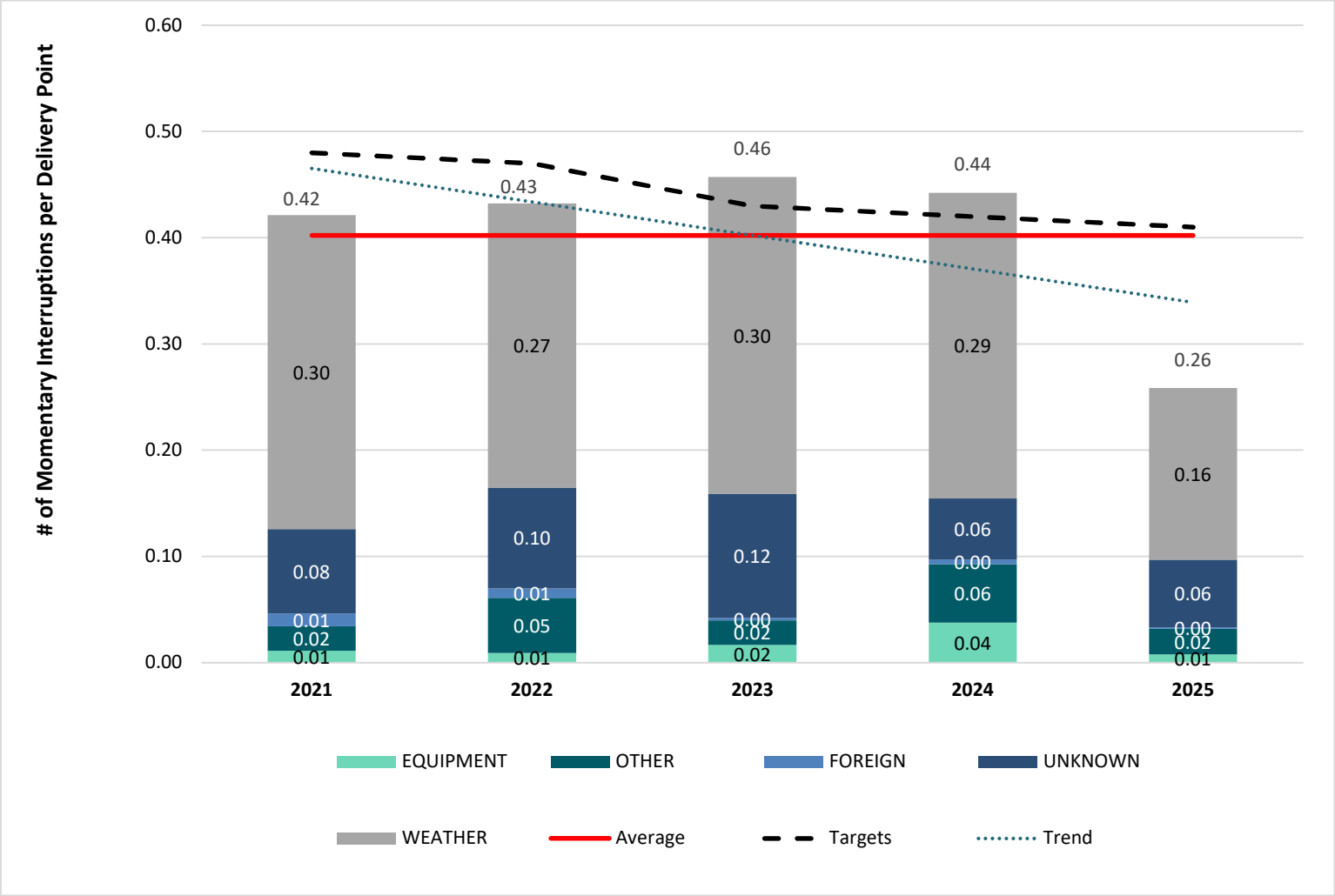

Figure 3: Transmission System Average Interruption Frequency Index - Momentary

Witness: Spencer Gill, Scott Vicary, Anthony Nava, Aimee Oabel, Mark Brodie

TARGETS

Over the 2028-2032 period, Hydro One aims to improve T-SAIFI-M performance by 2% over 5 years from the 2027 target. Targets have been presented in the table below.

Table 10 - T-SAIFI-M Targets

	2026	2027	2028	2029	2030	2031	2032
Target	0.41	0.40	0.40	0.40	0.40	0.39	0.39

2.5.4.2.3 T-SAIDI (AVERAGE MINUTES OF INTERRUPTIONS PER DELIVERY POINT)

Performance Category	Measure	Description
System Reliability	T-SAIDI (Average minutes of Interruptions per Delivery Point)	Transmission System Average Interruption Duration Index is the average minutes of unplanned interruptions that customers (delivery points) experienced. The measure is presented as interruption minutes per delivery point per year. Only sustained (1 minute and longer as per the Canadian Electricity Association (CEA) industry standard) interruptions contribute to this measure.

T-SAIDI is used to measure the average minutes of unplanned interruptions (one minute and longer) that customers experience per Delivery Point in a year.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

The average duration of sustained interruptions per Delivery Point in 2025 was 18.5 minutes, a decrease of 5.2 minutes or about 22% compared to 2024.

Hydro One's average performance over the past five years (2021-2025) was 29.9 minutes (see Figure 4 below) and the five-year performance is improving based on declining trend. T-SAIDI performance can vary significantly from year to year for the following reasons:

- a small number of Delivery Points can cause the index to fluctuate appreciably;
- a small number of events can cause the index to fluctuate appreciably;
- major events are distributed randomly over the years; and

- radial supplied Delivery Point performance can vary significantly because these Delivery Points lack alternative means of supply in the event of an interruption.

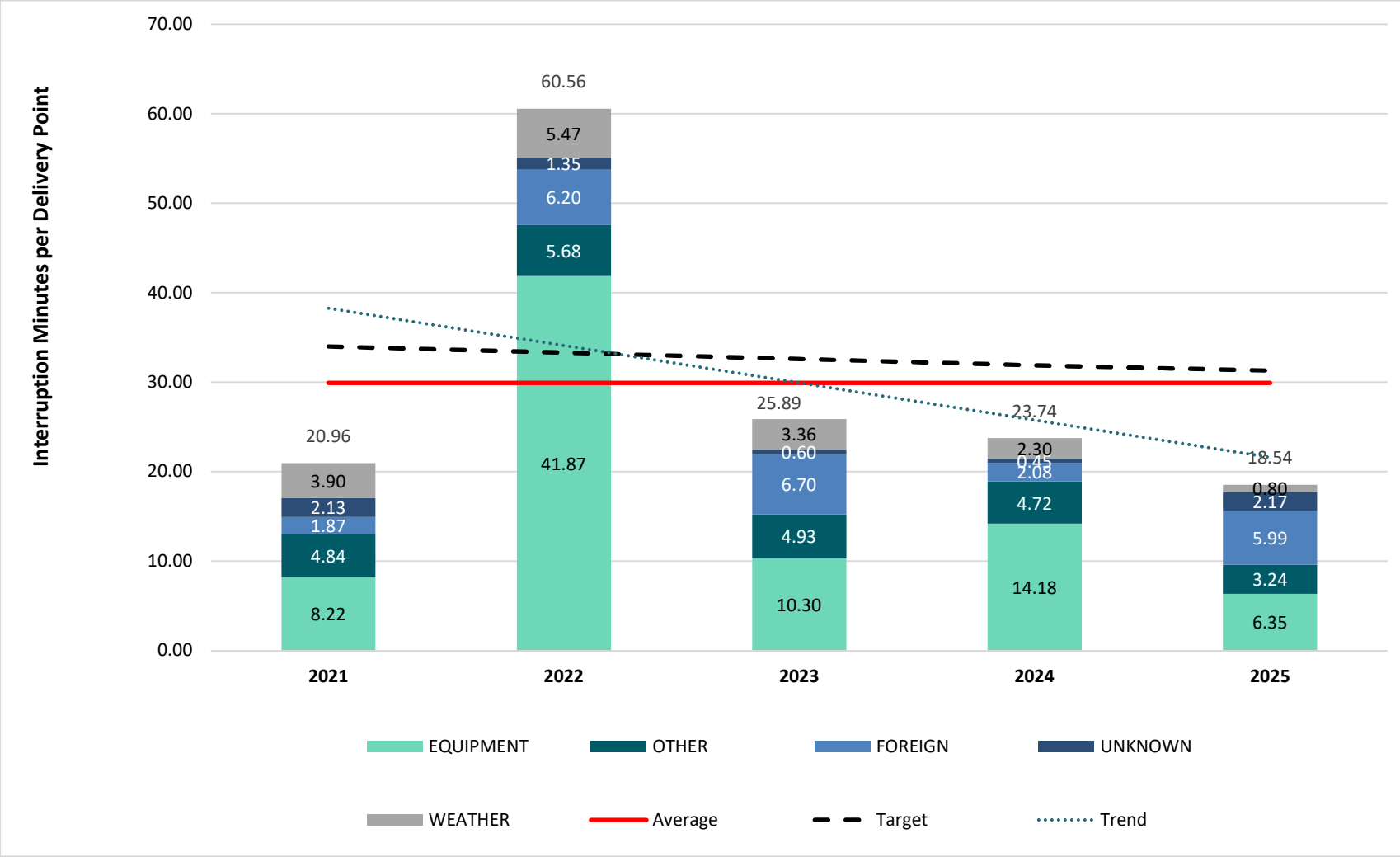

Figure 4: Transmission System Average Interruption Duration Index (Minutes)

Witness: Spencer Gill, Scott Vicary, Anthony Nava, Aimee Oabel, Mark Brodie

TARGETS

Over the 2028-2032 period, Hydro One aims to improve T-SAIDI performance by 2% over 5 years from the 2027 target. Targets have been presented in the table below.

Table 11 - T-SAIDI Targets

	2026	2027	2028	2029	2030	2031	2032
Target	30.7	30.1	30.0	29.9	29.7	29.6	29.5

2.5.4.2.4 SYSTEM UNAVAILABILITY (% OF TIME SYSTEM EQUIPMENT IS UNAVAILABLE)

Performance Category	Measure	Description
System Reliability	System Unavailability (% of time system equipment is unavailable)	Transmission System Unavailability captures the total duration that transmission equipment is out of service due to unplanned outages.

System Unavailability measures the unavailability of transmission lines and major transmission station equipment,[3] due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. While equipment unavailability doesn't necessarily lead to interruptions due to redundancy on Hydro One's transmission system, it is a leading indicator of future reliability erosion.

The information derived from monitoring this measure is trended over time and influences business decisions that improve the reliability of transmission equipment.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

For 2025, System Unavailability was 0.63%, which is 0.13 higher than the 2024 result. System unavailability in 2025 was largely driven by long duration outages on breakers,

[3] Major station equipment includes: Transmission lines, High voltage cables, Breakers, Transformers, Shunt capacitor banks, Shunt reactors, Series capacitor banks and Static VAR Compensators.

disconnect switches and control issues on reactive power components. Historical System Unavailability is presented in the table below.

Table 12 - System Unavailability (% Time Unavailable)

	2021	2022	2023	2024	2025	Trend
Target	0.64%	0.63%	0.62%	0.61%	0.60%	
Actual	0.67%	0.76%	0.52%	0.50%	0.63%	▼

Hydro One's average System Unavailability over the past five years (2021-25) was 0.62% and the performance trend is improving, as indicated by the declining trend in system unavailability over this period.

TARGETS

Over the 2028-2032 period, Hydro One aims to improve System Unavailability performance by 2% over 5 years from the 2027 target. Targets have been presented in the table below.

Table 13 - System Unavailability (% Time Unavailable) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	0.59%	0.58%	0.58%	0.58%	0.57%	0.57%	0.57%

2.5.4.2.5 UNSUPPLIED ENERGY (SYSTEM MINUTES)

Performance Category	Measure	Description
System Reliability	Unsupplied Energy (System Minutes)	Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points.

Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to allow comparison with the performance of different sized utilities.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Unsupplied Energy for 2025 was 5.7 minutes, lower by approximately 2.5 minutes or about 30% compared to 2024 primarily due to fewer equipment-caused interruptions. Due to the limited number of Delivery Points, substantial fluctuations can occur from one year to the next. Historical Unsupplied Energy is presented on the table below.

Table 14 - Unsupplied Energy (System Minutes)

	2021	2022	2023	2024	2025	Trend
Target	9.4	9.2	9.0	8.8	8.6	
Actual	7.1	13.3	6.4	8.2	5.7	▼

Hydro One's average performance over the past five years (2021-2025) was 8.1 minutes of unsupplied energy and the performance trend is improving.

TARGETS

Over the 2028-2032 period, Hydro One aims to improve Unsupplied Energy performance by 2% over 5 years from the 2027 target. Targets have been presented in the table below.

Table 15 - Unsupplied Energy (System Minutes) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	8.4	8.2	8.2	8.1	8.1	8.1	8.0

2.5.4.3 ASSET & PROJECT MANAGEMENT

The measures in this group track Hydro One's performance in accomplishing the work necessary for the safe and reliable operation of the Transmission System. This work includes the investments necessary to renew the system, maintain service to customers, and expand the system to serve new customers or accommodate infrastructure development. The measures address capital investments and Operations, Maintenance, & Administration spending.

2.5.4.3.1 TRANSMISSION SYSTEM PLAN IMPLEMENTATION PROGRESS

Performance Category	Measure	Description
Asset & Project Management	Transmission System Plan Implementation Progress	The Transmission System Plan Implementation Progress measure compares the total actual in-year expenditures for in-service additions to the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance.

In-service capital additions are tracked and reported in a manner consistent with the regulatory requirements of the transmission business and reported as a percentage value relative to the transmission plan.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One's average performance over the 2023-2025 period was 94%. Transmission System Plan Implementation progress is presented in the table below.

Table 16 - Transmission System Plan Implementation Progress

	2021	2022	2023	2024	2025	Trend
Target	100%	100%	100%	100%	100%	
Actual	99%	101%	97%	95%	91%	▼

Over the 2023-2025 period, Transmission System Plan Implementation was slightly below target primarily due to the following project and program changes:

- Reprioritization of several transmission line refurbishment projects to accommodate emerging, non-discretionary system growth investments and required system upgrades across the broader portfolio.
- Scope reduction and re-pacing of the Gardiner TS: T1/T2 PCT Component Replacement project due to equipment failure which is now expected to be in-service in 2026.
- A reduction to the Transmission Lines Insulator Replacement program which was impacted by system outage constraints and diversion of crews to ice storm and wildfire restorations.

- The above re-pacing and scope reductions were largely offset by acceleration of the Bruce A 500kV Switchyard Replacement project that led to a significant project milestone in 2025, reflecting the advancement of in-service additions from 2026 and led to reductions in the overall project cost.

TARGETS

Over the 2028-2032 period, Hydro One aims to complete 100% of the annual planned in-service additions.

Table 17 - Transmission System Plan Implementation Progress (%) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	100%	100%	100%	100%	100%	100%	100%

2.5.4.3.2 CAPITAL EXPENDITURES AS A % OF OEB APPROVED PLAN

Performance Category	Measure	Description
Asset & Project Management	Capital Expenditures as % of OEB Approved Plan	Progress is measured as the ratio of actual total capital expenditures to the total amount of planned capital expenditures.

Hydro One measures the progress of its capital expenditures as the ratio of actual total capital expenditures to the total amount of planned capital expenditures.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One's average performance over the 2023-2025 period was 107%. Capital expenditures as percent of the OEB approved plan are presented in the table below.

Table 18 - Capital Expenditures (% of OEB Approved Plan)

	2021	2022	2023	2024	2025	Trend
Target	100%	100%	100%	100%	100%	
Actual	112%	114%	97%	114%	109%	▼

Over the 2023-2025 period, capital expenditure was slightly above target primarily due to the following changes:

- An increase in externally driven work, including the Waasigan Transmission Line Project (station portion), Centennial TS: Project Connect PowerCo project, St. Clair Transmission Line project (station portion), and the Holt Switching Station SMR Connection.
- Persistent and elevated inflation, resulting in significant increases in the cost of key electrical equipment and materials, as detailed in SPF Section 1.8.
- Increased costs for Bruce A 500kV Switchyard Replacement due to significant material/equipment cost increases, coupled with additional infrastructure needs. Efforts to accelerate the project helped to partially offset these increases and led to $30M in cost reductions due to reduced contingency and commissioning costs.
- The above increases were substantially offset by deferral of several transmission line refurbishment projects, to accommodate non-discretionary system growth investments and required system upgrades across the broader portfolio.
- At the same time, Hydro One has actively pursued cost-mitigation opportunities. This included rigorous review of active projects to identify cost efficiencies and mitigate variances. These efforts have resulted in forecast cost reductions across many projects as discussed in TSP Section 2.9.

TARGETS

Over the 2028-2032 period Hydro One aims to complete 100% of the annual planned Capital Expenditures.

Table 19 - Capital Expenditures (% of OEB Approved Plan) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	100%	100%	100%	100%	100%	100%	100%

2.5.4.3.3 OM&A PROGRAM ACCOMPLISHMENT (COMPOSITE INDEX)

The OM&A Program Accomplishment Composite Index compares the weighted actual in-year accomplishment for key Station Services Preventative Maintenance and Vegetation Management programs against the weighted budget. The index covers the major components of Hydro One's preventative maintenance portfolio and represents the core activities required to maintain the reliability and safe operation of transmission station

assets under the OM&A envelope including maintenance work related to line clearing and brush activities.

The Composite Index includes eight programs; two in respect of Vegetation Management: Line Clearing and Brush Control, and six in respect of Station Services Preventative Maintenance programs: Power Equipment, Ancillary Equipment, Protection and Control, Telecom, Infrastructure, and, historically, PCB Testing and Retrofill. These programs reflect the most significant preventative maintenance activities and collectively represent the majority of annual planned maintenance work within Station Services. The index incorporates both programmatic and unit-based accomplishment, with each program weighted according to its relative contribution to asset health, system reliability, and regulatory compliance.

The PCB Testing and Retrofill program was included in the Composite Index through 2025 to track Hydro One's progress in meeting federal PCB phase-out requirements. With the completion of these regulatory obligations, the program will be removed from the Composite Index beginning in 2026, and its weighting will be reallocated among the remaining Station Services Preventative Maintenance programs

Performance Category	Measure	Description
Asset & Project Management	OM&A Program Accomplishment (Composite Index)	The Transmission (Tx) OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) Forestry Line Clearing; 2) Brush Control; 3) PCB Testing and Retro fill; and Station Preventive Maintenance programs which include 4) Power Equipment, 5) Ancillary Equipment, 6) Protection and Control, 7) Telecom, 8) Infrastructure.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

In 2025, Hydro One achieved 97% of its OM&A Program Accomplishment metric. The variance from plan was primarily attributed to the Transmission PCB Reduction Retrofill

program, which was completed ahead of schedule. This variance was partially offset by higher-than-planned accomplishments in the Preventative Maintenance – Planned program, which exceeded its target by 17%.

2024 results were closely aligned with plan, achieving 102% of target accomplishments and reflecting balanced execution across key OM&A programs.

2023 results exceeded plan, achieving 109% of target accomplishments. This was primarily attributable to higher-than-planned PCB sampling and increased vegetation management activities in support of reliability objectives. The higher level of accomplishment in 2023 contributed to variability in planned and achieved accomplishments in subsequent years.

Hydro One's historical five-year average (2021-2025) was 102% which reflects Hydro One’s commitment to completing the planned OM&A work program.

Table 20 - OM&A Program Accomplishment (% of Budget)

	2021	2022	2023	2024	2025	Trend
Target	100%	100%	100%	100%	100%	
Actual	105%	96%	109%	102%	97%	▼

TARGETS

Over the 2028-2032 period Hydro One aims to complete 100% of the OM&A program.

Table 21 - OM&A Program Accomplishment (% of Budget) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	100%	100%	100%	100%	100%	100%	100%

2.5.4.3.4 TRANSMISSION CAPITAL ACCOMPLISHMENT INDEX (TCAI-EXPANDED)

Performance Category	Measure	Description
Asset & Project Management	Transmission Capital Accomplishment Index (TCAI - Expanded)	The TCAI composite index measure compares the weighted actual in-year accomplishment for significant Transmission System Renewal Capital investments against the weighted plan. The investments covered by this metric represent the major assets associated with station and lines refurbishment projects being transformers, breakers, protections and circuit kilometers, as well as five programs including: 1) Insulator Replacement, 2) Wood Pole Replacement, 3) Shieldwire Replacement, 4) Tower Foundation and, 5) Steel Structure Coating, which are the primary drivers for System Renewal investments.

Over the 2023-2027 period, the Transmission Capital Accomplishment Index (TCAI) compares the weighted actual in-year accomplishment for significant Transmission Capital investments against the weighted plan. TCAI includes project based component replacements such as transformers, breakers, protections and conductors as well as programmatic component replacements, including insulators, poles, shieldwire, tower foundations, and steel structure coating. This metric demonstrates Hydro One's ability to complete the planned capital project and program accomplishments within the System Renewal category.

For the 2028-2032 period, Hydro One proposes to expand the TCAI metric to include all planned major unit accomplishments, resulting in greater coverage of the transmission capital portfolio. As part of this update, protection units will be removed from TCAI, and their proportional weighting will be redistributed among the remaining unit types. This change is intended to increase the focus of TCAI on larger, higher-value units, resulting in a metric more reflective of the scale and composition of the transmission capital portfolio.

The TCAI measure is meant to be evaluated in the context of other information presented in the TSP, including the Transmission Capital Performance Reports (see TSP Section 2.9, Attachment 2-4).

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One's TCAI result has been trending higher over the 2023-2025 period, ending with a result of 112% for 2025. This significant achievement in 2025 was mainly due to increased volumes of transformer, circuit breaker and protection units resulting from the advancement of work at Merivale TS and Bruce A TS. Slightly lower volumes in 2023 and 2024 were primarily the result of reduced volumes in the Insulator Replacement program which encountered outage challenges, as well as, fewer transformer unit installations due to outage challenges. Further information on 2023-2025 System Renewal projects and programs performance and variances can be found in the Transmission Capital Performance Reports (see TSP Section 2.9, Attachment 2-4).

Table 22 - TCAI (%)

	2021	2022	2023	2024	2025	Trend
Target	100%	100%	100%	100%	100%	
Actual	99%	80%	91%	95%	112%	▲

TARGETS

For the 2028-2032 period Hydro One will continue to target 100% for this metric. This target includes the expanded definition of TCAI as described above.

Table 23 - TCAI (%) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	100%	100%	100%	100%	100%	100%	100%

2.5.4.4 COST CONTROL

Hydro One measures cost control using four OM&A and capital measures: i) Total OM&A and Capital per Gross Book Value of In-Service Assets; ii) OM&A/Gross Fixed Asset Value (%); iii) Line Clearing Cost per kilometer ($/km); and iv) Brush Control Cost per Hectare ($/Ha).

2.5.4.4.1 TOTAL OM&A AND CAPITAL PER GROSS BOOK VALUE OF IN-SERVICE ASSETS

Performance Category	Measure	Description
Cost Control	Total OM&A and Capital per Gross Book Value of In-Service Assets	Demonstrates transmission cost effectiveness by comparing the ratio of Total Capital and OM&A to Gross Book Value of Fixed Asset costs.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Total OM&A and capital expenditure relative to the gross fixed asset value in 2025 was 7.6%, or 0.9% lower compared to 2024, due to lower OM&A and capital expenditures. Approximately 0.2% of the year-over-year change is attributed to lower OM&A as detailed in Exhibit E-02-01, with the remaining 0.7% associated with lower capital expenditures as detailed in TSP Section 2.9 and a high gross fixed asset base. Total OM&A and Capital per Gross Book Value of In-Service Assets is presented in the table below.

Table 24 - Total OM&A and Capital per Gross Book Value of In-Service Assets

	2021	2022	2023	2024	2025	Trend
Target	7.9%	7.7%	7.9%	8.0%	7.0%	
Actual	8.3%	7.6%	8.6%	8.5%	7.6%	▼

Hydro One's average performance over the past five years (2021-2025) was 8.1%, and performance is moderately lower over the period, mainly due to required reinvestment and maintenance of gross fixed assets.

TARGETS

For 2028, Hydro One is targeting a ratio of 10.8%. Targets for 2028 -2032 will be set based on the OEB approved amounts determined in this Application and through the Custom IR framework's annual update applications.

Table 25 - Total OM&A and Capital per Gross Book Value of In-Service Assets Targets

	2026	2027	2028
Target	6.8%	6.5%	10.8%

2.5.4.4.2 OM&A PER GROSS FIXED ASSET VALUE

Performance Category	Measure	Description
Cost Control	OM&A per Gross Fixed Asset Value	Demonstrates Transmission cost effectiveness by comparing the ratio of OM&A to Gross Book Value of Fixed Asset costs.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

OM&A expenditure per gross fixed asset value was 1.8% in 2025, slightly lower than 2024 performance and but in line with the 2025 target. OM&A/Gross Fixed Asset Value is presented in the table below.

Table 26 - OM&A per Gross Fixed Asset Value

	2021	2022	2023	2024	2025	Trend
Target	1.7%	1.6%	1.9%	1.8%	1.8%	
Actual	2.0%	2.2%	2.4%	2.0%	1.8%	▼

Hydro One's average performance over the past five years (2021-2025) was 2.1%. The OM&A ratio has been stable (trending lower), reflective of consistent levels of OM&A relative to a growing asset base.

TARGETS

For 2028, Hydro One is targeting a ratio of 2.1%. Targets for 2028 -2032 will be set based on the OEB approved amounts determined in this Application and through the Custom IR framework's annual update applications.

Table 27 - OM&A/Gross Fixed Asset Value Targets

	2026	2027	2028
Target	1.8%	1.7%	2.1%

2.5.4.4.3 LINE CLEARING COST PER KILOMETER ($/KM)

Performance Category	Measure	Description
Cost Control	Line Clearing Cost per kilometer ($/km)	Cost associated with line clearing activities, per kilometer completed for the year.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One measures the cost of the line clearing program per kilometer cleared annually.

Table 28 - Line Clearing Cost per Kilometer ($/km)

	2021	2022	2023	2024	2025	Trend
Target	$2,200	$2,175	$2,784	$2,854	$2,925	
Actual	$2,211	$2,140	$2,210	$2,426	$2,896	▲

Over the past five years (2021-2025), Hydro One's average line clearing cost was $2,377 per kilometer, and the average annual number of kilometers cleared was 2,682 km. For each of the years 2022-2025, Hydro One's cost per kilometer of line cleared was less than the annual target.

TARGETS

Over the 2028-2032 period, Hydro One aims to achieve line clearing unit costs averaging $2,879, and to execute approximately 4,560 km annually.

Table 29 - Line Clearing Cost per Kilometer ($/km) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	$2,998	$3,073	$2,767	$2,822	$2,879	$2,935	$2,994

2.5.4.4.4 BRUSH CONTROL COST PER HECTARE ($/HA)

Performance Category	Measure	Description
Cost Control	Brush Control Cost per Hectare ($/Ha)	Cost associated with brush control per hectare completed for the year.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One measures the cost of its brush control per hectare completed in the year. Brush Control Cost per Hectare is presented in the table below.

Table 30 - Brush Control Cost per Hectare ($/Ha)

	2021	2022	2023	2024	2025	Trend
Target	$1,630	$1,608	$1,628	$1,669	$1,711	
Actual	$1,807	$2,003	$1,916	$2,402	$2,678	▲

Hydro One's average brush control cost per hectare has increased over the 2021 to 2025 period, reflecting changes in the underlying cost drivers since the original targets were established. One of the primary contributors has been a shift in the labor mix, with a greater proportion of work being completed by regular employees and higher-skilled non-regular resources than originally planned. Fleet and equipment costs have also increased, driven by higher contractor rates for equipment, rising parts costs, greater reliance on equipment rentals, and increased helicopter usage to access remote locations, particularly in Northern service areas.

TARGETS

Hydro One continues to invest in vegetation management across its transmission corridors to address the vegetation that is most likely to impact system reliability. Over the 2028-2032 period, Hydro One is targeting average brush control unit costs of $2,913 and planning to execute 14,199 hectares annually compared to 6,666 hectares executed in 2025.

Table 31 - Brush Control Cost per Hectare ($/Ha) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	$1,754	$1,798	$2,799	$2,855	$2,912	$2,970	$3,030

The 2028-2032 targets were set using 2024-2025 expenditures which reflect recent execution costs, and the following criteria:

- 3-year historical average working hours
- Resource mix with 67% non-regular staff and 33% regular staff

- Year-over-year inflation

Hydro One will continue to maintain the existing line clearing and brush control cycles that have shown to be effective in mitigating transmission system risk. Strategic alignment of work and resource deployment, increasing flexibility in Hydro One's Vegetation Management Standard, and technological improvements will support Hydro One executing this work program over the 2028-2032 period.

2.5.5 PUBLIC POLICY RESPONSIVENESS

The measures in this category demonstrate Hydro One's commitment to deliver on obligations mandated by the government and regulatory agencies.

2.5.5.1 CONNECTION OF GENERATION

2.5.5.1.1 ON-TIME COMPLETION OF CUSTOMER IMPACT ASSESSMENTS ON RENEWABLE GENERATION (REMOVE)

Performance Category	Measure	Description
Connection of Generation	On-time completion of Customer Impact Assessments on Renewable Generation	For Transmission-connected generators, Hydro One is obligated under the Transmission System Code to complete a customer impact assessment (CIA) for renewables in 150 days.

Historically under this metric, Hydro One measured its performance as the successful completion of customer impact assessments (CIA) of transmission connected renewable generators within 150 days under the O. Reg. 326/09. However, in 2021 O. Reg. 326/09 was revoked and replaced by O. Reg. 379/21, eliminating the regulatory framework that previously necessitated this renewables-specific metric.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Since 2023, Hydro One did not receive any renewable generation CIA requests, resulting in no assessments requiring completion during the year.

TARGETS

Hydro One is proposing to remove this metric because the regulatory provisions under O. Reg. 326/09 that established a distinct 150-day timeline for completion of assessments for renewable generation connections no longer exists. With this revocation, renewable generation projects are now treated under the same connection assessment framework as all other transmission-connected generators, without a separate timeline requirement.

As a result, maintaining a standalone metric for “renewables CIAs” is no longer relevant or reflective of the current regulatory requirements. Furthermore, in recent years Hydro One has had no renewable-specific CIA requests, further supporting the removal of this metric. Thus, no future targets are required.

2.5.5.1.2 RESOURCE ENABLEMENT (CONNECTIONS & MW ENABLED) (NEW)

Performance Category	Measure	Description
Connection of Generation	Resource Enablement (Connections & MW Enabled)	This measure indicates Hydro One’s performance in meeting ongoing Generation Connection obligations by tracking the MWs of generation placed in service each year. Performance is assessed based on the successful completion and in-service delivery of projects required to support generator connections to the transmission system.

Hydro One is proposing this new scorecard measure to monitor performance in meeting Generation Connection obligations. In previous years, generation connection activity was limited, however in 2023 the Independent Electricity System Operator’s (IESO) initiated generation procurement processes to deliver additional electricity on an accelerated schedule in both the immediate term and long-term.

This has increased the volume and complexity of generator connection-related work that Hydro One carries out, making the successful delivery of these projects an increasingly important indicator of system readiness and execution capability.

HISTORICAL PERFORMANCE

Table 32 provides the MWs of generation capacity connected each year from 2021-2025.

Table 32 - Resource Enablement (MW)

	2021	2022	2023	2024	2025	Trend
Target	NA	NA	NA	NA	NA	
Actual	0	0	286	0	850	▲

TARGETS

The volume of generation connections is primarily driven by the IESO's procurement activities and the timing and size of awarded projects. While the IESO has identified a long-term objective of connecting approximately 15,000 MW of new generation through multiple ongoing procurement phases since 2023, the specific projects, capacities, and in-service dates resulting from future procurement cycles remain uncertain until contracts are awarded. Hydro One therefore cannot establish a fixed long-term target based on future procurement outcomes, however, the IESO has already awarded contracts for approximately 4300 MW of new generation resources, which are anticipated to be connected between 2026 and 2030.

Hydro One proposes to report the actual megawatts (MW) of generation capacity connected each year, based on projects that have been awarded and in-serviced. This approach provides transparency regarding Hydro One's delivery of generation connection obligations while recognizing that the underlying workload is determined by IESO procurement decisions and customer project development activities.

2.5.5.2 MUNICIPAL ENGAGEMENT FOR REGIONAL INFRASTRUCTURE PLANNING (NEW)

2.5.5.2.1 EMAIL COMMUNICATION SENT TO MUNICIPALITIES PRIOR TO THE START OF REGIONAL PLANNING (NEW)

Performance Category	Measure	Description
Municipal Engagement for Regional Infrastructure Planning	Email communication sent to municipalities with a request for electricity planning input prior to the start of Regional Planning	Measures if Hydro One Transmission has sent advance notification to municipalities with a request for their electricity planning input to be considered by LDCs in their load forecast for regional planning.

In December 2022, OEB's Regional Planning Process Advisory Group (RPPAG) published a Municipal Information Guideline called, "Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector". This Guideline recommends that municipalities provide relevant planning information that would assist Local Distribution Companies (LDCs) in developing their load forecast for regional planning purposes. To facilitate this, Hydro One Transmission is proactively notifying municipalities of upcoming regional planning activities and requesting their input on their community's anticipated electricity growth, development plans, and emission reduction plans for consideration in their associated LDC's load forecast. Hydro One Transmission has been doing this since 2023 via annual email communication to municipalities in regions where regional planning will start in the next 18 months. The intent is to give municipalities sufficient time to prepare their input for the LDC's load forecast. A follow-up reminder email is also sent before regional planning begins. This process supports the OEB's vision outlined in the Guideline and has successfully resulted in improved engagement and stronger coordination between Hydro One, LDCs, and municipalities.

Hydro One is proposing this new scorecard measure because municipal input is important in meeting the electricity supply needs of Ontario's customers and communities in the near and long term. By formally tracking this activity, Hydro One can demonstrate how

improved coordination with municipalities and LDCs directly strengthens demand forecasting and ensures local growth plans are reflected in system planning.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

In 2023, Hydro One Transmission implemented the OEB's recommendation to notify municipalities of upcoming regional planning activities, although no formal measure or target was put in place.

TARGETS

Over the 2028-2032 period, Hydro One proposes to report on this activity and maintain performance at 100%.

Table 33 - Email Communication to Municipalities Prior to the Start of Regional Planning (%) Targets

	2028	2029	2030	2031	2032
Target	100%	100%	100%	100%	100%

2.5.5.3 REGIONAL INFRASTRUCTURE PLANNING AND LONG-TERM ENERGY PLAN RIGHT SIZING

2.5.5.3.1 REGIONAL INFRASTRUCTURE PLANNING PROCESS - DELIVERABLES MET

Performance Category	Measure	Description
Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right Sizing	Regional Infrastructure Planning Progress - Deliverables met	Measures progress in meeting the deliverables including meeting the Transmission System Code prescribed timelines and delivering the required products. The number of deliverables will vary in a given year. Deliverables include regional planning reports.

To drive performance relative to the Public Policy Responsiveness outcome, Hydro One measures the performance of its Regional Infrastructure Planning process. Since its inception in 2013, Hydro One measures the percentage of deliverables completed within the prescribed timelines in the Transmission System Code, which includes plans, Regional

Planning reports and LDC Planning Status letters for their rate applications. As part of the first and second regional planning cycles, more than 130 planning reports and planning status letters were completed. The third cycle of regional planning is currently underway and Hydro One has completed more than 25 planning reports and planning status letters. These reports are published on the Hydro One website. Hydro One also files an Annual Status Report with the OEB on November 1 of each year detailing its performance.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Since 2022, Hydro One met 100% of its regional infrastructure planning deliverable obligations, within the allotted time. Hydro One attributes its consistent performance to its well-defined process and to working in close coordination on activities with LDCs and the IESO.

Table 34 - Regional Infrastructure Planning Progress (%)

	2021	2022	2023	2024	2025	Trend
Target	100%	100%	100%	100%	100%	
Actual	95%	100%	100%	100%	100%	▶

TARGETS

Over the 2028-2032 period, Hydro One plans to maintain its performance at 100%.

Table 35 - Regional Infrastructure Planning Progress (%) Targets

	2026	2027	2028	2029	2030	2031	2032
Target	100%	100%	100%	100%	100%	100%	100%

2.5.5.3.2 LONG-TERM ENERGY PLAN END-OF-LIFE RIGHT-SIZING ASSESSMENT EXPECTATIONS

Performance Category	Measure	Description
Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right Sizing	Long Term Energy Plan End-of-Life Right-Sizing Assessment Expectation	This qualitative measure gauges Hydro One's performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing end-of-life equipment are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

This measure was first identified in 2017 Long Term Energy Plan (LTEP) to improve the process used to assess assets at end of life (EOL) and ensure proper right-sizing is considered during the regional planning process. In 2021, the OEB's Regional Planning Process Advisory Group's report also documented this recommendation and further elaborated that a ten-year outlook be provided in the Needs Assessment (NA) report. Hydro One made changes to the Regional Planning process to ensure that a ten-year outlook of major transmission assets that are nearing EOL are adequately assessed by the regional planning Technical Working Group and recommendations are documented in the planning reports. Based on condition assessment, this application includes over 70 EOL assets projects that have been assessed to be replaced with right size consideration.

In the past five years, Hydro One has met 100% of its End-of-Life Right Sizing Assessment Expectations and expects the same over the period 2028 to 2032.

Table 36 - End-of-Life Right-Sizing Assessment Expectation

	2021	2022	2023	2024	2025	Trend
Target	Met	Met	Met	Met	Met	
Actual	Met	Met	Met	Met	Met	▶

TARGETS

Over the 2028-2032 period, Hydro One plans to continue achieving a "Met" score.

Table 37 - End-of-Life Right-Sizing Assessment Expectation Targets

	2026	2027	2028	2029	2030	2031	2032
Target	Met	Met	Met	Met	Met	Met	Met

2.5.5.3.3 REGIONAL PLANNING RESPONSIVENESS (NEW)

Performance Category	Measure	Description
Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right Sizing	Regional Planning Responsiveness	This measure tracks Hydro One's proactive planning for emerging regional electricity demand by accelerating the regional planning cycle for region(s).

Hydro One is proposing a new scorecard measure to track accelerated planning cycles for regions triggered by unforeseen growth and/or Local Distribution Company (LDC) requests and/or government directives. This allows Hydro One to a) help LDCs including the Ontario Energy Board to assess their rate applications and b) assess emerging system needs earlier and support timely planning to meet future demand. Performance is measured by the number of Needs Assessment reports initiated before prescribed timelines.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

The table below provides the number of accelerated Needs Assessment reports each year from 2021-2025.

Table 38 - Regional Planning Responsiveness

	2021	2022	2023	2024	2025	Trend
Actual Accelerated Needs Assessment Reports	0	1	0	2	0	▲

TARGET

Over the 2028-2032 period, Hydro One will monitor and report on the actual number of Needs Assessment reports that were initiated before prescribed timelines. A target is not being set for this measure, as the need for accelerated planning is driven by external factors outside of Hydro One's control, such as unforeseen growth, customer needs, and/or government direction. The measure will provide transparency regarding Hydro

One's responsiveness to emerging planning requirements by reporting on the number of accelerated Needs Assessment reports .

2.5.6 FINANCIAL PERFORMANCE

2.5.6.1 FINANCIAL RATIOS

The measures below were selected to provide financial visibility and to demonstrate that the continuous improvements in execution and cost performance highlighted in 'Operational Effectiveness' are sustainable. The measures used for the Transmission Scorecard align with the Financial Ratio measures used in the Electricity Distributor Scorecard.

2.5.6.1.1 LIQUIDITY: CURRENT RATIO

Performance Category	Measures	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 is defined as cash or other assets to be converted to cash within the year. Current liabilities is defined as short term debts or financial obligations that become due within the year.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One reported a current ratio of 0.25 for the transmission segment in 2025. The 2025 result indicates that for every one dollar of current liabilities, Hydro One had $0.25 in current assets.

Table 39 - Liquidity: Current Ratio

	2021	2022	2023	2024	2025	Trend
Actual	0.27	0.23	0.21	0.21	0.25	▼

Hydro One's average current ratio over the past five years (2021-2025) has been consistent. Due to the nature of this measure, Hydro One has not provided a forecast outlining future financial performance expectations.

2.5.6.1.2 LEVERAGE: TOTAL DEBT TO EQUITY RATIO

Performance Category	Measures	Description
Financial Ratios	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	The debt-to-equity ratio is a measure of Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60 per cent to 40% debt-to-equity structure (a ratio of 1.5).

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One's total debt to equity ratio as measured for its transmission segment was 1.72 in 2025. The debt-to-equity ratio is a measure of Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill creditor obligations.

Table 40 - Leverage: Total Debt to Equity Ratio

	2021	2022	2023	2024	2025	Trend
Actual	1.40	1.37	1.48	1.65	1.72	▲

Hydro One's average debt to equity ratio over the past five years (2021-2025) was 1.52, which aligns with the OEB-deemed ratio of 1.50.

2.5.6.1.3 PROFITABILITY: ACHIEVED REGULATORY RETURN ON EQUITY

Performance Category	Measures	Description
Financial Ratios	Profitability: Regulatory Return on Equity -Deemed Return on Equity (included in rates)	Measures the OEB-approved Return on Equity that is embedded in the transmitter's base rates. Return on Equity is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One's 2025 achieved regulatory return on equity (ROE) was 12.72% for its transmission segment, against an OEB-deemed ROE of 9.36%. The 2025 achieved ROE was higher than deemed primarily due to higher demand driven by external factors including weather-related variability, and other factors including timing of in-service additions.

Table 41 - Regulatory Return on Equity - Deemed Return on Equity

	2021	2022	2023	2024	2025	Trend
Deemed	8.52%	8.52%	9.36%	9.36%	9.36%	
Actual	9.30%	9.92%	10.80%	10.96%	12.72%	▲

Due to the nature of this measure, Hydro One has not provided a forecast outlining future financial performance expectations, except that the company strives to achieve the OEB deemed return.

Fiscal 2023 Hydro One Networks Electricity Transmitter Scorecard, Management Discussion and Analysis ("Scorecard MD&A")

Hydro One Networks Electricity Transmitter 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 2023 One Transmission Scorecard is attached and the discussion is set out below.

Service Quality

- **Customer Delivery Point Performance - Standard Outliers as Percent of Total Delivery Points**

  The Customer Delivery Point Performance is a service quality metric that is measured as the number of standard performance outliers (using standards set by the OEB) as a percentage of the total number of Hydro One delivery points. Customer Delivery Point Performance Standards (CDPPS) were established by the OEB to ensure acceptable transmission reliability experienced at transmission customer delivery points. The group outlier standard defines a delivery point as an outlier if its performance is over the thresholds based on its station load size. The individual outlier standard defines a delivery point as an outlier if its recent two-year's performance is worse than its historical performance. The percentage of outliers to total number of delivery points is measured annually.

  The Standard Outliers as a Percent of Total Delivery Points was 10.9% in 2023, which was slightly better than the target of 11.0%.

[1] EB-2021-0110, Settlement Agreement, Appendix A

Customer Satisfaction

- **Overall Customer Satisfaction**

  This measure reflects the overall satisfaction levels among customers within the three major transmission-connected segments (Transmission End Users, Local Distribution Companies (LDCs) and Transmission-Connected Generators).

  The Overall Customer Satisfaction was 88% in 2023, which met the target of 88%.

- **Satisfaction With Outage Planning Procedures**

  This measure reflects the satisfaction with planned outage management among customers within the three major transmission-connected segments (Transmission End Users, LDCs and Transmission-Connected Generators).

  Satisfaction with Outage Planning Procedures was 72% in 2023, which was less than the target of 85%. The result is attributable to an increase in planned outages on transmission-connected generators.

Safety

- **Recordable Injury - # of recordable injuries/illnesses per 200,000 hours worked**

  The number of recordable injuries/illnesses per 200,000 hours worked measures the work-related injuries or illnesses per 200,000 hours worked which result in: restricted work, lost time, loss of consciousness, medical attention beyond first aid, death, or any other significant work-related injury or illness diagnosed by a physician or other healthcare professional and are confirmed by a Hydro One Occupational Health Nurse. This measure only applies to employees of Hydro One and excludes contractors and the general public.

  The Recordable Injury rate was 0.6 in 2023, which was better than the target of 0.9.

System Reliability

- **T-SAIFI-S (Average Number of Sustained interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Sustained is measured as the total number of unplanned sustained interruptions (1 minute or longer) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Sustained was 0.54 in 2023, which was slightly better than the target of 0.56.

- **T-SAIFI-M (Average Number of Momentary interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Momentary is measured as the total number of unplanned momentary interruptions (less than 1 minute) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Momentary was 0.46 in 2023, which exceeded the target of 0.43. This result is mainly due to an increase in inclement weather and equipment-caused interruptions when compared to the previous 5-year average.

- **T-SAIDI (Average minutes of interruptions per Delivery Point)**

  Transmission System Average Interruption Duration Index is measured as the total number of minutes of unplanned interruptions that customers experienced per Delivery Point in a year. The measure is presented as interruption minutes per delivery point per year. Only sustained (1 minute and longer as per the Canadian Electricity Association (CEA) industry standard) interruptions contribute to this measure. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

The Transmission System Average Interruption Duration Index was 25.9 in 2023, which was better than the target of 32.6.

- **System Unavailability (%)**

  System Unavailability measures the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. While equipment unavailability doesn't necessarily lead to interruptions due to redundancy on Hydro One's transmission system, it is a leading indicator of future reliability erosion.

  Major station equipment includes Transmission lines, High voltage cables, Breakers, Transformers, Shunt capacitor banks, Shunt reactors, Series capacitor banks and Static VAR Compensators. This metric does not take into consideration the subordinate outages of healthy transmission equipment being removed out of service as a result of the outage of some other equipment.

  The System Unavailability was 0.52% in 2023, which was better than the target of 0.62%.

- **Unsupplied Energy (minutes)**

  Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to allow comparison with the performance of different sized utilities.

  The Unsupplied Energy was 6.4 minutes in 2023, which was better than the target of 9.0 minutes.

Asset and Project Management

- **Transmission System Plan Implementation Progress (%)**

  The Transmission System Plan Implementation Progress is measured as the total actual in-year sustainment, development, and operating expenditures for in-service additions over the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance.

  In-service capital additions are tracked and reported in a manner consistent with the regulatory requirements of the transmission business and reported as a percentage value relative to the transmission plan.

  The Transmission System Plan Implementation Progress was 97% in 2023, which was slightly less than the target of 100%. The result is primarily due to timing shifts of System Access and System Renewal projects, partially offset by an increase in System Service projects.

- **CapEx as % of Budget**

  Capex as a percentage of budget is measured as the total actual capital expenditures over the total amount budgeted (planned) capital expenditures in a year. This measure reflects the progress of Hydro One's capital expenditures towards the approved plan.

  The CapEx as a % of Budget was 97% in 2023, which was slightly less than the target of 100%. The result is primarily due to timing shifts of System Access and System Renewal projects, partially offset by an increase in System Service projects.

- **Operations, Maintenance and Administration (OM&A) Program Accomplishment (composite index)**

  The Transmission OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) Forestry Line Clearing; 2) Brush Control; 3) PCB Testing and Retro fill; and Station Preventive Maintenance programs which include 4) Power Equipment, 5) Ancillary Equipment, 6) Protection and Control, 7) Telecom and 8) Infrastructure.

The Transmission OM&A Program Accomplishment composite index was 109 in 2023, which was better than the target of 100.

- **Transmission Capital Accomplishment Index (TCAI) - (%)**

  The TCAI compares the weighted actual in-year accomplishment for significant transmission system renewal capital investments against the weighted budget. The investments covered by this metric represent the major assets associated with station centric and lines refurbishment projects being transformers, circuit breakers, protections and circuit kilometers of transmission line, as well as five programs including insulator replacement, wood pole replacement, shieldwire replacement, tower foundations and steel structure coating.

  The TCAI was 91% in 2023, which was less than the target of 100%. This is attributed to fewer transformer unit installations, steel structures coated, and wood pole replacements being completed due to outage cancellations and material delivery delays, and execution challenges as a result of using composite poles versus wood poles.

Cost Control

- **Total OM&A and Capital per Gross Fixed Asset Value (%)**

  The Total OM&A and Capital per Gross Fixed Asset Value is measured as the total capital and OM&A spend over the total gross book value of in-service assets. This measure demonstrates transmission cost effectiveness.

  The Total OM&A and Capital per Gross Fixed Asset Value was 7.8% in 2023, which was slightly better than the target of 7.9%.

- **OM&A per Gross Fixed Asset Value (%)**

  OM&A per Gross Fixed Asset Value is measured as the total OM&A over the gross book value of fixed assets. The measure demonstrates transmission cost effectiveness.

  The OM&A per Gross Fixed Asset Value was 2.2% in 2023, which exceeded the target of 1.9%. This result is due to higher OM&A driven by increases in corrective maintenance, technology and security expenses.

- **Line Clearing Cost per Kilometer ($/km)**

The Line Clearing Cost per Kilometer is measured as the total line clearing costs over the total number of kilometers of transmission line. This measure shows the cost associated with line clearing activities completed in the year, per kilometer of line.

The Line Clearing Cost per Kilometer was $2,210 in 2023, which was better than the target of $2,784.

- **Brush Control Cost per Hectare ($/Ha)**

  The Brush Control Cost per Hectare is measured as the total cost of brush control completed in the year, per hectare of brush.

  The Brush Control Cost per Hectare was $1,916 in 2023, which exceeded the target of $1,628. This result is due to increased costs associated with more remote work than planned.

Connection of Renewable Generation

- **% On-time completion of renewables customer impact assessments**

  For Transmission-connected generators, Hydro One is obligated under the Transmission System Code to complete a customer impact assessment (CIA) for renewables within 150 days. The % of on-time completion of renewables CIAs is measured as the total number of renewables CIAs completed within the required timeline over the total number of renewables CIAs completed in the year.

  No Customer Impact Assessments were reported in 2023.

Regional Infrastructure Planning & Long-Term Energy Plan (LTEP) Right-Sizing

- **Regional Infrastructure Planning progress - Deliverables met, %**

  Regional Infrastructure Planning Progress – Deliverables met measures progress in meeting the deliverables of the regional infrastructure planning process, including meeting the Transmission System Code ("TSC") prescribed timelines and delivering the required products. The number of deliverables will vary in a given year. Deliverables include plans, reports and Local Distribution Companies (LDC) status

update letters. Deliverables met is measured as the number of correct deliverables that meet the TSC prescribed timelines over the total number of deliverables.

The Regional Infrastructure Planning Progress – Deliverables Met was 100% in 2023, which met the target of 100%.

- **End-of-Life Right-Sizing Assessment Expectation**

  This qualitative measure gauges Hydro One's performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing the replacement of end-of-life equipment to facilitate future growth are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year. Measure Calculation: N/A as this is a qualitative measure – either Met or Not Met.

  The End-of-Life Right Sizing Assessment Expectation was met in 2023.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  Liquidity: Current Ratio measures the ratio of 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 will become due within the year.

  The Liquidity: Current Ratio was 0.21 in 2023.

- **Leverage: Total Debt to Equity Ratio**

  The Total Debt to Equity Ratio is measured as the total short-term and long-term debt over the total equity. This measure reflects Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60% to 40% debt-to-equity structure (a ratio of 1.5).

  The Leverage: Total Debt to Equity Ratio was 1.48 in 2023.

- **Profitability: Regulatory Return on Equity**

  Achieved Regulatory Return on Equity (ROE) measures the OEB-approved ROE that is embedded in the transmitter's base rates. ROE is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB.

  The Profitability: Regulated Return on Equity was 10.80% in 2023.

Note to Readers of Fiscal 2023 Scorecard MD&A

The information provided by Transmission Business on their future performance (or what can be construed as forward-looking information) may be subject to several 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 service quality metrics, including their purposes and frequency of measurement; the development of the transmission system and the progress of the implementation of the transmission system plan; the timing for System Access and System Renewal projects and other system renewal projects; performance measurements regarding end-of-life right-sizing equipment assessment opportunities; financial measurements and their implications; 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 Electricity Transmitter Scorecard

Year End Results

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	Actual 2023	JRAP Target 2023
Customer Focus	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs (%)		10.1%	10.9%	11.4%	8.3%	9.3%	10.9%	11.0%
	Customer Satisfaction	Overall Customer Satisfaction (%)		90%	87%	83%	92%	88%	88%	88%
		Satisfaction with Outage Planning Procedures (% Satisfied)		85%	84%	71%	82%	78%	72%	85%
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)		1.1	0.8	0.9	0.7	0.6	0.6	0.9
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)		0.83	0.59	0.50	0.49	0.64	0.54	0.56
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)		0.50	0.43	0.40	0.42	0.43	0.46	0.43
		T-SAIDI (Ave minutes of interruptions per Deliver Point)		70.0	38.9	61.3	21.0	61.0	25.9	32.6
		System Unavailability (%)		0.71%	0.89%	0.83%	0.67%	0.76%	0.52%	0.62%
		Unsupplied energy (minutes)		19.5	13.3	8.0	7.1	13.3	6.4	9.0
	Asset & Project Management	Transmission System Plan Implementation Progress (%)		99%	101%	101%	99%	101%	97%	100%
		CapEx as % of Budget (%)		97%	99%	104%	112%	114%	97%	100%
		OM&A Program Accomplishment (composite index)		107	88	93	105	96	109	100
		Transmission Capital Accomplishment Index (TCAI) - (%)				101%	99%	80%	91%	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		7.7%	7.4%	7.9%	8.3%	7.6%	7.8%	7.9%
		OM&A per Gross Fixed Asset Value (%)		2.3%	1.9%	2.1%	2.0%	2.2%	2.2%	1.9%
		Line Clearing Cost per kilometer ($)		$2,797	$3,817	$3,368	$2,211	$2,140	$2,210	$2,784
		Brush Control Cost per Hectare ($)		$1,539	$1,924	$1,538	$1,807	$2,003	$1,916	$1,628
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments (CIAs)		100%	100%	100%	100%	100%	No CIAs in 2023	100%
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met (%)		100%	100%	100%	95%	100%	100%	100%
		End-of-Life Right-Sizing Assessment Expectation		Met	Met	Met	Met	Met	Met	Met
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.12	0.20	0.28	0.27	0.23	0.21	N/A
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.53	1.52	1.50	1.40	1.37	1.48	N/A
		Profitability: Regulatory Return on Equity	Deemed	9.00%	N/A	8.52%	8.52%	8.52%	9.36%	N/A
			Approved	11.08%	9.53%	9.29%	9.30%	9.92%	10.80%	N/A

Fiscal 2024 Hydro One Networks Electricity Transmitter Scorecard, Management Discussion and Analysis ("Scorecard MD&A")

Hydro One Networks Electricity Transmitter 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 2024 One Transmission Scorecard is attached, and the discussion is set out below.

Service Quality

- **Customer Delivery Point Performance - Standard Outliers as Percent of Total Delivery Points**

  The Customer Delivery Point Performance is a service quality metric that is measured as the number of standard performance outliers (using standards set by the OEB) as a percentage of the total number of Hydro One delivery points. Customer Delivery Point Performance Standards (CDPPS) were established by the OEB to ensure acceptable transmission reliability experienced at transmission customer delivery points. The group outlier standard defines a delivery point as an outlier if its performance is over the thresholds based on its station load size. The individual outlier standard defines a delivery point as an outlier if its recent two-year's performance is worse than its historical performance. The percentage of outliers to total number of delivery points is measured annually.

  The Standard Outliers as a Percent of Total Delivery Points was 13.6% in 2024, which was higher than the target of 10.8%. The GTA

[1] EB-2021-0110, Settlement Agreement, Appendix A

flooding event impacting Manby TS in July of 2024 was a major contributor to the overall result.

Customer Satisfaction

- **Overall Customer Satisfaction**

  This measure reflects the overall satisfaction levels among customers within the three major transmission-connected segments (Transmission End Users, Local Distribution Companies (LDCs) and Transmission-Connected Generators).

  The Overall Customer Satisfaction was 85% in 2024, which was lower than the target of 88%. The result was attributable to an increase in major weather events causing system outages.

- **Satisfaction With Outage Planning Procedures**

  This measure reflects the satisfaction with planned outage management among customers within the three major transmission-connected segments (Transmission End Users, LDCs and Transmission-Connected Generators).

  Satisfaction with Outage Planning Procedures was 88% in 2024, which was better than the target of 85%.

Safety

- **Recordable Injury # of recordable injuries/illnesses per 200,000 hours worked**

  The number of recordable injuries/illnesses per 200,000 hours worked measures the work-related injuries or illnesses per 200,000 hours worked which result in: restricted work, lost time, loss of consciousness, medical attention beyond first aid, death, or any other significant work-related injury or illness diagnosed by a physician or other healthcare professional and are confirmed by a Hydro One Occupational Health Nurse. This measure only applies to employees of Hydro One and excludes contractors and the general public.

  The Recordable Injury rate was 0.5 in 2024, which was better than the target of 0.9.

System Reliability

- **T-SAIFI-S (Average Number of Sustained interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Sustained is measured as the total number of unplanned sustained interruptions (1 minute or longer) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Sustained was 0.52 in 2024, which was better than the target of 0.55.

- **T-SAIFI-M (Average Number of Momentary interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Momentary is measured as the total number of unplanned momentary interruptions (less than 1 minute) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Momentary was 0.44 in 2024, which was higher than the target of 0.42. This result is mainly due to an increase in inclement weather when compared to the previous 5-year average.

- **T-SAIDI (Average minutes of interruptions per Delivery Point)**

  Transmission System Average Interruption Duration Index is measured as the total number of minutes of unplanned interruptions that customers experienced per Delivery Point in a year. The measure is presented as interruption minutes per delivery point per year. Only sustained (1 minute and longer as per the Canadian Electricity Association (CEA) industry standard) interruptions contribute to this measure. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

The Transmission System Average Interruption Duration Index was 23.7 in 2024, which was better than the target of 31.9.

- **System Unavailability (%)**

  System Unavailability measures the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. While equipment unavailability doesn't necessarily lead to interruptions due to redundancy on Hydro One's transmission system, it is a leading indicator of future reliability erosion.

  Major station equipment includes Transmission lines, High voltage cables, Breakers, Transformers, Shunt capacitor banks, Shunt reactors, Series capacitor banks and Static VAR Compensators. This metric does not take into consideration the subordinate outages of healthy transmission equipment being removed out of service because of the outage of some other equipment.

  The System Unavailability was 0.50% in 2024, which was better than the target of 0.61%.

- **Unsupplied Energy (minutes)**

  Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to allow comparison with the performance of different sized utilities.

  The Unsupplied Energy was 8.2 minutes in 2024, which was better than the target of 8.8 minutes.

Asset and Project Management

- **Transmission System Plan Implementation Progress (%)**

  The Transmission System Plan Implementation Progress is measured as the total actual in-year sustainment, development, and operating expenditures for in-service additions over the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance.

  In-service capital additions are tracked and reported in a manner consistent with the regulatory requirements of the transmission business and reported as a percentage value relative to the transmission plan.

  The Transmission System Plan Implementation Progress was 95% in 2024, which was lower than the target of 100%. The result is primarily due to timing shifts of major capital projects.

- **CapEx as % of Budget**

  Capex as a percentage of budget is measured as the total actual capital expenditures over the total amount budgeted (planned) capital expenditures in a year. This measure reflects the progress of Hydro One's capital expenditures towards the approved plan.

  The CapEx as a % of Budget was 114% in 2024, which was higher than the target of 100%. The result is primarily due to the accelerated timing of expenditures on major capital projects and third-party externally driven work.

- **Operations, Maintenance and Administration (OM&A) Program Accomplishment (composite index)**

  The Transmission OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) Forestry Line Clearing; 2) Brush Control; 3) PCB Testing and Retro fill; and Station Preventive Maintenance programs which include 4) Power Equipment, 5) Ancillary Equipment, 6) Protection and Control, 7) Telecom and 8) Infrastructure.

  The Transmission OM&A Program Accomplishment composite index was 102% in 2024, which was better than the target of 100%.

- **Transmission Capital Accomplishment Index (TCAI) - (%)**

  The TCAI compares the weighted actual in-year accomplishment for significant transmission system renewal capital investments against the weighted budget. The investments covered by this metric represent the major assets associated with station centric and lines refurbishment projects being transformers, circuit breakers, protections and circuit kilometers of transmission line, as well as five programs including insulator replacement, wood pole replacement, shield wire replacement, tower foundations and steel structure coating.

  The Transmission Capital Accomplishment Index was 95% in 2024, which was lower than the target of 100%. This result is due to outage challenges impacting insulator replacement, as well as Circuit Breaker and Transmission Line Refurbishment project units due to timing shifts.

Cost Control

- **Total OM&A and Capital per Gross Fixed Asset Value (%)**

  The Total OM&A and Capital per Gross Fixed Asset Value is measured as the total capital and OM&A spend over the total gross book value of in-service assets. This measure demonstrates transmission cost effectiveness.

  The Total OM&A and Capital per Gross Fixed Asset Value was 8.49% in 2024, which was higher than the target of 8.0%. This result is due to the accelerated timing of capital expenditures and a lower gross fixed asset base due to timing shifts of major capital projects forecast to be completed in future years.

- **OM&A per Gross Fixed Asset Value (%)**

  OM&A per Gross Fixed Asset Value is measured as the total OM&A over the gross book value of fixed assets. The measure demonstrates transmission cost effectiveness.

  The OM&A per Gross Fixed Asset Value was 2.0% in 2024, which was higher than the target of 1.8%. This result is due to higher OM&A and a lower gross fixed asset base, due to timing shifts of major capital projects which are forecast to be completed in future years.

- **Line Clearing Cost per Kilometer ($/km)**

  The Line Clearing Cost per Kilometer is measured as the total line clearing costs over the total number of kilometers of transmission line. This measure shows the cost associated with line clearing activities completed in the year, per kilometer of line.

  The Line Clearing Cost per Kilometer was $2,426 in 2024, which was better than the target of $2,854.

- **Brush Control Cost per Hectare ($/Ha)**

  The Brush Control Cost per Hectare is measured as the total cost of brush control completed in the year, per hectare of brush.

  The Brush Control Cost per Hectare was $2,402 in 2024, which was higher than the target of $1,669. This result is due to the elimination of herbicide use in some areas, and increased costs related to helicopter requirements in remote areas.

Customer Impact Assessment on Renewable Generation

- **% On-time completion of Customer Impact Assessments on Renewable Generation**

  For Transmission-connected generators, Hydro One is obligated under the Transmission System Code to complete a customer impact assessment (CIA) for renewables within 150 days. The % of on-time completion of renewables CIAs is measured as the total number of renewables CIAs completed within the required timeline over the total number of renewables CIAs completed in the year.

  No Customer Impact Assessments on Renewable Generation were reported in 2024.

Regional Infrastructure Planning & Long-Term Energy Plan (LTEP) Right-Sizing

- **Regional Infrastructure Planning progress - Deliverables met (%)**

  Regional Infrastructure Planning Progress – Deliverables met measures progress in meeting the deliverables of the regional infrastructure

planning process, including meeting the Transmission System Code ("TSC") prescribed timelines and delivering the required products. The number of deliverables will vary in a given year. Deliverables include plans, reports and Local Distribution Companies (LDC) status update letters. Deliverables met is measured as the number of correct deliverables that meet the TSC prescribed timelines over the total number of deliverables.

The Regional Infrastructure Planning Progress – Deliverables Met was 100% in 2024, which met the target of 100%.

- **End-of-Life Right-Sizing Assessment Expectation**

  This qualitative measure gauges Hydro One's performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing the replacement of end-of-life equipment to facilitate future growth are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year. Measure Calculation: N/A as this is a qualitative measure – either Met or Not Met

  The End-of-Life Right Sizing Assessment Expectation was met in 2024.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  Liquidity: Current Ratio measures the ratio of 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 will become due within the year.

  The Liquidity: Current Ratio was 0.21 in 2024.

- **Leverage: Total Debt to Equity Ratio**

  The Total Debt to Equity Ratio is measured as the total short-term and long-term debt over the total equity. This measure reflects Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60% to 40% debt-to-equity structure (a ratio of 1.5).

The Leverage: Total Debt to Equity Ratio was 1.65 in 2024.

- **Profitability: Regulatory Return on Equity**

  Achieved Regulatory Return on Equity (ROE) measures the OEB-approved ROE that is embedded in the transmitter's base rates. ROE is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB.

  The Profitability: Regulated Return on Equity was 10.96% in 2024.

Note to Readers of Fiscal 2024 Scorecard MD&A

The information provided by Transmission Business on their future performance (or what can be construed as forward-looking information) may be subject to several 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 service quality metrics, including their purposes and frequency of measurement; the development of the transmission system and the progress of the implementation of the transmission system plan; the timing for System Access and System Renewal projects and other system renewal projects; performance measurements regarding end-of-life right-sizing equipment assessment opportunities; financial measurements and their implications; 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.

Fiscal 2025 Hydro One Networks Electricity Transmitter Scorecard, Management Discussion and Analysis ("Scorecard MD&A")

Hydro One Networks Electricity Transmitter 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 2025 Hydro One Transmission Scorecard discussion is set out below.

Service Quality

- **Customer Delivery Point Performance - Standard Outliers as Percent of Total Delivery Points**

  The Customer Delivery Point Performance is a service quality metric that is measured as the number of standard performance outliers (using standards set by the OEB) as a percentage of the total number of Hydro One delivery points. Customer Delivery Point Performance Standards (CDPPS) were established by the OEB to ensure acceptable transmission reliability experienced at transmission customer delivery points. The group outlier standard defines a delivery point as an outlier if its performance is over the thresholds based on its station load size. The individual outlier standard defines a delivery point as an outlier if its recent two year's performance is worse than its historical performance. The percentage of outliers to total number of delivery points is measured annually.

[1] EB-2021-0110, Settlement Agreement, Appendix A

The Standard Outliers as a Percent of Total Delivery Points was 9.3% in 2025, which met the target of 10.6%.Customer Satisfaction

- **Overall Customer Satisfaction**

  This measure reflects the overall satisfaction levels among customers within the three major transmission-connected segments (Transmission End Users, Local Distribution Companies (LDCs) and Transmission-Connected Generators).

  The Overall Customer Satisfaction was 79% in 2025, which did not meet the target of 88%. The result was primarily attributed to major weather events.

- **Satisfaction With Outage Planning Procedures**

  This measure reflects the satisfaction with planned outage management among customers within the three major transmission-connected segments (Transmission End Users, LDCs and Transmission-Connected Generators).

  Satisfaction with Outage Planning Procedures was 84% in 2025, which did not meet the target of 85%. The result was primarily due to workload growth driven by an increase in development activity (new lines and stations) that raised the complexity of prioritization of outage planning and the potential for greater customer impact.

Safety

- **Recordable Injury # of recordable injuries/illnesses per 200,000 hours worked**

  The number of recordable injuries/illnesses per 200,000 hours worked measures the work-related injuries or illnesses per 200,000 hours worked which result in: restricted work, lost time, loss of consciousness, medical attention beyond first aid, death, or any other significant work-related injury or illness diagnosed by a physician or other healthcare professional and are confirmed by a Hydro One Occupational Health Nurse. This measure only applies to employees of Hydro One and excludes contractors and the general public.

  The Recordable Injury rate was 0.68 in 2025, which met the target of 0.9.

System Reliability

- **T-SAIFI-S (Average Number of Sustained interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Sustained is measured as the total number of unplanned sustained interruptions (1 minute or longer) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Sustained was 0.46 in 2025, which met the target of 0.54.

- **T-SAIFI-M (Average Number of Momentary interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Momentary is measured as the total number of unplanned momentary interruptions (less than 1 minute) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Momentary was 0.26 in 2025, which met the target of 0.41.

- **T-SAIDI (Average minutes of interruptions per Delivery Point)**

  Transmission System Average Interruption Duration Index is measured as the total number of minutes of unplanned interruptions that customers experienced per Delivery Point in a year. The measure is presented as interruption minutes per delivery point per year. Only sustained (1 minute and longer as per the Canadian Electricity Association (CEA) industry standard) interruptions contribute to this measure. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Duration Index was 18.5 in 2025, which met the target of 31.3.

- **System Unavailability (%)**

  System Unavailability measures the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. While equipment unavailability doesn't necessarily lead to interruptions due to redundancy on Hydro One's transmission system, it is a leading indicator of future reliability erosion.

  Major station equipment includes transmission lines, high voltage cables, breakers, transformers, shunt capacitor banks, shunt reactors, series capacitor banks and static VAR compensators. This metric does not take into consideration the subordinate outages of healthy transmission equipment being removed out of service because of the outage of some other equipment.

  The System Unavailability was 0.63% in 2025, which did not meet the target of 0.60%. This result was primarily due to large contributions to this metric by transformers awaiting replacement, capacitors and capacitor breakers awaiting repairs and repair of switches.

- **Unsupplied Energy (minutes)**

  Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to allow comparison with the performance of different sized utilities.

  The Unsupplied Energy was 5.7 minutes in 2025, which met the target of 8.6 minutes.

Asset and Project Management

- **Transmission System Plan Implementation Progress (%)**

  The Transmission System Plan Implementation Progress is measured as the total actual in-year sustainment, development, and operating expenditures for in-service additions over the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance.

  In-service capital additions are tracked and reported in a manner consistent with the regulatory requirements of the transmission business and reported as a percentage value relative to the transmission plan.

  The Transmission System Plan Implementation Progress was 91% in 2025, which did not meet the target of 100%. The result is primarily driven by the timing of major project completions and changes in the nature of work undertaken during the current rate period.

- **CapEx as % of OEB Approved Plan**

  Capex as a percentage of budget is measured as the total actual capital expenditures over the total amount budgeted (planned) capital expenditures in a year. This measure reflects the progress of Hydro One's capital expenditures towards the approved plan.

  The CapEx as a % of Budget was 109% in 2025, which met the target of 100% with increased levels of mandatory system development work driven by external requirements, customer requests, and growth.

- **Operations, Maintenance and Administration (OM&A) Program Accomplishment (composite index)**

  The Transmission OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) forestry line clearing; 2) brush control; 3) PCB testing and retro fill; and station preventive maintenance programs which include 4) power equipment, 5) ancillary equipment, 6) protection and control, 7) telecom and 8) infrastructure.

  The Transmission OM&A Program Accomplishment composite index was 97 in 2025, which did not meet the target of 100. The results

are primarily due to lower work program expenditures in the PCB Testing and Retrofill programs primarily attributable to lower number of units accomplished with limited candidate availability.

- **Transmission Capital Accomplishment Index (TCAI) - (%)**

  The TCAI compares the weighted actual in-year accomplishment for significant transmission system renewal capital investments against the weighted budget. The investments covered by this metric represent the major assets associated with station centric and lines refurbishment projects being transformers, circuit breakers, protections and circuit kilometers of transmission line, as well as five programs including insulator replacement, wood pole replacement, shield wire replacement, tower foundations and steel structure coating.

  The Transmission Capital Accomplishment Index was 112% in 2025, which met the target of 100%.

COST CONTROL

- **Total OM&A and Capital per Gross Fixed Asset Value (%)**

  The Total OM&A and Capital per Gross Fixed Asset Value is measured as the total capital and OM&A spend over the total gross book value of in-service assets. This measure demonstrates transmission cost effectiveness.

  The Total OM&A and Capital per Gross Fixed Asset Value was 7.6% in 2025, which did not meet the target of 7.0%.

- **OM&A per Gross Fixed Asset Value (%)**

  OM&A per Gross Fixed Asset Value is measured as the total OM&A over the gross book value of fixed assets. The measure demonstrates transmission cost effectiveness.

  The OM&A per Gross Fixed Asset Value was 1.8% in 2025, which met the target of 1.8%.

- **Line Clearing Cost per Kilometer ($/km)**

  The Line Clearing Cost per Kilometer is measured as the total line clearing costs over the total number of kilometers of transmission line. This measure shows the cost associated with line clearing activities completed in the year, per kilometer of line.

  The Line Clearing Cost per Kilometer was $2,896 in 2025, which met the target of $2,925.

- **Brush Control Cost per Hectare ($/Ha)**

  The Brush Control Cost per Hectare is measured as the total cost of brush control completed in the year, per hectare of brush.

  The Brush Control Cost per Hectare was $2,678 in 2025, which did not meet the target of $1,711. The result is primarily attributable to project requirement changes requiring inclusion of urban and helicopter support, higher fleet and labour costs along with an increase in temporary work headquarter costs.

Customer Impact Assessment on Renewable Generation

- **% On-time completion of Customer Impact Assessments on Renewable Generation**

  For new Transmission-connected renewable generation projects, Hydro One was required under the O. Reg. 326/09 to complete a customer impact assessment (CIA) for renewables within 150 days. The % of on-time completion of renewables CIAs is measured as the total number of renewables CIAs completed within the required timeline over the total number of renewables CIAs completed in the year. This regulation was rescinded in 2021.

  In 2025, no requests for transmission-connected renewable generation were received. As a result, no Customer Impact Assessments were required or conducted. Accordingly, performance for this metric is reported as “No CIAs Required in 2025”.

Regional Infrastructure Planning & Long-Term Energy Plan (LTEP) Right-Sizing

- **Regional Infrastructure Planning progress - Deliverables Met (%)**

  Regional Infrastructure Planning Progress – Deliverables Met measures progress in meeting the deliverables of the regional infrastructure planning process, including meeting the Transmission System Code ("TSC") prescribed timelines and delivering the required products. The number of deliverables will vary in a given year. Deliverables include plans, reports and Local Distribution Companies (LDC) status update letters. Deliverables Met is measured as the number of correct deliverables that meet the TSC prescribed timelines over the total number of deliverables.

  The Regional Infrastructure Planning Progress – Deliverables was 100%, which met the target in 2025.

- **End-of-Life Right-Sizing Assessment Expectation**

  This qualitative measure gauges Hydro One's performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing the replacement of end-of-life equipment to facilitate future growth are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year. Measure Calculation: N/A as this is a qualitative measure – either Met or Not Met

  The End-of-Life Right Sizing Assessment Expectation met the target in 2025.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  Liquidity: Current Ratio measures the ratio of 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 will become due within the year.

  The Liquidity: Current Ratio was 0.25 in 2025.

- **Leverage: Total Debt to Equity Ratio**

  The Total Debt to Equity Ratio is measured as the total short-term and long-term debt over the total equity. This measure reflects Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60% to 40% debt-to-equity structure (a ratio of 1.5).

  The Leverage: Total Debt to Equity Ratio was 1.72 in 2025.

- **Profitability: Regulatory Return on Equity**

  Achieved Regulatory Return on Equity (ROE) measures the return earned on the equity component that is embedded in the transmitter's base rates. Hydro One's Transmission Business deemed regulatory return on equity (ROE) for 2025 is 9.36%, as approved by the OEB.

  The Profitability: Regulated Return on Equity was 12.72% in 2025. The 2025 achieved ROE was higher than deemed primarily due to higher demand driven by external factors including weather-related variability as compared to the load forecast embedded in rates, and other factors including timing of in-service additions.

Note to Readers of Fiscal 2025 Scorecard MD&A

The information provided by transmitters on their future performance (or what can be construed as forward-looking information) may be subject to several 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 financial measurements and their implications, 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 Electricity Transmitter Scorecard

Performance Outcomes	Performance Categories	Measures		2020	2021	2022	2023	2024	2025	JRAP Target 2025
Customer Focus	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs (%)		11.4%	8.3%	9.3%	10.9%	13.6%	9.3%	10.6%
	Customer Satisfaction	Overall Customer Satisfaction (%)		83%	92%	88%	88%	85%	79%	88%
		Satisfaction with Outage Planning Procedures (%)		71%	82%	78%	72%	88%	84%	85%
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)		0.87	0.74	0.62	0.56	0.55	0.68	0.90
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)		0.50	0.49	0.64	0.54	0.52	0.46	0.54
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)		0.40	0.42	0.43	0.46	0.44	0.26	0.41
		T-SAIDI (Ave. minutes of interruptions per Deliver Point)		61.3	21.0	61.0	25.9	23.7	18.5	31.3
		System Unavailability (%)		0.83%	0.67%	0.76%	0.52%	0.50%	0.63%	0.60%
		Unsupplied energy (minutes)		8.0	7.1	13.3	6.4	8.2	5.7	8.6
	Asset & Project Management	Transmission System Plan Implementation Progress (%)		101%	99%	101%	97%	95%	91%	100%
		CapEx as % of Budget (%)		104%	112%	114%	97%	114%	109%	100%
		OM&A Program Accomplishment (composite index)		93%	105%	96%	109%	102%	97%	100%
		Transmission Capital Accomplishment Index (%)		101%	99%	80%	91%	95%	112%	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		7.9%	8.3%	7.6%	8.6%	8.5%	7.6%	7.0%
		OM&A per Gross Fixed Asset Value (%)		2.1%	2.0%	2.2%	2.4%	2.0%	1.8%	1.8%
		Line Clearing Cost per kilometer ($/km)		$3,368	$2,211	$2,140	$2,210	$2,426	$2,896	$2,925
		Brush Control Cost per Hectare ($/Ha)		$1,538	$1,807	$2,003	$1,916	$2,402	$2,678	$1,711
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments (CIAs)		100%	100%	100%	None requested	None requested	None requested	100%
	Regional Infrastructure Planning & Long-Term Energy Plan Right-Sizing	Regional Infrastructure Planning progress - Deliverables met (%)		100%	95%	100%	100%	100%	100%	100%
		End-of-Life Right-Sizing Assessment Expectation		Met	Met	Met	Met	Met	Met	Met
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.28	0.27	0.23	0.21	0.21	0.25	N/A
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.50	1.40	1.37	1.48	1.65	1.72	N/A
		Profitability: Regulatory Return on Equity	Deemed	8.52%	8.52%	8.52%	9.36%	9.36%	9.36%	N/A
			Achieved RROE %	9.29%	9.30%	9.92%	10.80%	10.96%	12.72%	N/A

SECTION 2.5 – ATTACHMENT 4 – HYDRO ONE - APPENDIX 2-G – SERVICE RELIABILITY AND QUALITY INDICATORS

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SECTION 2.6 – TSP – OTHER CAPITAL PLANNING FACTORS AND CONSIDERATIONS

2.6.1 INTRODUCTION

Sections 2.2 through 2.4 of the Transmission System Plan (TSP) outline key planning considerations related to transmission system needs, asset condition, reliability, and benchmarking results.

This section describes the additional capital planning factors and considerations that informed the development of the TSP and shaped the proposed plan.

These considerations include customer needs and preferences, regional planning information, bulk planning information, statutory and regulatory obligations, industry and reliability standards, third-party requirements, and other external planning considerations.[1] Hydro One incorporates these factors within its planning framework through the development and screening of candidate investments. Where applicable, these inputs inform the scope, timing, and prioritization of investments, alongside system need, asset condition, risk, and cost considerations.

The specific factors discussed in this Exhibit are customer engagement and additional planning and regulatory considerations that have influenced the development of the TSP, including:

- regional planning needs;
- bulk system planning;
- third-party directed investments;
- maintaining a reliable and resilient grid;
- environmental stewardship; and
- other regulatory requirements and considerations.

[1] Ontario Ministry of Energy and Mines, Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025) – pp. 67–79, Chapter 3.

2.6.2 CUSTOMER ENGAGEMENT

Hydro One undertakes a range of customer engagement activities to inform its capital planning processes, including a formal customer engagement survey. The specifics of the customer engagement process are described in SPF Section 1.6. These engagement activities provide insight into the outcomes customers' value as well as their preferences regarding the level, mix, and pacing of transmission investments. This section explains how customer engagement results were reflected in the development of the TSP.

Customer engagement was undertaken in two stages. The initial stage occurred in mid-to-late 2024. It was conducted to identify customer priorities and outcome preferences in advance of detailed planning. The second stage, in late 2025, sought customer feedback on Hydro One's draft investment plans, including their views on specific investment tradeoffs. This sequencing allowed customer input to inform the development of candidate investments and subsequent refinement of the proposed plans.

The results from the initial engagement were reviewed in late 2024 through cross-functional planning discussions within Hydro One. They were used to inform the early development and screening of potential transmission investments. Customer-identified priorities were assessed alongside system needs, asset condition, risk, and cost considerations. This resulted in balanced and evidence-based planning decisions.

The second engagement stage in the fall of 2025 provided customers with an opportunity to comment on proposed investments and associated tradeoffs, including those related to transmission investments and shared services. Transmission customers and other local distribution companies were specifically encouraged to provide input.

Feedback from the second stage was considered in finalizing the proposed TSP. Throughout the development of the TSP, customer-identified priorities were tracked and revisited at key planning milestones. Consideration was given to the scope, timing, and funding status of investments aligned with those priorities, and these considerations informed internal management discussions.

The final TSP demonstrates how customer engagement informed capital planning decisions, balancing customer preferences with system needs, reliability, safety, performance requirements, and the management of transmission rates.

Additional information on how the TSP reflects the pacing and types of investments supported by customers through the engagement process, as well as ongoing customer coordination and collaboration, is provided in TSP Section 2.8.

SPF Section 1.7 and TSP Section 2.7 provide further information on how customer input was integrated into Hydro One's broader capital planning framework and how the proposed TSP supports customer-valued outcomes.

2.6.3 ADDITIONAL PLANNING AND REGULATORY CONSIDERATIONS

2.6.3.1 REGIONAL PLANNING NEEDS

As discussed in SPF Section 1.2, regional planning addresses supply and reliability needs at the regional and local level, including the facilities that connect and deliver power to groups of load stations within an area or region.

Regional planning generally considers the 115 kV and 230 kV portions of the power system that supply various parts of the province. At some system boundaries, regional planning may interface with bulk system planning and distribution system planning. This can affect the alternatives considered to address specific local or regional needs.

The TSP investments vary from station expansions and new transformer stations to new transmission lines and uprates of existing circuits. Many projects are linked to enabling load growth and maintaining reliability at the regional level.

Hydro One considers a regional planning project to be non-discretionary in nature where Hydro One is identified, expressly or implicitly, as the lead transmitter in the region and is expected to undertake a recommended transmission solution and/or obligated to implement a recommended solution pursuant to its responsibilities under the Transmission System Code (TSC).

Given the regional nature of these investments, the costs are recoverable through incremental revenue from the appropriate rate pool. A portion of the capital expenditures is recoverable from customers pursuant to Hydro One's Transmission Connection Procedure in accordance with the TSC. Customer capital contributions may not be required when project costs are fully recovered through incremental revenue.

Further details on these investments can be found in SPF Section 1.2, TSP Section 2.8, and the associated System Access, System Service, and System Renewal investment summary documents found in TSP Section 2.12.

2.6.3.2 BULK SYSTEM PLANNING

Hydro One considers bulk system plans issued by the Independent Electricity System Operator (IESO) as part of the overall transmission planning context. These bulk system plans provide information on broader system needs and long-term network development across all regions.

Bulk system planning is distinct from the OEB's regional planning framework. Regional planning addresses local and regional electricity needs through the OEB-governed regional planning process. Bulk planning reflects broader system-level planning led by the IESO with input from Hydro One.

Where IESO bulk system plans recommend solutions that give rise to mandatory investments under Hydro One's planning framework, these investments are incorporated into the capital plan and reflected in the relevant investment summary documents found in TSP Section 2.12.

Hydro One Transmission used the best information available to develop the capital expenditure and in-service addition (ISA) forecasts. In doing so, Hydro One has considered recent IESO bulk-planning developments, including the South and Central Bulk Plan and ongoing bulk-planning work for North of Sudbury and East Ontario, as part of the broader context for its long-term transmission planning.

The IESO, through its ongoing planning engagements, continues to assess needs across the province. Hydro One anticipates that the IESO will publish at least five Bulk System Studies and 12 Integrated Regional Resource Plans in 2026 and 2027 during the proceeding for this Application, with additional expected during the planning period. These publications may identify further mandatory investments not currently reflected in the investment plan.

Ongoing Regional Planning and ongoing Bulk System Planning processes may give rise to incremental investment needs that have not been reflected in Hydro One's investment plan as filed in this Application. Where Hydro One is obligated to address incremental investment needs during the 2028-2032 period, including where the investment is the subject of a formal Order in Council and/or Ministerial Directive issued during the hearing of this Application, or as a result of the IESO issuing a Bulk Planning or Regional Planning report during the hearing of this Application that includes a recommended investment that Hydro One is expected to implement, Hydro One plans to file an update to its investment plan reflecting the incremental investment need during the hearing of this Application. Where such incremental investment needs arise after the close of the discovery phase of the proceeding, and which are not reflected in the Application through pre-filed or updated investment planning evidence, Hydro One intends to record the impact of such investments in the Externally Driven Transmission Projects Variance Account, as discussed in Exhibit G-01-03 section 3.1.

2.6.3.3 THIRD-PARTY DIRECTED INVESTMENTS

Pursuant to its statutory and regulatory obligations under the *Electricity Transmission Licence, Transmission System Code*, the *Public Service Works on Highways Act*, *1990,* and other applicable instruments, Hydro One is required to connect customers' facilities to its transmission system upon request; relocate its assets upon request from municipal and provincial governments and agencies to support transit expansion; undertake investments necessary to expand or reinforce the Ontario transmission system consistent with IESO directions; and, where applicable, advance transmission investments arising from provincial energy policy initiatives, including projects identified as priority transmission projects through an Order in Council. Further information regarding how

Hydro One's capital plan aligns with provincial energy policy initiatives, including those identified in the Integrated Energy Plan (IEP) as priority transmission projects, is provided in SPF Section 1.2, Attachment 1.

As a result, the TSP includes a number of investments required to satisfy Hydro One's statutory and regulatory obligations, customer requirements, government-directed initiatives, and broader energy policy initiatives. These investments include the following:

- Load or generator customer connections.
- Transmission facilities relocations.
- System expansion or reinforcement.

Further detail on these investments can be found in TSP Section 2.8 and the associated System Access, System Service, and System Renewal investment summary documents found in TSP Section 2.12.

2.6.3.4 MAINTAINING A RELIABLE AND RESILIENT GRID

Hydro One regularly reviews and updates its engineering and design standards to ensure new and renewed assets are designed to be reliable and resilient over their expected service lives. Industry design standards for transmission assets have been updated to require consideration of future climate stressors, including higher ambient temperatures, changing precipitation patterns, flood hazards, icing, wind loading, and wildfire risk. These updates are aligned with applicable mandatory standards and best practices established by the Canadian Standards Association (CSA), the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the International Electrotechnical Commission (IEC), ensuring that assets are designed, sited, and maintained for long-term resilience.

Examples of these design and engineering updates, reflected in capital planning decisions and investments, include higher temperature assumptions for transmission equipment ratings to safely meet growing peak demand during extreme heat events; hardened transmission line designs that reflect more severe weather and loading conditions over asset lives of up to 100 years; the development and standardization of mobile substations

to support faster service restoration following major disruptions; and enhanced consideration of flood risk and stormwater management at higher-risk stations.

2.6.3.5 ENVIRONMENTAL STEWARDSHIP

Exhibit A-02-04, section 2.13 describes Hydro One's settlement commitment to include, in future operational and capital investment plans, discussion of how proposed spending supports the achievement of Hydro One's climate change policy commitments by 2030 and 2050.[2] In the context of the TSP, this commitment is addressed by explaining how climate-related considerations are reflected within established transmission planning, engineering, asset management, vegetation management, and emergency preparedness practices.

As described in Section 2.6.3.4, Maintaining a Reliable and Resilient Grid section, those practices are primarily intended to maintain a reliable and resilient transmission system. For the TSP, climate change is considered as a factor that may affect asset performance, system resilience, restoration requirements, and operational risk. It is not treated as a standalone investment driver. The investments included in the TSP are primarily driven by reliability, safety, asset condition, compliance, customer and system needs, and operational risk. Where applicable, those investments and related practices also support climate adaptation and resilience by helping the transmission system withstand and recover from more severe weather conditions.

Hydro One also distinguishes climate adaptation and resilience from greenhouse gas mitigation. In the TSP, greenhouse gas mitigation is reflected primarily through operational and maintenance practices, such as SF_6 leak reduction and the management of gas-insulated equipment. These activities support Hydro One's broader climate change policy commitments, but they are not the primary basis for the TSP.

[2] EB-2021-0110 - Settlement Proposal, October 24, 2022

2.6.3.6 OTHER REGULATORY REQUIREMENTS AND CONSIDERATIONS

The planning, design, operation, and maintenance of Hydro One's transmission system are governed by a variety of standards. These include safety standards, reliability standards, environmental and noise mitigation standards, and cybersecurity standards.

Meeting these standards is a mandatory requirement. It is also key to ensuring that Hydro One's transmission system continues to operate in a safe and reliable manner. Standards that are applicable to the planning, design, operation, and maintenance of Hydro One's transmission system are constantly changing and becoming more onerous.

As a result, Hydro One's proposed investment plan includes a variety of investments required to ensure Hydro One's continued compliance with the most recent standards. Further details on these investments can be found in TSP Section 2.8 and the associated System Renewal investment summary documents found in TSP Section 2.12.

SECTION 2.7 – TSP – INVESTMENT PLANNING PROCESS

2.7.1 INTRODUCTION

Section 1.7 of the System Plan Framework (SPF) describes Hydro One's integrated planning framework, known as the system planning process, which is comprised of strategy and context, asset management and investment planning processes that create a comprehensive approach for managing the utility's asset base and prudently identifying and prioritizing investments. The output is a detailed, multi-year investment plan (consisting of the Transmission, Distribution and General Plant System Plans) that prudently addresses system and asset needs in alignment with Hydro One's strategic priorities and service obligations.

This planning framework achieves outcomes that are consistent with the OEB's RRF and that reflect customer priorities (including priorities communicated through customer engagement), as described in detail in SPF Sections 1.6 and 1.7, respectively.

This section highlights and supplements SPF Section 1.7 by discussing the processes used to identify, select, prioritize, optimize and pace the Transmission System Plan (TSP) investments.

- Section 2.7.2 provides an overview of the transmission system planning process.
- Section 2.7.3 discusses elements of the asset management process as applied to transmission assets.
- Section 2.7.4 discusses the investment planning process that underpinned the TSP.

2.7.2 TRANSMISSION SYSTEM PLANNING PROCESS

Hydro One's system planning process is a robust and value-driven approach that assesses system and asset-related risks and addresses those risks through investments that align with the company's strategic priorities, as well as customer needs and preferences.

The system planning process enables a consistent understanding of risk across the organization and, in this TSP, in relation to the assets that form the backbone of the province's electricity system. Using this process, Hydro One identifies investments that will cost-effectively mitigate risks over the planning period.

As stated in the Transmission Investment Summary Documents (see TSP Section 2.12), each investment has an identified primary trigger and explicit consideration of the RRF outcomes: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Hydro One's planning is influenced by customer needs, preferences, and priorities. Hydro One undertakes a range of activities to engage with customers consistently and proactively. The activities result in the company's increased understanding of customer needs and preferences which enables the planning and execution of investments aligned with customer values and preferred outcomes. Customer engagement is detailed in SPF Sections 1.6. It is also highlighted as part of Section 2.7.4 below.

2.7.3 ASSET MANAGEMENT PROCESS

Hydro One employs a lifecycle management approach which balances asset performance, costs, and associated risks during an asset's service life, as detailed in TSP Section 2.2. By monitoring the current state of its transmission assets and identifying current and future needs, Hydro One develops a set of candidate investments. These are then evaluated and prioritized via the investment planning process (discussed in Section 2.7.4 below).

2.7.3.1 CURRENT STATE ASSESSMENT

The investments proposed in this TSP are underpinned by a thorough understanding of the current state of the transmission system. This includes an evaluation of asset, customer, and overall system needs, along with other external factors that influence investments. These assessments are described below.

2.7.3.1.1 ASSET CONDITION NEEDS ASSESSMENT

Hydro One continuously assesses the transmission system to determine asset needs. While asset condition is the primary consideration in this assessment, Hydro One also considers asset criticality, utilization, and performance. Age is not the primary driver for any specific investment however demographics provide insight into long-term fleet level needs. Information on the assessment of major transmission asset types is provided in TSP Section 2.2 – Asset Information and Lifecycle Strategies.

Investments largely underpinned by asset condition data from ongoing asset assessments are found within the System Renewal category in TSP Section 2.12.

2.7.3.1.2 CUSTOMER NEEDS

Hydro One engages customers proactively and regularly through various mechanisms, including customer connection requests, ongoing engagement activities, meetings, and formal customer surveys. Understanding the needs of its diverse set of transmission system customers (consisting of generators, large industrial end-users, and Ontario's LDCs) is critical to Hydro One's business effectiveness.

In addition to broad customer preferences on priorities and trade-offs surveyed in Hydro One's two-phase customer engagement, described in SPF Section 1.6, specific customer needs in terms of connection to the system, as well as broader local, regional, and bulk growth requirements have driven various investments within the System Access and System Service category in TSP Section 2.12.

2.7.3.1.3 POWER SYSTEM NEEDS

The assessment of system needs drives investments to ensure the transmission system continues to deliver adequate and reliable supply to customers. In planning these investments, Hydro One ensures adequate capacity to supply customers and areas connected to its transmission system, mitigates against potential high-impact events to ensure safe and reliable operations in accordance with mandatory requirements, and provides for transmission facility needs identified from bulk system planning (discussed in

TSP Section 2.6) and regional planning (discussed in SPF Section 1.2 and TSP Section 2.6).

With respect to regional planning, Hydro One Transmission and HOSSM are the lead transmitters responsible for the development of needs assessments and regional infrastructure plans in 20 of the 21 planning regions. This work is conducted in conjunction with customers, the IESO, and LDCs.

Investments arising from Bulk System Planning and Regional Planning to address system needs are included in the System Service category in TSP Section 2.12.

2.7.3.1.4 EXTERNAL AND OTHER INFLUENCES

Hydro One uses information on industry best practices, trends and benchmarking to evaluate its performance against peer utilities. These studies and comparisons generate insight regarding Hydro One's operations relative to benchmark comparators, which can guide continuous improvement efforts and inform investment decision-making. A discussion of the studies related to the TSP is included in TSP Section 2.3.

2.7.3.2 INVESTMENT CANDIDATE DEVELOPMENT

After evaluating the current state of the transmission system and identifying asset, customer, and system needs, Hydro One develops a suite of investment candidates that are assessed and prioritized through the investment planning process.

2.7.4 INVESTMENT PLANNING PROCESS

The information and data collected through the asset management process establishes the basis for evaluating and prioritizing investments, and establishing the TSP. Through the investment planning process, investment candidates are assessed in terms of total risk mitigation, risk spend efficiency, and contribution to desired outcomes. They are calibrated to consistently assess relevant risks across the organization, as summarized below and detailed in SPF Section 1.7.

2.7.4.1 INVESTMENT CANDIDATE LIFECYCLE RISK ASSESSMENT

For each investment candidate, Hydro One assesses the amount of risk that is expected to be mitigated across three risk categories as applicable – safety, reliability, and environmental.

Each risk category features clear definitions and a consistent approach, providing for a proper assessment of the risk mitigated by each candidate investment. The assessment considers the probability and consequence of an event materializing, relying on historical data, condition information and experience to the extent possible. It also considers the risk mitigated by each candidate investment through the comparison of the risk profile pre and post investment.

Hydro One also uses a “flagging” process to supplement the three risk categories. Flags are used to account for special considerations and ensure stakeholder perspectives are included in the evaluation of investments. For example, these flags enable the consideration of compliance driven investments, as well as other considerations.

2.7.4.2 CALIBRATION

Once candidate investments have been risk assessed and flagged, candidate investments are further reviewed through facilitated discussions among investment owners. These discussions are known as “calibration sessions”. These sessions bring together stakeholders from across the organization to compare approaches and assumptions in scoring investments. This ensures that the risk assessment and scoring process have been applied consistently.

2.7.4.3 PRIORITIZATION AND OPTIMIZATION

The results from the risk assessments are translated into risk scores, based on total risk mitigation. These are used to generate an initial prioritization of investments. Risk scores are normalized by estimated investment cost and used to rank investments by risk mitigated per dollar, or “Risk Spend Efficiency” (RSE). The absolute value of the risk scores are reviewed, and any risks that are deemed unacceptable are reduced to an acceptable level through the inclusion of the necessary investments into the plan.

Once a prioritized list is determined based on RSE, challenge sessions are held among a broad set of stakeholders to: (i) review the integrated portfolio, (ii) evaluate and confirm non-risk parameters (e.g. strategic, productivity investments), (iii) assess and debate investments, and (iv) confirm trade-off decisions.

2.7.4.4 ENGAGEMENT

Following the development of the draft portfolio of investments, the draft plan is subject to two types of engagement to inform plan finalization.

Internally, an enterprise engagement process is undertaken to incorporate further execution considerations. Externally, the second phase of customer engagement is undertaken to further solicit customer feedback on investment decisions.

In addition to the draft plan (Scenario 2), Hydro One developed two other investment scenarios – a spend less plan (Scenario 1) and a spend more plan (Scenario 3) – which took into account customer needs and preferences from Phase I of customer engagement and were presented for customer feedback during Phase II of customer engagement.

2.7.4.4.1 ENTERPRISE ENGAGEMENT

Enterprise engagement ensures that the investment plan is properly reviewed and considered by the executing lines of business. This process incorporates operational and execution considerations, including resourcing, material availability, and updated cost estimates, schedules, and scope. This feedback was incorporated into the three investment plan scenarios noted above.

2.7.4.4.2 CUSTOMER ENGAGEMENT

To identify customer needs and preferences in preparation for its 2028 – 2032 investment planning process and this Application, Hydro One engaged Innovative Research Group (IRG) to develop and conduct a customer engagement study – see SPF Section 1.6.

Phase I of the IRG Study focused on customers' general needs and outcome preferences for the electricity system. Transmission customers generally valued reducing the number

and length of outages. With respect to trade-offs, a majority of transmission customers wanted Hydro One to make investments to maintain or increase the current level of reliability related to the transmission grid.

In Phase II of the IRG Study, three investment scenarios were presented to customers, representing trade-offs that Hydro One has within its investment plan. These scenarios considered the customer feedback collected in Phase I.

Scenario 1 (spend less) prioritizes lower rate impacts by deferring investments to a future rate period. Scenario 2 (draft plan) sought to keep pace with and/or improve asset condition while managing costs. Scenario 3 (spend more) allows Hydro One to investment more but long term risk is lower. Table 1 below summarizes the transmission-related investment scenarios presented to customers.

Table 1 - Transmission Investment Scenarios Presented to Customers During Phase II

Segment	Option	Scenario 1 – Slower Pace (Spend Less)	Scenario 2 – Draft Plan	Scenario 3 – Accelerated Pace (Spend More)
Transmission	• **Transmission Renewal**	Higher risk of equipment failure at transmission stations and for underground cables, driven by a slower pace of asset replacement and greater reliance on aging infrastructure.	Maintains the current level of transmission station and cable health by replacing the highest-risk assets and managing failure risk over time.	Improves the overall health of transmission stations and cable assets by accelerating replacements, reducing the likelihood of equipment failure.
	• **Transmission Stewardship**	Higher exposure to outages and severe-weather impacts due to reduced line replacements, structure reinforcement, and vegetation management.	Lowers the risk of equipment failure and severe weather through balanced investment in line renewal, structure stewardship, vegetation management, and system monitoring.	Further lowers the risk of equipment failure and severe weather by accelerating line replacements, reinforcing more structures, and expanding vegetation clearing and monitoring activities.

Phase II provided customers with an opportunity to confirm the outcomes that they value, as well as the level of spending and mix of investments that they would like to see included in the investment plan. The IRG Study presented transmission investments related to keeping pace with transmission renewal, and stewardship. In addition, transmission customers were invited to consider investment trade-offs related to maintaining buildings and facilities, and information technology.

In general, a plurality of customers preferred the Draft Plan (Scenario 2) over the accelerated or slower paced options.

- Across all customer types, a majority or near majority of customers selected Hydro One's Draft Plan level of spending.

- Customers expressed strong support for the replacement of aging and deteriorating transmission system assets to manage the risk of equipment failure and support growth across the province. These include the replacement of transmission station transformers and breakers, and high-impact underground transmission cables.
- Customers also expressed strong support for investments to enhance Hydro One's stewardship of the transmission system. A majority of customers support the draft plan, including replacing at-risk transmission lines, reinforcing wood poles and extending the life of steel towers and accelerating the clearing of overgrown trees.

This two-phased approach allowed Hydro One to ensure the final TSP for 2028-2032 is responsive to customer needs and preferences, as summarized in Table 2 below:

Table 2 - Reflection of Customer Feedback in the TSP

Objective	Customer Feedback	How it Appears in the Plan
Connections and Growth	Requirements for timely access and grid service	• Provide customers timely access to the network through customer connections and paced regional expansions (T-SA, T-SS)
Transmission Renewal	Maintain the current level of transmission station and cable health by replacing the highest-risk assets and managing failure risk over time.	• Address transformers and breakers at network stations and connection stations (T-SR-01, 02, 03). • Invest in replacement of underground cables (T-SR-16)
Transmission Stewardship	Lowers the risk of equipment failure and severe weather through balanced investment in line renewal, structural asset stewardship, vegetation management, and system monitoring.	• Renew poor condition overhead lines (T-SR-13). • Replace and refurbish wood poles (T-SR-04) and steel towers (T-SR-05). • Carry out proactive vegetation management (E-02-02).

2.7.4.5 INVESTMENT PLAN DEVELOPMENT

In developing and finalizing the proposed investments, Hydro One incorporated:

- **Feedback from Phase II of Customer Engagement** – incorporated customer feedback and reprioritized investments based on cost-outcome considerations specified by customers. In this regard, refinements reflected in the final TSP included increased transformer and conductor replacements in response to customer feedback; given the customer support for the draft plan, changes were minimal over the five-year term of the plan.
- **Updated costs, schedule and scope** – reprioritizing of investments based on updated cost and schedule maturity, in consideration of execution feasibility. In this regard, certain earlier assumptions around project maturity (which in turn impact planned pacing and costs for the 2028-2032 period) were modified to reflect updated information.
- **Ongoing Bulk Planning Studies** – Following the update of the transmission investment plan, the IESO identified a set of recommended solutions to address bulk system needs across South and Central Ontario, Eastern Ontario, and the North of Sudbury regions. As these solutions are mandatory investments under Hydro One's planning framework, these projects have been incorporated into Hydro One's proposed investment plan.

2.7.5 INVESTMENT PLAN APPROVAL & DELIVERY

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 described in SPF Section 1.7.

SECTION 2.8 – TSP – CAPITAL EXPENDITURES AND TRENDS

2.8.1 INTRODUCTION

This section provides an overview of Hydro One Transmission's proposed 2028-2032 capital expenditure plan, including the principal system needs addressed by the plan and the investment priorities that underpin the plan's development. The proposed investments are needed to maintain transmission system performance and address asset and operational risks during a period of unprecedented external demand, including from significant growth in customer connections, substantial growth in regional and bulk planning requirements including government-directed work, and the continued deterioration of critical transmission assets.

Over the historical and bridge period, the external drivers of Hydro One's Transmission capital expenditures have changed in a fundamental way, marking a pivotal inflection point in investments supporting growth and overall system resilience, and supporting economic development within the province. The demand for customer connections and system expansion has grown over the 2023-2027 period, and an escalation of these trends continues to drive investments over the 2028-2032 forecast period. As detailed in TSP Section 2.9, Hydro One has experienced an unprecedented and unexpected increase in demand for non-discretionary customer connections and required transmission system expansion and reinforcement since 2023. Relative to the levels of investment reflected in the OEB-approved Settlement Proposal (EB-2021-0110), the actual proportion of System Access investments has more than doubled, and the proportion of System Service investments has more than tripled. Together, investments in System Access and System Service are expected to comprise approximately 31.2% of actual transmission capital investments over the historical and bridge period, compared to the expectation that they would comprise approximately 11.1% as reflected in the approved Settlement Proposal.[1]

[1] Values relative to OEB-approved capital categories before progressive productivity (EB-2021-0110, Settlement Proposal, Table 22, p. 33).

The growth in connection volumes and system capacity contemplated in this investment plan is consistent with Ontario's Integrated Energy Plan (IEP), *Energy for Generations*, which contemplates a 75% increase in electricity demand by 2050 and identifies a need to accelerate the development of transmission infrastructure to enable economic growth, support electrification, and maintain a reliable and resilient electricity system. As described below, and in the relevant Investment Summary Documents (ISD), many of the transmission investments planned for the 2028-2032 planning period are essential to supporting economic development and growth in various areas of Ontario. These investments generally result from Ontario's Bulk System and Regional Planning Processes, as well as priority project designations by the Government of Ontario. Such investments include:

- Supporting housing and population growth through investment in high-growth regions, such as the Greater Toronto Area (including a new supply line to central Toronto), the Ottawa area, and Southwest Ontario, a region which "is experiencing some of the fastest industrial and population growth in the province."[2]
- Supporting industrial development in areas including the Windsor regional manufacturing and agricultural sector, industrial growth in the Niagara region, commercial and institutional growth in the Ottawa region, and technology-sector growth in Kitchener-Waterloo-Cambridge-Guelph.
- Enabling industrial and economic growth in Ontario's north, including mining and critical minerals development in northwestern Ontario; and stations work associated with the Greenstone Transmission Line, which the IEP described as "essential to support local communities, including First Nations, and enable greater economic self-determination across northern Ontario."[3]

The IEP prioritizes investment in the province's transmission infrastructure to support housing growth, the electrification and development of industry, and to enable new clean electricity generation, such as the development of Small Modular Reactor generation at Darlington and hydroelectric developments in northern Ontario. Hydro One's proposed

[2] Ontario Ministry of Energy and Mines, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7* (June 2025), p. 71 [IEP].
[3] IEP, p. 73.

capital plan is designed to meet these objectives while continuing to fulfill its obligations to maintain transmission reliability performance, address customer needs and priorities, and mitigate asset and operational risks.

During the 2023-2027 rate period, Hydro One responded to the increased demand for non-discretionary System Access and System Service work by optimizing its work portfolio to remain within its approved funding envelope, as discussed in TSP Section 2.9. The result was a proportionate decline in System Renewal investments relative to total investments to approximately 62.2%, compared to approximately 80.7% in the approved Settlement Proposal.

The external factors that drove System Access and System Service capital expenditures over the 2023-2027 period continue and are expected to escalate, accounting for approximately 49.7% of 2028-2032 capital expenditures, an increase from 31.2% in the current rate period. As further described below in Sections 2.8.4.1 and 2.8.4.3, a key driver of the increase in capital expenditures relative to the 2023-2027 period is the growth in investments driven by regional-planning and bulk-planning requirements. Together, these non-discretionary investments increase by approximately $6.2B relative to the approved settlement proposal and reflect the need for major transmission reinforcements identified through IESO-led planning processes to maintain reliability, increase transfer capability, and support Ontario's growing electricity demand. At the same time, Hydro One must continue to invest in System Renewal work, which is necessary to address the deteriorating condition, performance, and functional obsolescence of critical transmission assets and mitigate the risk of asset failure.

Table 1 and Figure 1 below provide a summary of Hydro One Transmission's forecast capital expenditures by OEB investment category.

Table 1 - Hydro One - Forecast Capital Expenditures ($M)

OEB Investment Category	Forecast Period[4]					% of Portfolio
	2028	**2029**	**2030**	**2031**	**2032**	
System Access	286.4	363.5	560.7	320.1	98.1	9.8%
System Renewal	955.2	1,072.4	1,435.0	1,864.4	1,766.6	42.6%
System Service	1,102.4	1,391.9	1,432.4	1,577.5	1,138.9	39.9%
General Plant (Transmission)[5]	287.9	259.0	275.3	247.2	217.6	7.7%
Total	**2,631.9**	**3,086.7**	**3,703.3**	**4,009.3**	**3,221.2**	**100%**
System OM&A[6]	634.5	-	-	-	-	**-**
General Plant - Prepaid (Transmission)[5]	70.9	65.4	70.4	58.4	44.0	**-**

[4] Where all or part of a project is expected to be owned by and included in the rate base of a newly licenced affiliated transmission partnership (i.e. will not form part of Hydro One's rate base), Hydro One has excluded the proposed capital expenditures from the 2028-2032 forecast. Further information may be found below.
[5] Details on General Plant expenditures and Prepaid related to cloud, are located in Exhibit B-04-01 General Plant System Plan (GSP).
[6] System OM&A reflects total Operations, Maintenance and Administration expenses. Further information is provided in Exhibit E-02-01. 2029 - 2032 is determined based on the Custom Revenue Cap Index identified in Exhibit A-04-02.

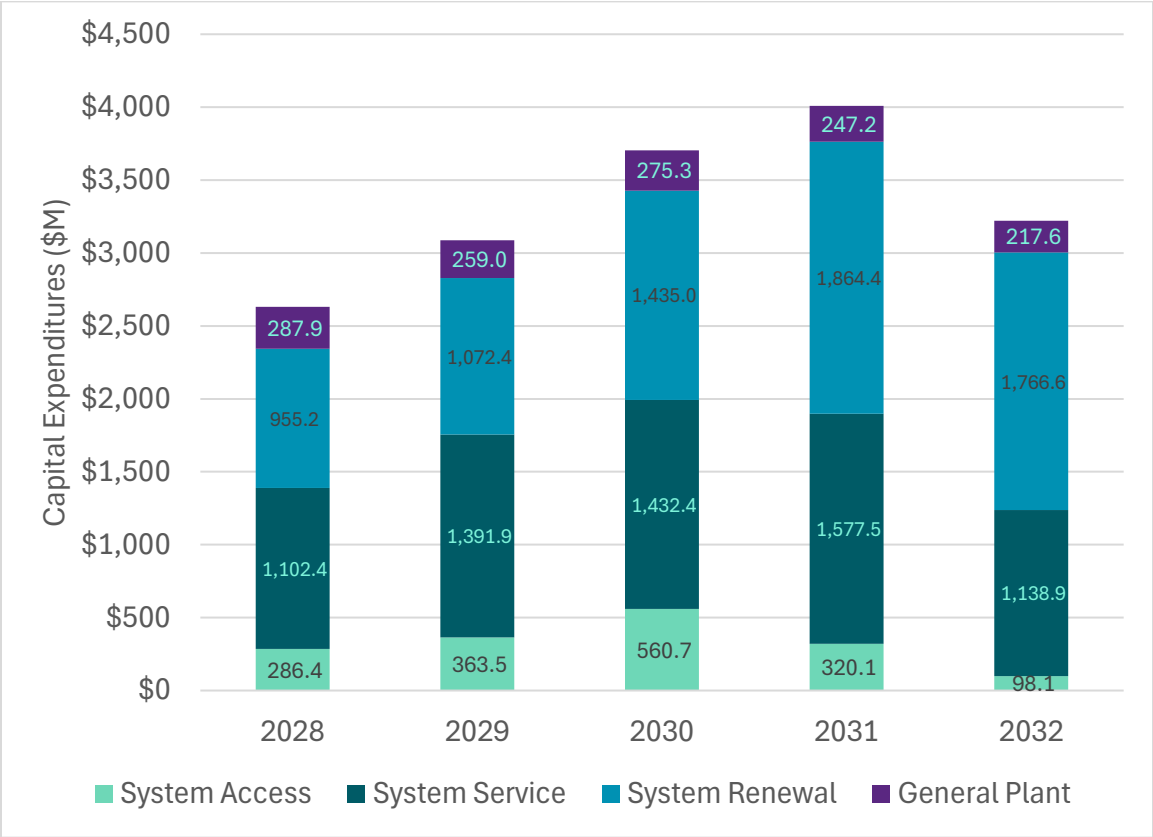

Figure 1: Hydro One - Forecast Period Capital Investment Summary ($M)

Over the 2028-2032 planning period, Hydro One plans to invest an average of $3,330.5M per year in Transmission capital, for a total of $16,652.4M, to maintain transmission reliability performance, to address increasing customer and system needs, to respond to government policy and directives related to system expansion, and to mitigate asset and operational risks by accomplishing the planned capital work.

Over the forecast period, Hydro One expects customer connection demand to increase materially relative to the 2023-2027 period, with the capacity enabled by customer connection investments rising from approximately 2,200 MW to more than 6,000 MW. This increase represents a continuation and acceleration of trends that emerged during the current rate period. During the 2023-2027 period, System Access investments increased significantly relative to approved levels as Hydro One experienced unprecedented growth in customer connections across multiple regions, increasing from

a plan to enable approximately 1,700 MW of customer connections to 2,200 MW. Due to the substantial increase in connection requests together with the sustained load growth projected in the IESO's Annual Planning Outlook (APO), Hydro One expects these trends to continue at an even greater scale. Hydro One continues to experience increased queries from large computational loads, and large-scale industrial customers across various market segments. This results in an increase in the number of System Access investments compared to the prior rate period, driven by a material increase in requests for new load connections from Local Distribution Companies, industrial customers and large commercial loads, requiring upgrades to existing, or new transmission stations and transmission lines.

Hydro One is also forecasting a significant increase in material Transmission investments driven by Bulk System Planning and Regional Planning recommendations, resulting in more than 60 System Service investments, of which 47 exceed the OEB materiality threshold, compared to 24 System Service investments in the OEB-approved amounts for the 2023-2027 rate period, of which only six exceeded the OEB materiality threshold and resulted from Transmission Regional and Bulk Planning process.

System Service investments driven by Bulk and Regional planning account for approximately $6.4B of all System Service expenditures over the 2028-2032 planning period.

Investments triggered by Bulk Planning alone account for approximately $5.3B, or 79% of all System Service related expenditures, arising from seven IESO-led bulk system planning studies that cover six regions, including Northern Ontario, South and Central Ontario, Eastern Ontario, North of Sudbury, Northeast Ontario and the Gatineau Corridor, which have resulted in implementation-ready recommendations for transmission reinforcements that require investment by Hydro One during the 2028-2032 planning period.

Investments triggered by Regional Planning alone account for approximately $1.2B, or 17% of all System Service related expenditures, arising from eight regional planning

studies that cover regions including Windsor-Essex, Kitchener-Waterloo-Cambridge-Guelph (KWCG), Greater Ottawa, North of Dryden, Toronto, St. Lawrence, GTA West and Niagara.

Further Bulk Planning and Regional Planning details are discussed in this exhibit as well as in TSP Section 2.12, T-SS-06, T-SS-09, T-SS-11, T-SS-12 and T-SS-16, respectively.

The increase in required System Service investments reflects the outcomes of formal IESO-led regional planning processes, bulk system planning studies, and government-directed transmission expansion initiatives that identify specific transmission reinforcements required to maintain reliability, ensure local area supply adequacy, accommodate forecast load growth, and enable new generation resources. As a result, investments such as ISD T-SS-10 (Greenstone Transmission Line Project–Station), ISD T-SS-11 (Bulk Planning, which includes 26 material investments), and ISD T-SS-12 (Regional Planning, which includes 14 material investments) are responsive to established planning recommendations and identified system needs. The proposed investments for 2028-2032 therefore represent a continuation and acceleration of a developing trend, as regional and bulk planning processes across Ontario continue to identify significant transmission reinforcements required to support growing electricity demand, increased system transfer capability, and connect new sources of generation.

Combined, the proportion of System Access and System Service capital expenditures are expected to increase by 936.7% over the 2023-2027 OEB-approved plan, accounting for approximately 49.7% of the 2028-2032 Transmission investment plan, compared to 11.1% of the 2023-2027 plan. If Hydro One becomes aware of new, material externally driven transmission investments[7] while the record of this Application is open, Hydro One has outlined its intention to update the investment plan in TSP Section 2.6, as required. To the extent that such investments arise after the OEB issues its Decision in this Application, the associated revenue requirement variance will be recorded in the Externally Driven

[7] As described in Exhibit G-01-03 Section 3.1 (e.g., IESO Regional Planning and Bulk System Planning related investments, compatible land use investments, or investments otherwise requested by the IESO or directed by the government).

Transmission Projects Variance Account according to the final baselines of the investments presented in Exhibit G-01-03 Section 3.1.

System Renewal investments are needed to maintain the underlying infrastructure, ensure safety, mitigate reliability risk and maintain compliance with regulatory, environmental and reliability standards. For the 2028-2032 planning period, Hydro One's planned System Renewal investments are increasing by 22.2% over 2023-2027 planned expenditures to address critical transmission assets that are in poor condition (as indicated by condition assessments), have inadequate performance, are functionally obsolete, or have failed. Over the 2023-2027 period, System Renewal investments are forecast to be $508.3M (8.8%) below planned spending levels primarily driven by funding reprioritization to the System Access and System Service categories to facilitate new customer connection capacity, local area supply needs and system upgrades. The System Renewal investments therefore also include investments that Hydro One reprioritized into the 2028-2032 planning period.

Many of the forecast System Renewal investments are expected to commence in the years immediately preceding or at the beginning of the application period, with the majority of construction, procurement, and commissioning activities occurring later in the forecast period. As investments advance from planning and design into execution phases, capital spending increases, resulting in higher expenditures toward the end of the planning horizon.

The 2023-2027 rate period has also been impacted by an unprecedented set of market forces that have resulted in sustained inflation, significantly increasing the cost of key electrical equipment and materials as discussed in SPF Section 1.8. Hydro One has continued to update project cost estimates to reflect market prices for materials and equipment, including power transformers, breakers, conductors, and other critical inputs. These updated costs now form the basis of the assumptions underlying Hydro One's 2028-2032 investment plans.

System Renewal, System Access and System Service investments are discussed in this section while General Plant investments are discussed in GSP Section 4.8.

2.8.2 SYSTEM OVERVIEW

Hydro One's transmission network is composed of the Bulk Electric System (BES)[8] and regional supply systems serving local areas. The elements of Hydro One's transmission system that form part of the BES connect major generation sources and deliver electricity from those sources to load centers throughout Ontario. Electricity delivered over the transmission network is supplied by 139 generators, as well as electricity imports into the province through interties. Hydro One's transmission system is interconnected to systems in Manitoba, Michigan, Minnesota, New York and Quebec, and forms part of the North American electricity grid's Eastern Interconnection. The Eastern Interconnection is a contiguous electricity transmission system that extends from Manitoba to Florida and from east of the Rocky Mountains to the North American east coast. Being part of the Eastern Interconnection provides benefits to Ontario, such as greater security and stability for Ontario's transmission system, emergency support when there are generation constraints or shortages in Ontario, and the ability to exchange electricity with other jurisdictions.

Hydro One's regional supply systems serve substantially all of Ontario (i.e., 97% of Ontario's transmission capacity) and transported approximately 146 TWh of energy throughout the province in 2025. Hydro One's transmission customers consist of 34 local distribution companies (including Hydro One's own distribution business) and 88 large industrial customers connected directly to the transmission network, including automotive, manufacturing, chemical and natural resources businesses.

Being part of the BES and the steward of the system that delivers the electrical energy necessary to power the provincial economy and meet society's daily needs, Hydro One is required to ensure that, among other things, its transmission system has sufficient

[8] Defined by NERC, the Bulk Electric System, unless modified by specific inclusion or exclusion criteria, consists of all transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

capacity to meet anticipated load growth and its transmission assets perform reliably. To achieve these outcomes, Hydro One must expand and reinforce its transmission system to accommodate the significant growth that is expected in customer connections, as well as to comply with reliability requirements and planning outcomes from regional and bulk planning initiatives, while addressing known risks posed by poor condition assets in a timely and cost-effective manner. Hydro One has 312 in-service transmission stations and approximately 28,000 circuit kilometers of high voltage (HV) lines. To manage its large population of transmission assets, Hydro One has robust asset management practices and investment planning processes that strive to ensure the Company, as a steward of its transmission system, addresses asset and system needs, maintains and improves system performance and equipment availability, and addresses customer priorities to provide reliable supply of electricity.

Hydro One's transmission system is governed by several technical, regulatory and operating standards, including North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) reliability standards, and Federal and Provincial environmental regulations that define how the transmission system and its facilities are designed to ensure system reliability and mitigate risk to the environment. Hydro One is required to operate and maintain its transmission facilities in compliance with the TSC, its licence, its operating agreement with the IESO, the Market Rules, all connection agreements, good utility practice, and in accordance with applicable criteria, standards and requirements relating to reliability as established by reliability organizations, which include NERC, the NPCC and the IESO. For example, most of Hydro One's transmission system has been designed with redundant facilities (e.g., double circuits, two transformers, two protection, control and telecommunications systems) per the requirements defined within NERC TPL-001-5, which dictates that a transmission system must be planned and reinforced such that it can withstand various outage conditions, such as a single element (N-1) while maintaining acceptable performance.

The transmission system is required to be built such that adequate and secure supply is assured over a wide range of conditions so that loss of one or more elements (line or station asset) will not result in any violation of thermal and stability limits. As a result of

this redundancy, there is a high degree of reliability. This means that the failure of one of the two transformers or circuits supplying a delivery point should not impact service to customers because they continue to receive uninterrupted supply from the remaining transformer or circuit. Such failures are nonetheless a major concern for Hydro One, the IESO and the LDCs that are being supplied from such a delivery point. This concern arises because replacing a failed asset takes a considerable amount of time, and at any point prior to replacement of the failed transformer and restoring the system to a redundant state, an outage impacting the second line, whether on the line itself or on the second transformer, would result in a lengthy delivery point interruption.

2.8.2.1 OEB RRF OUTCOMES AND CUSTOMER PRIORITIES

The proposed capital plan establishes Hydro One's investment needs and proposals on the basis of a rigorous and customer-focused planning framework. The proposed capital plan is consistent with the OEB's Renewed Regulatory Framework (RRF) and addresses the four RRF outcomes as follows:

- **Customer Focus** – services are provided in a manner that responds to identified needs and customer preferences;
- **Operational Effectiveness** – continuous improvement in productivity and cost performance is achieved; and distributors and transmitters deliver on system reliability and quality objectives;
- **Public Policy Responsiveness** – distributors and transmitters deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the OEB); and
- **Financial Performance** – financial viability is maintained; and savings from operational effectiveness initiatives are sustainable.

The mix and level of capital expenditures within the proposed plan are necessary for achieving outcomes that are valued by customers and required to maintain safe and reliable transmission system operation. These outcomes include funding mandatory investments to address system needs and service obligations including the significant anticipated growth in customer connections, responding to deteriorating system and asset

condition, and investing in infrastructure that is essential to Hydro One Transmission's core business functions and operations.

As described in TSP Section 2.7, feedback from customer engagement informed the development of the investment plan. Across all customer types, most customers support Hydro One spending at or above the level of investment included in Hydro One's draft plan presented to customers, as it relates to keeping pace with transmission renewal, and stewardship of the transmission system. Customers expressed strong support for the replacement of aging and deteriorating transmission system assets to manage the risk of equipment failure and support growth across the province. These include the replacement of transmission station transformers and breakers, and high-impact underground transmission cables. Customers also expressed strong support for investments to enhance Hydro One's stewardship of the transmission system. A majority of customers support the draft plan, including replacing at-risk transmission lines, reinforcing wood poles and extending the life of steel towers and accelerating the clearing of overgrown trees.

This direct customer input into the priorities and pacing of investments supplemented the comprehensive current state assessment, which incorporates a range of factors, including asset condition, load forecast, equipment performance history, operating restrictions, security incidents, environmental risks, compliance obligations, equipment defects, obsolescence, and health and safety considerations. The current state assessment establishes potential candidate investments as well as the fact base for assessing the probability and consequence of safety, reliability and environmental risks during investment planning. The quantification of risk mitigation benefits, as well as the consideration of qualitative benefits that customers value (e.g., outage coordination, proactive communication, power quality, and performance improvements), enable consistent prioritization and trade-off decisions to derive the final portfolio of investments.

2.8.3 TRANSMISSION INVESTMENT PLAN PRIORITIES

Hydro One's 2028-2032 Transmission investment plan is intended to achieve two investment priorities:

i. Maintaining a Reliable and Resilient Grid; and
ii. Meeting Ontario's Growing Demand.

These Transmission investment priorities exist within Hydro One's broader Strategic Priorities (SPF Section 1.7) and are aligned with customer needs and preferences (TSP Section 2.7), regulatory requirements, and the objectives of the IEP. The first priority, Maintaining a Reliable and Resilient Grid, primarily consists of System Renewal investments, and the second, Meeting Ontario's Growing Demand, consists of System Access and System Service investments.

Table 2 below provides a summary of capital expenditures by Hydro One Investment Priority. Each priority, and key corresponding investments, are described in the sections below.

Table 2 - Forecast Capital Expenditures by Investment Priority

Investment Priority	Forecast Period					% of Portfolio
	2028	2029	2030	2031	2032	
Maintaining a Reliable and Resilient Grid	955.2	1,072.4	1,435.0	1,864.4	1,766.6	46.2%
Meeting Ontario's Growing Demand	1,388.8	1,755.4	1,993.1	1,897.6	1,237.0	53.8%
Total System Access, System Renewal, and System Service Capital	**2,344.0**	**2,827.8**	**3,428.0**	**3,762.0**	**3,003.6**	**-**

2.8.3.1 MAINTAINING A RELIABLE AND RESILIENT GRID

A safe, reliable and resilient electricity system requires timely renewal of aging and deteriorated infrastructure, alongside sustained investment to address increasing asset risk. This priority focuses on restoring asset health and stabilizing overall system performance to reduce outage exposure risk and strengthen operating flexibility through targeted investments in:

- Poor-condition assets;
- Critical infrastructure required for safe and continuous operation; and
- Proactive replacement, refurbishment, and sustainment programs.

These investments incorporate current industry standards, enabling infrastructure that is resilient. This approach emphasizes system redundancy, and modern equipment designs to respond to changing conditions and maintain service continuity during severe weather events.

Given the combination of regulatory requirements and the critical role of electricity in Ontario's homes, businesses, and institutions, Hydro One cannot run its transmission assets to failure. Hydro One's priority is to maintain transmission facilities in-service. Accordingly, the proposed renewal spending is anchored on replacing assets based on their condition. Deteriorated assets in poor condition are replaced in a controlled manner so that any potential safety risks and other customer impacts from delivery point interruptions are minimized.

Hydro One's proposed investment plan is proactive and strategically paced to address the most critical and time-sensitive needs of the transmission system. As detailed in TSP Section 2.2.1.1, condition data for Hydro One's transmission system shows a clear and sustained deterioration across several major asset classes, signaling increasing renewal needs and heightened system risk. Deteriorated asset condition increases the probability of failure or loss of intended functionality and is therefore a key factor in Hydro One's investment planning.

Asset condition trends indicate increasing risk across the transmission system, with the most significant deterioration observed in transformers and wood structures:

- Poor-condition transformers increased from 16% in 2016 to 29% in 2025, reflecting a materially aging fleet and a growing reliability risk. Transformer failures reduce station redundancy, increase loading on remaining units, and elevate the likelihood of cascading outages.
- While approximately 10% of breakers are in poor condition, approximately 44% of the fleet is obsolete, increasing long-term operational risk due to declining vendor support and spare parts availability.

- Protection systems remain consistently high-risk, with about 26% of assets beyond expected service life, increasing the likelihood of mis-operations and compliance risk.
- Conductor condition has also degraded, increasing from 9% poor condition in 2016 to 14% in 2020, with only a partial recovery to 11% in 2025. Conductor health remains below historical levels, heightening susceptibility to mechanical failures and weather-driven outages.
- Wood structures show the most pronounced decline, with poor-condition assets rising from 12% to 19% from 2016 to 2025, signaling an aging pole population and a widening renewal gap. Given that approximately 42% of all transmission structures are wood, this significantly increases the risk of structural failures, safety hazards, and weather-related outages.

Overall, the growing proportion of poor condition and obsolete assets is increasing the risk of equipment failure, mis-operations, extended outages, and reduced operational flexibility, ultimately elevating the risk of customer interruptions.

This data demonstrates the need for sustained, risk-based capital investment to address deteriorating assets, stabilize condition trends, and preserve long-term system reliability and safety. These investments target the most pressing renewal needs required to: (i) maintain system performance and reliability to support the provincial economy and daily societal needs; (ii) meet regulatory and compliance obligations; (iii) mitigate public and employee safety risks; and (iv) address customer needs and priorities.

While reliability statistics are also an important consideration in System Renewal planning, they are lagging indicators of asset condition. Reliability performance provides an incomplete view of transmission asset risk, due to the largely redundant configuration of Hydro One's transmission system that helps to preserve supply continuity under single contingency events. By the time reliability statistics start to deteriorate, numerous customers will have been affected and service to the public compromised. Hydro One's transmission customers require a high level of reliability to sustain their operations. Even a small number of unplanned failures may result in large consequences that can impact

customers economically and operationally. The Customer Engagement process described in SPF Section 1.6 indicates that Hydro One's customers support the replacement of transmission system assets (such as transformers and conductors) in poor condition to maintain the overall health of the system. The need for maintaining the system in a reliable state is furthermore accentuated by the transformation of the resource mix in Ontario. With generation resources shifting and markets transitioning to a capacity driven model, there will be reduced flexibility for Hydro One to complete planned work. As a result, Hydro One has planned its System Renewal investments in alignment with customers' needs and priorities to ensure that transmission facilities are renewed in a timely manner and customer reliability is not jeopardized.

Hydro One's portfolio of investments to maintain the grid preserves the ability of the transmission system to continue providing safe and reliable service through a balanced set of interventions. Table 3 provides a summary of forecast capital expenditures under this priority. Further details on the individual investments are provided in TSP Section 2.12.

Hydro One proposes to invest approximately $7,093.5M over the 2028 - 2032 period, or approximately $1,418.7M per year on average, in the programs supporting this priority. Investments under this priority are divided into three groups: Stations Renewal, Lines Renewal, and Telecommunications Equipment and Infrastructure Replacement. Details on the key investments are set out under System Renewal in Section 2.8.4.2 below.

Table 3 - Maintaining a Reliable and Resilient Grid Investments ($M)

Investment Summary Document		Forecast Period					2028-2032 Total
		2028	2029	2030	2031	2032	
Stations Renewal							
T-SR-01	Transmission Station Renewal – Network Stations	169.8	104.5	97.5	163.8	159.6	**695.3**
T-SR-02	Transmission Station Renewal – Air Blast Circuit	38.1	29.3	17.5	63.3	82.5	**230.7**
T-SR-03	Transmission Station Renewal – Connection Stations	102.3	144.5	360.1	688.7	763.6	**2059.2**
T-SR-09	Transmission Station Demand and Spares	68.4	69.2	69.0	70.0	71.2	**347.9**
T-SR-10	Protection Relay Replacement Program	27.3	33.3	35.2	39.5	40.2	**175.5**
T-SR-19	Control Equipment Replacements	11.6	11.9	12.1	12.3	12.6	**60.5**
T-SR-21	Static VAR Compensators and Series Capacitors Replacement Program	5.0	5.1	5.2	5.3	5.5	**26.2**
T-SR-22	Transmission Station Component Replacement	76.0	78.8	82.7	85.3	87.7	**410.3**
Telecommunications Equipment and Infrastructure Replacement							
T-SR-11	Legacy SONET System Replacement	25.1	22.9	7.2	0.4	0.0	**55.5**
T-SR-12	Telecom Performance Improvements	15.1	14.4	12.8	6.6	6.8	**55.8**
T-SR-14	Mobile Radio System Replacement	15.4	21.0	12.8	8.0	0.0	**57.2**
T-SR-17	OPGW Infrastructure Projects	20.7	44.0	50.9	43.0	24.6	**183.2**

Witness: Donna Jablonsky; Mark Brodie

Line Renewal							
T-SR-04	Wood Pole Structure Replacements	89.7	91.5	93.4	95.2	97.1	**467.0**
T-SR-05	Steel Structure Coating Program	24.6	25.1	25.6	26.1	26.6	**127.9**
T-SR-06	Tower Foundation Clean/Coat & Life Extension Program	20.5	20.9	21.3	21.7	22.1	**106.5**
T-SR-07	Transmission Line Shieldwire Replacement	39.0	39.8	40.6	41.4	42.2	**203.1**
T-SR-08	Transmission Line Insulator Replacement	72.8	74.3	75.7	77.3	78.8	**378.9**
T-SR-13	Transmission Line Renewal	68.1	163.8	325.3	307.5	170.8	**1035.4**
T-SR-15	Transmission Line Emergency Restoration	11.4	11.6	11.9	12.1	12.4	**59.4**
T-SR-16	High Voltage Underground Cable System Replacements	43.6	55.8	67.0	85.6	50.8	**302.8**
T-SR-20	Tx Lines and Right of Way Other Investments	10.6	10.8	11.0	11.3	11.5	**55.2**
Total Capital Expenditure		**955.2**	**1,072.4**	**1,435.0**	**1,864.4**	**1,766.6**	**7,093.5**

2.8.3.2 MEETING ONTARIO'S GROWING DEMAND

Supporting Ontario's plans for electrification and growth is a core priority for Hydro One's 2028-2032 transmission capital plan. This priority includes the principal System Access and System Service projects that enable Hydro One to connect new and modified customer load, respond to external drivers, accommodate increasing demand and electrification, and address capacity constraints. Investments planned under this priority are intended to ensure that Hydro One remains able to connect customers, respond to demand growth, support externally driven infrastructure requirements, address emerging

capacity needs, and maintain system reliability and power quality across its service territory.

Hydro One is facing an unprecedented increase in customer connections and required transmission system expansion and reinforcement arising from growing demand, the policies set out in the IEP, and the plans developed through Ontario's Regional Planning and Bulk System Planning processes. Hydro One is obligated to connect and serve growing electricity demand and prioritize non-discretionary System Access and System Service investments to meet these needs.

Hydro One is the lead transmitter in 20 out of the 21 planning regions in Ontario, and its responsibilities in the Regional Planning process include implementing recommended solutions that arise from its license obligations to design, construct, operate and maintain its transmission system in accordance with the TSC to maintain the reliability and integrity of its system and to reinforce or expand its system as required to meet load growth.[9] Similarly, Hydro One must implement projects (i) where through the IESO's Bulk System Planning Process Hydro One is identified, expressly or implicitly, as the relevant transmitter, or (ii) where a transmission solution is designated by Order in Council as a priority transmission project and Hydro One, expressly or implicitly, is identified as the relevant transmitter to undertake the priority transmission project,[10] or (iii) where Hydro One is otherwise requested by the IESO.[11] These recommendations or directions are driven by the need to maintain the reliability and integrity of Ontario's bulk electricity transmission system in accordance with NERC, NPCC and IESO reliability standards and criteria. These solutions necessitate modifications to Hydro One's existing transmission system, or the construction of new transmission facilities, which Hydro One must implement to ensure compliance with reliability standards and criteria, as well as to meet load growth, in accordance with its Transmission Licence and the TSC. As described in the relevant ISDs, such investments are non-discretionary for Hydro One.

[9] As detailed in ISD T-SS-12 (Regional Planning).
[10] As detailed in ISD T-SS-11 (Bulk Planning) and ISD T-SS-12 (Regional Planning).
[11] As detailed in ISD T-SS-13 (Mitigation of MV/HV Fault Levels).

Hydro One plans to invest approximately $8,271.9M over the 2028-2032 planning period in the principal programs supporting this priority, including:

- $1,628.8M in System Access investments enabling a forecasted minimum 6,000 MW of capacity; and
- $6,643.1M in System Service investments arising from IESO-led bulk and regional planning processes, Orders in Council, IESO directives and recommendations, and other government directives, representing an additional minimum 10,000 MW of system transfer capability and enabling more than 2,500 MW of new generation capacity.

Table 4 provides a summary of forecast capital expenditures under this priority, divided between System Access and System Service. Details on key investments under each category are set out in Sections 2.8.4.1 and 2.8.4.3 respectively.

1 **Table 4 - Meeting Ontario's Growing Demand Summary ($M)**

Investment Summary Document		Forecast Period					2028-2032 Total
		2028	2029	2030	2031	2032	
System Access: Customer Connections and Economic Growth							
T-SA-03	Halton TS: Build a Second 230/27.6KV Station	0.0	0.0	11.2	18.9	15.0	**45.1**
T-SA-04	Connect Metrolinx Traction Substations	1.1	0.6	0.0	0.0	2.1	**3.7**
T-SA-05	New & Future Transmission Load Connection Plans	10.0	10.0	25.0	32.0	33.0	**110.0**
T-SA-06	Protection and Control Modifications for Distributed Energy Resources	0.0	0.0	0.0	0.0	0.0	**0.0**
T-SA-07	Compatible Land Use Projects	45.9	47.7	49.3	54.7	42.0	**239.6**
T-SA-08	H29/H30: Reconductor 230KV Circuits	10.4	4.9	0.0	0.0	0.0	**15.3**
T-SA-09	New Transformer Station in Northern York Region	7.3	19.7	25.0	-5.4	0.0	**46.6**
T-SA-10	Build Leamington Area Transformer Stations and Line	29.8	65.3	95.0	115.0	-13.7	**291.3**
T-SA-11	Customer Connections: Regulated Entities	114.7	157.9	311.8	98.3	13.9	**696.6**
T-SA-12	Customer Connections: Non-Regulated Entities	65.1	55.5	42.4	1.0	0.0	**163.9**
T-SA-Other	Other Transmission System Access	2.2	2.0	1.0	5.6	5.7	**16.6**
System Service: Enabling Regional and Bulk System Expansions							
T-SS-05	Merivale TS Add 230/115 kV Autotransformers	1.6	0.3	0.0	0.0	0.0	**1.9**
T-SS-06	Southwest GTA Transmission Reinforcement	9.0	12.5	8.1	3.0	0.0	**32.7**
T-SS-09	West of London Transmission Reinforcement	55.4	42.8	28.9	0.5	0.0	**127.7**
T-SS-10	Greenstone Transmission Line Project - Stations	20.0	20.0	16.0	19.0	20.0	**95.0**
T-SS-11	Bulk Planning	762.4	1,042.4	1,097.0	1,291.6	939.4	**5,132.8**
T-SS-12	Regional Planning	216.4	250.7	252.9	237.3	170.1	**1,127.4**
T-SS-13	Mitigating Short-Circuit Limitations at Hydro One Stations to Enable Resource Connections	14.9	16.8	16.9	10.0	5.0	**63.6**
T-SS-14	Bowmanville SS Loop Replacement	0.2	0.3	11.0	16.9	2.3	**30.8**
T-SS-16	Waasigan Station Work	15.2	0.0	0.0	0.0	0.0	**15.2**
T-SS-Other	Other Transmission System Service	7.4	6.0	1.5	-0.8	2.1	**16.2**
Total Capital Expenditure		**1,388.8**	**1,755.4**	**1,993.1**	**1,897.6**	**1,237.0**	**8,271.9**

2.8.4 FORECAST CAPITAL EXPENDITURES AND TREND ANALYSIS

Over the 2028-2032 planning period, Hydro One plans to invest an average of $3,330.5M per year in Transmission capital, for a total of $16,652.4M to maintain transmission reliability performance, to address increasing customer connections and system capacity needs, to respond to government policy and directives related to system expansion, and to mitigate asset and operational risks by accomplishing the planned capital work. Planned expenditures are higher than the current 2023-2027 rate period's OEB-approved and actual expenditures due to the increase in the planned transmission work across System Access, System Renewal and System Service categories. Hydro One's planned 2028-2032 capital expenditures relative to the historical amounts are shown in Table 5 and Figure 2.

The increase in forecast capital expenditures compared to the prior rate period is driven by an unprecedented rise in customer connection requests that have led to enabling approximately 6,000 MW compared to 2,200 MW in the prior rate period and a significant increase in Transmission Regional and Bulk Plan investments driven by recently published Bulk and Regional Plans. Combined, these two OEB categories, System Access and System Service, account for 49.7% of the 2028-2032 Transmission investment plan compared to 11.1% of the 2023-2027 OEB-approved envelope. System Renewal expenditures account for a further 42.6% of forecast investments, down from 80.7% of the prior OEB-approved envelope, notwithstanding a modest increase relative to the historical and bridge period expenditures.

System Access and System Service investments collectively account for approximately 79.1% of the plan-over-plan increase between the 2023-2027 actual and forecast spending and the 2028-2032 Transmission investment plan. The remainder of the plan-over-plan increase is divided between System Renewal (approximately 13.6%), and General Plant (approximately 7.3%).

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Table 5 - Hydro One - Ten-year Capital Plan

OEB Category	Historical Actual/Forecast ($M)				Bridge Forecast ($M)	Forecast Period (Planned $M)					2028-2032 Total
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
System Access	62.6	106.9	148.9	204.4	253.0	286.4	363.5	560.7	320.1	98.1	**1,628.8**
System Renewal	971.6	1,209.7	1,103.7	1,087.1	926.6	955.2	1,072.4	1,435.0	1,864.4	1,766.6	**7,093.5**
System Service	133.9	125.7	141.0	459.5	1021.3	1,102.4	1,391.9	1,432.4	1,577.5	1,138.9	**6,643.1**
General Plant[12]	146.3	134.3	111.0	86.8	82.9	287.9	259.0	275.3	247.2	217.6	**1,287.0**
Total	1,314.4	1,576.5	1,504.6	1,837.8	2,283.9	2,631.9	3,086.7	3,703.3	4,009.3	3,221.2	**16,652.4**
Prepaid Related to Cloud (Transmission)[12]	-	-	10.3	48.3	31.2	70.9	65.4	70.4	58.4	44.0	**309.0**

[12] Details on General Plant expenditures and Prepaid related to cloud, are found in Exhibit B-04-01 General Plant System Plan (GSP).

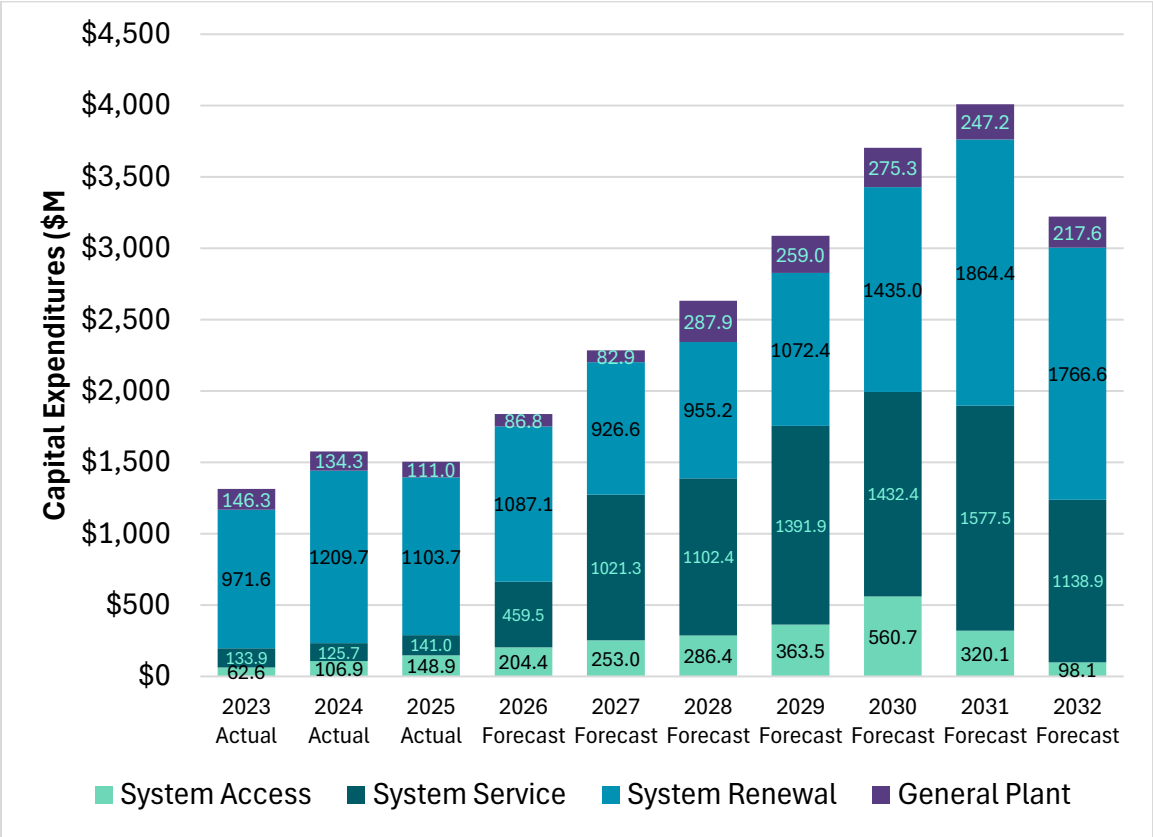

Figure 2: Ten-year Capital Plan

2.8.4.1 SYSTEM ACCESS

System Access investments are non-discretionary to facilitate new load and generation customer connections, and for transmission system modifications to accommodate third-party requests. Hydro One's planned 2028-2032 System Access expenditures are higher than 2023-2027 actual and forecast expenditures due to an unprecedented increase in customer connection requests that will enable at least 6,000 MW of capacity relative to the 2,200 MW enabled over the prior rate period. The forecast for new connections is driven by connection requests in various parts of Ontario, particularly in South-West Ontario, the Greater Toronto region, Greater Ottawa region and the Hamilton to Nanticoke regions.

The 2028-2032 System Access category forecast includes 27 material investments related to customer connections, and its expenditures are expected to result in the construction of 19 new or expanded transmission stations, 1 transmission line reconductoring, 1 transmission line relocation, 6 new HV connections to connect new Hydro One stations, 4 new HV connections to connect Local Distribution Company (LDC) owned stations, and 4 new HV connections to large load customers. In contrast, Hydro One's 2023-2027 rate application forecast includes only eight material investments in the System Access category related to customer connections, including investments to build five new transmission stations, connect one industrial customer and reconductor one transmission line.

System Access investments account for $3,561.7M of gross capital expenditures for the 2028-2032 planning period. However, a significant portion of these investments are recoverable from customers in accordance with the TSC, resulting in net capital expenditures of $1,628.8M or 9.8% of the total net capital expenditures over the five-year plan, as shown in Table 6 below. These expenditures represent a 421.6% increase over the 2023-2027 plan and a 110.0% increase over 2023-2027 actual and forecast spend.

Table 6 - Hydro One - System Access Capital Expenditures ($M - Net)

OEB Category	Historical Period Actual/Forecast				Bridge	Forecast Period					
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2028-2032 Total
System Access	62.6	106.9	148.9	204.4	253.0	286.4	363.5	560.7	320.1	98.1	**1628.8**

The load and generation connection investments are customer driven, based on requests for connection capacity, as well as reliability needs identified through the regional planning process (as described in SPF Section 1.2) or in connection with the IESO's resource acquisition. Transmission asset modification investments are driven by third-party requests to facilitate or permit compatible land use. All System Access investments forecast over the planning period are based on investment needs identified through a load customer and/or third-party requests, or through regional planning. These investments are non-discretionary, since Hydro One is required to provide transmission access when requested pursuant to the terms of its Transmission Licence and the TSC. The magnitude and volume of work in this investment category can vary significantly year-over-year based on customer requirements.

System Access investment over the planning period will enable at least 6,000 MW of capacity, representing 2.7 times more than that enabled over the 2023-2027 period. During the historical period, customer connection activity has increased significantly, reflecting growing demand for access to the electricity system. Hydro One enabled approximately 2,200MW relative to a plan of 1,700MW over the 2023-2027 period, representing an increase of approximately 29%. In 2024, Hydro One managed approximately 97 customer connection projects. By the end of Q2 2026, the number had risen to 166 projects, representing an increase of more than 70%. For the generation project portfolio, there were approximately 19 new connection projects in 2024. In 2026 and 2027, Hydro One anticipates approximately 50 new applications primarily driven by both customer connections and IESO's resource procurement initiatives, representing an increase of over 250%.

Hydro One plans to undertake $2,247.7M of gross capital work for 56 projects over the 2028-2032 planning period that are derived from regional planning and growth forecasts or are requested by regulated entities, such as LDCs, and non-regulated entities, such as industrial customers. By comparison, the 2023-2027 plan included 25 connection projects representing approximately $437.6M in gross capital expenditures. While the size and complexity of these projects vary from year to year, the forecast portfolio reflects a material increase in both the number of projects and a greater proportion of larger, more complex investments. For example, new or expanded station projects are generally more complex and resource-intensive than HV line connection work, requiring greater construction effort as well as more extensive outage planning, scheduling and coordination. The 2023-2027 period included 14 HV line connection projects and five new dual-element spot network (DESN) stations, whereas the 2028-2032 plan includes 8 HV line projects and 19 new or expanded DESN stations. The costs of the majority of the projects in this category are recoverable from third parties, resulting in a net expenditure of $1,258.8M. As summarized below, these investments are organized into regulated entity connections and non-utility customer connections. System Access expenditures also include investments related to compatible land use, as set out below.

Regulated Entity Connections

New customer connections for regulated entities account for $2,017M gross capital, $1094.9M net capital. Key drivers of investments in this category include investments in the Windsor-Essex Region to construct two load connection stations in the Kingsville-Leamington area, and two load connection stations in the Coatsworth area, together with associated new 230 kV line construction to support growing agricultural demand and system restoration needs. On a net basis, these investments are forecast to be approximately $495M. Investments responding to growing need in the Burlington to Nanticoke Region amount to $246.6M of net capital expenditures to connect load customers over the 2028-2032 planning period. These investments are to build five DESN to meet the growing load in the Burlington to Nanticoke Region. More details for customer connection investments are further described in TSP Section 2.12, T-SA-03, T-SA-08, T-SA-09, T-SA-10, and T-SA-11.

Non-Utility Customer Connections

Over the planning period, Hydro One plans to undertake $230.5M of gross capital work to directly connect large scale non-utility customers to the transmission system. Hydro One estimates that approximately 1,800 MW will be connected over the planning period, arising from industrials, transportation electrification, and large computational loads. The timing and magnitude of these connections are dictated by the large transmission customers. A significant portion of this work is recoverable from the customers and the net capital impact of this work is approximately $163.9M in net expenditures within the 2028-2032 period. The related investments are further described in TSP Section 2.12 T-SA-12.

Compatible Land Use

Investments to support compatible land use and related transmission asset modifications over the five-year period amount to approximately $390M of gross capital expenditures. Since a portion of this work is recoverable from customers, the net capital impact of this work is approximately $240M within the 2028-2032 planning period. These investments include the relocation, removal, or reinforcement of transmission assets to facilitate third-party projects (e.g., roadwork, transit systems, and other major infrastructure or development work) that may encroach upon or impact Hydro One assets and right-of-way. The size and complexity of these projects vary from year to year, and the cost of the majority are recoverable from third parties. Investments over the forecast period include the West Toronto Transmission Line Relocation project as proposed by Metrolinx to relocate transmission circuits K1W/K3W between Eglinton Avenue West and St. Clair West Avenue in Toronto using underground cables to accommodate transit system expansion and development, as further described in TSP Section 2.12, T-SA-07.

2.8.4.2 SYSTEM RENEWAL

System Renewal investments focus on replacing assets in a controlled manner before they fail so that any potential safety risks and other customer impacts from delivery point interruptions are minimized. System Renewal investments are underpinned by verified asset condition and have been selected based on condition, performance and obsolescence criteria, considering customer needs and priorities and equipment right-

sizing. The investments have been prioritized through a rigorous investment planning process. Hydro One's priority is to ensure transmission facilities remain in-service.

For the 2028-2032 planning period, Hydro One's planned System Renewal investments are increasing by 22.2% over 2023-2027 planned expenditures and 33.9% over 2023-2027 actual and forecast expenditures. These investments address critical transmission assets that are in poor condition (as indicated by condition assessments), have inadequate performance, are functionally obsolete, or have failed, and to ensure safety, mitigate reliability risk and maintain compliance with regulatory, environmental and reliability standards. System Renewal also includes investments that Hydro One reprioritized during the 2023-2027 period to accommodate increasing demand in the System Access and System Service categories, as described further in TSP Section 2.9.

System Renewal investments account for $7093.5M or 42.6% of transmission capital expenditures for the 2028-2032 planning period, as shown in Table 7 below.

Table 7 - Hydro One - System Renewal Capital Expenditure Summary ($M)

OEB Category	Historical Period Actuals[13]				Bridge	Forecast Period					
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2028-2032 Total
System Renewal	971.6	1209.7	1,103.7	1,087.1	926.6	955.2	1,072.4	1,435.0	1,864.4	1,766.6	7,093.5

As discussed in section 2.8.3.1 above, asset condition trends demonstrate escalating asset and system risk on the transmission system and underline the necessity of sustained, condition-based capital investment to address poor asset condition, reduce outage risk, and ensure long-term reliability and public safety for transmission customers.

While Hydro One has some discretion in the timing of certain System Renewal investments, these investments must be completed to address assets in deteriorated

[13] Historical Period Actuals includes forecast values for 2026 and 2027.

condition. Hydro One has paced the 2028-2032 System Renewal investments to balance risk and cost in a manner that aims to maintain system and customer reliability through proactive condition-based replacement.

As described above in section 2.8.3.1, System Renewal investments comprise three categories of investments: Stations Renewal, Telecommunications Equipment and Infrastructure Replacement and Lines Renewal. Key investments are summarized below.

Stations Renewal Investments

Stations Renewal investments are required to replace transformers, circuit breakers, protection and control, and telecom equipment that form part of the BES and regional supply systems serving local areas. The assets proposed for replacement reflect known risks and condition informed by maintenance, testing, and operational needs, as further discussed in TSP Section 2.2.2.

The condition of Hydro One's transmission stations continues to decline. A substantial population of assets is already in poor condition and requires timely intervention to avoid further degradation of system performance. Deteriorated assets have a direct impact on the reliability and resilience of the transmission system. For example, while a transformer-related outage may not immediately interrupt customers due to built-in station redundancy, it does eliminate that redundancy for the duration of the outage. This increases the supply risk to connected customers, places additional loading and thermal stress on the remaining in-service transformers and can necessitate the postponement or cancellation of planned outages needed to perform routine or preventive maintenance.

Each unplanned transformer failure results in the loss of redundancy for an extended period, often several months, until repairs or replacement can be completed. During this time, the station and the customers it serves remain exposed: a subsequent failure of the companion transformer can lead to severe operational consequences, including widespread customer outages and significant system disruption. For these reasons, reducing unplanned transformer failures is essential to maintaining system reliability and ensuring continuity of service.

Investments within the Stations Renewal portfolio are therefore critical. They target the replacement and refurbishment of key station components necessary to preserve transmission system performance and support the reliability of the provincial electricity system. These investments address the highest-risk assets, mitigate the consequences of deteriorated equipment, and help ensure that the transmission system continues to operate safely and reliably as asset condition declines.

The Hydro One transmission system includes two types of stations with complementary functions: network stations and connection stations.

Network stations form part of the BES and are the backbone of the transmission system in Ontario, interconnecting generation sources such as nuclear or hydroelectric to load centers and enabling secure and reliable power flows. Failure to renew deteriorating assets would materially increase system reliability risk, including the loss of redundancy, exposure to cascading outages, and reduced operational flexibility during contingency events. The proposed investments directly mitigate these risks and ensure compliance with IESO, NERC and NPCC planning criteria and reliability standards. Investments in network stations are driven by station asset condition and prioritized based on safety, compliance, reliability and environmental impacts. Collectively, these investments deliver customer and system value by sustaining the reliability, safety, and resilience of the transmission system and deliver long-term value to customers by avoiding the higher costs and service impacts associated with unplanned failures and reactive replacements.

Connection stations are a critical component in regional supply systems serving local areas, providing transmission delivery points for load connections. These stations, via step-down power transformers, transfer power from higher voltages to lower voltages to facilitate the distribution of power via the downstream distribution network. Hydro One's main customers at connection stations are LDCs and large industrial customers. LDCs, in turn, serve Ontario's residential, commercial, institutional and small industrial end-users. The end-user facilities that are affected by any issues at Hydro One's connection stations include such critical infrastructure as telecommunications systems, water and wastewater treatment facilities, hospitals, airports and transportation systems, schools and

universities. In essence, Hydro One's connection stations provide the electrical energy necessary to power the provincial economy and meet society's daily needs.

Hydro One uses two complementary approaches for the planned renewal of major network and connection station assets based on asset condition, system needs, and project complexity. Both approaches focus on the replacement of major power equipment (e.g. transformers, breakers, protection systems) that are in poor condition, have inadequate performance, are obsolete, or in the case of protection systems, are beyond expected service life (ESL).

In addition to planned stations renewal investments, the Transmission Station Demand and Spares investment involves the emergency replacement of transmission station assets that have failed or are at an imminent risk of failure and the procurement of strategic spare inventory.

Key stations renewal investments during the 2028-2032 planning period include:

- **Integrated Stations Investments:** Where multiple critical assets require replacement and station-wide coordination is needed, Hydro One may employ an Integrated Station Approach to renew major power system equipment, including transformers, breakers, switchgear, and protection and control systems through a single project in coordination with broader regional or bulk system needs. Ancillary equipment in need of replacement will also be included. This approach maximizes outage efficiency, reduces customer disruptions, and provides opportunities for station modernization, reliability improvements, and configuration enhancements. The proposed plan contains 149 investments amounting to $2,985.2M during the 2028-2032 period that will replace power equipment using an Integrated Station Approach. This decrease of $60.2M compared to the 2023-2027 prior rate period is primarily driven by the composition and scope of the investments in the planned project portfolio. The current plan includes investments focused on sustaining and maintaining existing station assets. The pacing of expenditures reflects the timing and delivery schedules of the planned projects and the prioritization of

investments, based on total risk mitigation, risk spend efficiency, and contribution to desired outcomes. The integrated stations renewal investments are further described in TSP Section 2.12, T-SR-01, T-SR-02, and T-SR-03.

- **Component Replacement Investments:** When a full station renewal is not required or practical, Hydro One uses a Component Replacement Approach to replace specific high-risk, deteriorated assets. This targeted approach addresses condition-related risks in a timely manner, helping prevent equipment failures, safety and environmental incidents, customer outages, and operational constraints. During the 2028-2032 forecast period, Hydro One's component replacement investments comprise the targeted replacement of protection systems (T-SR-10 and T-SR-21); programs that target individual poor condition transformers, circuit breakers, other station assets,[14] and civil infrastructure assets that are not included within larger integrated station projects (T-SR-22); and control equipment replacements (T-SR-19). These investments amount to $672.5M during the 2028-2032 period. The investment cost for the 2028-2032 period is $364.0M higher than the 2023-2027 actual and forecast expenditures primarily due to higher and sustained inflationary pressures and increased pacing to replace the majority of currently known poor condition (beyond ESL for protection assets) and obsolete station components that are not included in an integrated station renewal project.

- **Transmission Station Demand and Spares:** This program amounts to $347.9M over the 2028-2032 period, which involves the emergency replacement of transmission station assets that fail during the 2028-2032 period or are found to be at an imminent risk of failure as well as the procurement of strategic spare inventory. This investment is to ensure that Hydro One maintains an adequate inventory of critical transmission assets to facilitate the expedient replacement of failed or deficient components at transmission stations and that Hydro One

[14] Other station components include equipment such as switches, capacitor banks, instrument transformers, insulators, arresters, GIS/GIL, low voltage station service switchgear, batteries, chargers, grounding, civil infrastructure, etc.

continues to comply with its obligations for mitigating safety, system reliability, and environmental risks that a failure might cause. These stations are critical to the bulk system, and to directly connected local distribution, industrial and commercial customer reliability. Costs for the investment are based on current supply chain prices and typical replacement costs applied to the expected demand based on long-term historical failure rates. Investment expenditures for the 2028-2032 period are expected to be $98.3M higher than 2023-2027 actual and forecast expenditures primarily due to cost escalation, and a shift in the mix of other station component failures during the historic period. This investment is further described in TSP Section 2.12, T-SR-09.

Telecommunications Equipment and Infrastructure Replacement

The Telecommunications Equipment and Infrastructure Replacement portfolio amounts to planned expenditures of $351.7M over the 2028-2032 planning period across four complementary investments that sustain and modernize Hydro One's critical telecommunications infrastructure. Three investments focus on Hydro One's core telecommunication network and are primarily utilized for protection and automation communications among control centres and transmission stations:

- Legacy SONET System Replacement replaces obsolete SONET equipment with modern MPLS technology to maintain reliable protection and control communications critical to grid operations, as further described in TSP Section 2.12, T-SR-11;
- Telecom Performance Improvements replaces obsolete microwave communications equipment within a particular segment of the core telecommunication network with Optical Ground Wire (OPGW), improving reliability and supporting compliance requirements, as further described in TSP Section 2.12, T-SR-12; and
- OPGW Infrastructure Projects expands Hydro One-owned fibre infrastructure through targeted OPGW installations, to close network gaps, reduce dependence on leased third-party telecommunications facilities, and improve network resilience and reliability, as further described in TSP Section 2.12, T-SR-17.

The fourth investment, Mobile Radio System Replacement, replaces Hydro One's aging provincial mobile radio system with a modern communications solution to ensure reliable voice communications for field crews during routine operations and emergency restoration activities, as further described in TSP Section 2.12, T-SR-14.

Combined, these investments represent an increase of $191.0M relative to 2023-2027 actual and forecast expenditures. Investment expenditures are expected to increase primarily due to cost escalation, deployment of modern communication technologies as described above, and increased work volume to complete work reprioritized into the 2028-2032 planning period to accommodate the needs of the System Access and System Service categories during the 2023-2027 period.

Lines Renewal and Component Replacement

Lines renewal investments involve the replacement of poor condition overhead conductors, shieldwire, insulators, and structures or structure components. These investments are required to sustain performance and reliability of the transmission system as well as mitigate safety concerns associated with failing assets as a majority of assets are located in publicly accessible areas. Lines-related renewal investments have been prioritized based on detailed asset condition assessments confirming replacement candidates to be in poor condition.

Similar to transmission station assets, poor condition line assets remain in the system, presenting a risk of failure with associated consequences to safety and reliability. The overhead conductor is the most vulnerable and critical component of transmission lines. Currently, 3,079 circuit-kms or 11% of Hydro One's conductor fleet have been confirmed to be in poor condition. In addition, there are another 5,296 circuit-kms of overhead conductors (19% of overall population) exhibiting some form of deterioration. Deterioration of an overhead conductor cannot be stopped or reversed, and, as such, these assets will eventually degrade to the point of being in poor condition, requiring replacement. There are other transmission line components (e.g., wood pole structures, steel structures, insulators, shieldwires) that are integral and critical to safe and reliable operation of the transmission system. Hydro One has a large population of poor condition transmission

structures and foundations, shieldwires as well as defective insulators that require immediate attention.

Key lines investments during the 2028-2032 planning period include:

- **Line Renewal:** Hydro One plans to invest $1,035.4M in transmission line renewal during the 2028-2032 period. The company plans to replace 1,369 circuit-kms, or 45% of the known poor condition conductor that forms part of the BES or regional supply systems, including 13 material investments. In the 2023-2027 rate period, Hydro One reprioritized the majority of line renewal investments into the 2028-2032 period to accommodate the needs of the System Access and System Service categories. Coupled with cost escalation, the forecast investment expenditures for this investment are expected to increase by $936.1M for the 2028-2032 period relative to 2023-2027 actual and forecast expenditures. These investments are needed to replace conductors in poor condition, or in some cases, address extensive structure deterioration. When developing a line renewal investment, Hydro One also considers other line components for replacement such as insulators, structure and structure components, and shieldwires that have been confirmed to be in poor condition. The majority of circuits are located in publicly accessible areas, where a failure of the poor condition assets poses safety risks. Furthermore, most of the work in this category addresses lines that directly service customers. These lines serve a vital function in providing service to a variety of customers, such as smaller towns, First Nations communities and businesses, pipeline compressor stations, and large load facilities such as mines and paper mills (see TSP Section 2.12, T-SR-13). Hydro One is committed to ensuring reliable supply to all customers.

- **Transmission Line Component Replacement:** To address poor condition line assets on circuits where conductor renewal is not yet needed, the investment plan includes several programs amounting to $1,283.4M, which address thousands of poor condition transmission line components including wood pole structures, insulators, and conventional shieldwire. These components are integral parts of the transmission system required to enable and support the overhead conductor

to perform its functions. Major investments within this group include Wood Pole Structure Replacement (T-SR-04) and Transmission Line Insulator Replacement (T-SR-08).

Hydro One plans to invest $467.0M over the 2028-2032 period in the Wood Pole Structures Replacement program. Proactive replacement of poor condition wood pole structures is necessary to maintain public safety, and customer and system reliability. Ongoing condition assessments have identified more poor condition wood pole structures with 19% of the fleet currently in poor condition, reflecting an aging pole population and a widening renewal gap. In the current rate period, Hydro One reprioritized wood pole structure replacements into the 2028-2032 period to accommodate the needs of the System Access and System Service categories which, along with the deteriorating condition of the fleet, has resulted in an increased pace of replacement during the 2028-2032 period. As a result of this increased pace of replacement coupled with cost escalation, expenditures under this program are expected to increase by $140.1M relative to 2023-2027 actual and forecast expenditures.

Hydro One also plans to invest $378.9M over the 2028-2032 period in the Transmission Line Insulator Replacement program, which represents an increase of $88.2M relative to 2023-2027 actual and forecast expenditures. Proactive replacement of defective porcelain insulators is necessary to reduce public safety risk associated with insulator failures, resulting in conductor drops, and maintain system reliability by avoiding forced outages. Electric Power Research Institute (EPRI) testing and observed failures have caused Hydro One to include 1950s insulators for replacement (previously 1960). In the current rate period, Hydro One reprioritized line insulator replacements into the 2028-2032 period to accommodate the needs of the System Access and System Service categories which, along with the inclusion of the defective 1950s insulators, has resulted in an extension of the replacement program in the 2028-2032 period and an increase in the remaining number of insulators to be replaced.

See TSP Section 2.12, T-SR-04, T-SR-05, T-SR-06, T-SR-07, and T-SR-08 for Transmission Line Component investments.

Similar to the stations renewal investments, Hydro One prioritizes its lines investments to deal with the most pressing system and asset needs. The proposed plan is the minimum level of investment needed to maintain system performance.

2.8.4.3 SYSTEM SERVICE

System Service investments are required to maintain inter-area network transfer capability, ensure local area supply adequacy, mitigate system risks related to safety, security and reliability, and address customer power quality concerns. Most of these investments are non-discretionary with the majority having been identified as a result of regional planning processes or IESO bulk planning studies.

During the 2023-2027 rate period, Hydro One experienced unprecedented and unexpected growth in customer connection demand and system expansion needs. This growth is expected to continue and intensify throughout the 2028-2032 planning period. As a result, Hydro One’s planned 2028-2032 System Service expenditures are significantly higher than its 2023-2027 actual and forecast expenditures, driven by an increase in Transmission Regional Planning and Bulk Planning investments resulting from recently published Bulk and Regional Plans, compared to the prior rate period. Together, these investments will increase system transfer capability by at least 10,000 MW and support the integration of more than 2,500 MW of new generation capacity. The increase in System Service investments reflects the growing number of priority transmission projects designated by the Government of Ontario through Orders in Council. Pursuant to Ministerial Directives to the OEB, these projects have been incorporated into Hydro One's transmission licence as conditions requiring Hydro One to undertake their development. Collectively, these investments support Ontario's economic growth by enabling population and housing growth, electrification, and new industrial development, as outlined in Chapter 3 of the IEP.

System Service investments account for approximately $6,816.0M of gross capital expenditures over the 2028-2032 planning period. However, some of these investments are recoverable from customers in accordance with the Transmission System Code, resulting in net capital expenditures of $6,643.1M or about 39.9% of total net transmission capital expenditures over the 2028-2032 period, as summarized in Table 8.

Table 8 - Hydro One - System Service Capital Expenditure Summary ($M)

OEB Category	Historical Period				Bridge	Forecast Period					
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2028-2032 Total
System Service	133.9	125.7	141.0	459.5	1021.3	1,102.4	1,391.9	1,432.4	1,577.5	1,138.9	6,643.1

As detailed below, the 2028-2032 System Service expenditures include 47 material investments that will result in the construction of 8 new HV transmission stations, 26 HV transmission station expansions, and approximately 387 km of new HV lines, excluding lines to be owned within ATP. Of these, 42 material investments emanated from the Transmission Regional Planning as discussed in SPF Section 1.2, and Bulk Planning as described in TSP Section 2.6 and ISD T-SS-11. In contrast, Hydro One's 2023-2027 plan forecasted only nine material investments in the System Service category, of which six investments resulted from Transmission Regional and Bulk Planning process.

The sections below summarize forecast investments that are driven by bulk planning and regional planning.

Bulk System Planning

Bulk System Planning is performed by the IESO in various bulk planning regions, and for the province as a whole, to address system issues that are provincial in nature, such as provincial generation capacity and transmission system solutions to enable the reliable and economic transmission of power across Ontario. As the lead transmitter in Ontario, Hydro One is obligated to implement most transmission solutions that are recommended through the bulk system planning process. These recommendations are driven by the

need to maintain the reliability and integrity of Ontario's bulk electricity transmission system in accordance with NERC, NPCC and IESO reliability standards and criteria. A summary table showing a list of investments that are driven from different bulk planning studies is shown in Table 9. Further details of these bulk planning studies and their recommendations leading up to the list of projects below are provided in TSP Section 2.12, T-SS-11.

Table 9 - Summary of Bulk Planning Investments

IESO Region	Key Recommendation(s) / Hydro One Project Development	Capital Expenditures 2028-2032 ($M)	ISD Ref.
Gatineau Corridor	Station expansions at Dobbin TS and Clarington TS to accommodate the new 230 kV Durham Kawartha Power Line Project	35.5	T-SS-11.01
Northeast Bulk System	• Mississagi–Hanmer 500 kV Reinforcement (new 500 kV connection, autotransformers, switchyard expansion) • North Shore Link (Mississagi–Third Line 230 kV reinforcement, Static Synchronous Compensator (STATCOM) installations) • Wawa–Timmins Powerline (Wawa–Porcupine 230 kV line and station expansions)	440.2	T-SS-11.02 T-SS-11.03 T-SS-11.04
Northern Ontario	Hanmer–Essa Reinforcement: new 500 kV circuit, station expansions, protection upgrades, and series compensation facilities. Reactive support projects including: • Reactors at Lakehead TS • STATCOMs at Mississagi TS and Algoma TS (integrated with North Shore Link, T-SS-11.03) • Reactive support at Mackenzie TS (integrated with Waasigan Project, T-SS-16)	377.5	T-SS-11.05 T-SS-11.06
North of Sudbury	• New Ansonville–Kirkland Lake–Dymond 230 kV transmission line • H9K circuit rebuild	455.0	T-SS-11.07 T-SS-11.08 T-SS-11.09

	• A4/5H corridor rebuild • New single 230 kV transmission line from Hunta SS to Pinard TS, • New double circuit 230 kV from Porcupine TS to Hunta SS. • New single 230 kV circuit from Hunta SS to Kapuskasing TS to enable generation and load growth		T-SS-11.10 T-SS-11.11
South & Central Ontario Includes: - East of Toronto Module - GTA North Module - GTA West Module - Southwest Ontario Module	• Bowmanville SS expansion for Darlington SMR supply • Cherrywood TS reconfiguration for new 500 kV circuits • Bowmanville SS and Hearn SS upgrades for Toronto Third Supply (HVDC) • Northern York Region Reinforcement (Kleinburg area) • Claireville–Kleinburg 500 kV line • Kleinburg station expansion • E8V/E9V transmission upgrade • New Essa TS autotransformer • Milton 500/230 kV TS development • New Guelph North 500/230 kV TS • New St. Thomas 500/230 kV TS • Longwood TS 500 kV Expansion	3,350.3	T-SS-11.12 T-SS-11.13 T-SS-11.14 T-SS-11.15 T-SS-11.16 T-SS-11.17 T-SS-11.18 T-SS-11.19 T-SS-11.20 T-SS-11.21 T-SS-11.22 T-SS-11.23
Eastern Ontario Includes: - Belleville Region Module - Ottawa Region Module	Belleville TS expansion to support the Napanee–Belleville 230 kV transmission reinforcement and reactive compensation facilities • St. Lawrence TS and Merivale TS expansions for new Ottawa supply • Hawthorne TS breaker addition	220.0	T-SS-11.24 T-SS-11.25 T-SS-11.26

Regional Planning

As the largest transmitter in the province, Hydro One plays a key role in Ontario's regional planning process. Regional planning investments address supply and reliability issues at a regional and/or localized level, such as the supply facilities that connect and deliver power to a group of load stations in an area or region. Regional planning generally considers the 115 kV and 230 kV portions of the power system, which supply various parts of the province, but can overlap with bulk system planning and/or distribution system

planning at the interface points or where there may be regional resource options or distribution solutions to address the broader local area for a specific region. The regional planning process is further described in SPF Section 1.2.

As the lead transmitter in 20 out of the 21 planning regions in Ontario, Hydro One is obligated to implement most transmission solutions that are recommended through the Regional Planning process. When a regional plan recommends expansions or reinforcements within a targeted in-service timeline, if the recommended work involves modifications to Hydro One's existing facilities or the construction of new facilities where Hydro One has been recommended as the entity to develop, seek approvals for and/or to build new assets, then Hydro One must incorporate the recommended solution into its investment plans. This includes undertaking the relevant development and scoping work, securing required approvals, acquiring land rights, procuring equipment, and delivering the facilities into service to meet the reliability standards and planning criteria that underpin the identified need.

Table 10 summarizes key investments driven by IESO recommendations through various regional planning studies, which are further described in TSP Section 2.12, T-SS-12.

Table 10 - Summary of Regional Planning Investments

Regional Planning Study	Key Recommendation/Hydro One Project Summary	Capital Expenditures 2028-2032 ($M)	ISD Ref
Windsor-Essex IRRP & RIP (2025)	Build new double-circuit 230 kV transmission line between Lauzon TS and Lakeshore TS (Windsor-Lakeshore Transmission Line Project) with associated station upgrades.	65.0	T-SS-12.01
Northwest - North of Dryden IRRP Addendum (2025)	Construct double-circuit 230 kV circuits from Dryden TS to Ear Falls TS to Red Lake SS with new autotransformers, capacitor installations, and associated transmission upgrades.	104.0	T-SS-12.02
KWCG IRRP (2026)	Construct a new 500/230 kV autotransformer station (Wellington TS) with double-circuit 230 kV connection to Preston TS.	256.5	T-SS-12.03
	Uprate existing 115 kV circuits B5C/B6C, D7F/D9F and F11C/F12C using higher ampacity conductors.		T-SS-12.04
	Upgrade D6V/D7V 230 kV circuits and undertake Detweiler TS reconfiguration to support customer load growth.		T-SS-12.05
Greater Ottawa IRRP & RIP (2025/2026)	Kanata Area Transmission Reinforcement, including new 230 kV supply from Merivale TS, new switching station, and reinforcement of supply to Nepean TS.	304.3	T-SS-12.06
	Provide second 230 kV supply to Orleans TS including transformer and switching facility upgrades.		T-SS-12.07
	Install new 115 kV breaker at Merivale TS to separate M1R and L2M circuits.		T-SS-12.08
St. Lawrence Need Assessment (2026)	Install two new 21.6 Mvar capacitor banks at Brockville TS for voltage support.	8.3	T-SS-12.09
Toronto IRRP & RIP (2025/2026)	Upgrade 115 kV circuits between Manby TS and Riverside Junction to increase transmission capacity.	14.7	T-SS-12.10
Niagara Regional Planning (Ongoing)	Upgrade four 230 kV circuits between Beck GS and Abitibi Junction (approximately 14 km) using higher-capacity conductors.	77.6	T-SS-12.11
	Upgrade 115 kV circuits between Vansickle TS and Louth Junction (approximately 10 km) using higher-capacity conductors.		T-SS-12.12
GTA West IRRP (Ongoing)	Construct new Meadowvale–Hurontario 230 kV line	123.0	T-SS-12.13
	Hurontario SS Reconfiguration		T-SS-12.14

Over the forecast period, Hydro One also plans to undertake the station work required to connect the 230 kV Greenstone Transmission Line, a provincially-designated priority

project. As discussed in section 2.8.7 below, Hydro One expects the line to be owned by an affiliate transmission partnership (ATP) project. The station work for the Greenstone Transmission Line amounts to $95.0M over the 2028-2032 planning period, as further described in TSP Section 2.12, T-SS-10.

2.8.5 LEAVE TO CONSTRUCT APPLICATIONS

Attachment 2 provides a list of investments for which Hydro One expects to initiate a leave to construct (LTC) application under Section 92 of the *Ontario Energy Board Act, 1998* where construction is planned to commence during the 2028-2032 planning period.

A summary of the need, investment description, risk, and costs are provided for each investment in the referenced ISDs (TSP Section 2.12), with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application. As the projects identified in the TSP advance through detailed planning and design, or if the regulatory framework that governs LTC applications is revised, additional projects may be determined to require LTC approval.

2.8.6 IMPACT OF CAPITAL INVESTMENT ON OPERATIONS, MAINTENANCE AND ADMINISTRATION SPENDING

The impact of Hydro One's proposed transmission capital investments on Operations, Maintenance and Administration (OM&A) spending has been assessed on the basis of Hydro One's planning and operating experience. Any impact on total OM&A must be considered in the context of the level of capital work and the fleet of assets that it is intended to renew. Installing new equipment does not yield lower maintenance costs immediately; it takes time for those reductions to materialize. Furthermore, given Hydro One's large asset population and the small portion of assets planned for replacement in the 2028-2032 planning period, maintenance savings resulting from those capital investments are small in relation to the maintenance funding required to maintain the remaining pool of aging assets.

The proposed capital investments are not expected to materially impact OM&A. Hydro One estimates Sustainment OM&A savings resulting from capital investments (once the

new assets are all in-serviced) to be approximately $0.76M per year during the 2028-2032 planning period.

The majority of Hydro One's proposed transmission capital investments either replace poor condition, poor performing and obsolete stations and lines assets or reinforce existing or build new transmission stations and lines.[15] Hydro One's proposed Sustainment OM&A consists of preventive maintenance activities that maintain and collect critical information on new and old transmission stations and lines equipment and facilities and corrective maintenance activities that repair new and old equipment. The Sustainment OM&A activities ensure that transmission assets continue to function safely and as originally designed. Further details can be found in Exhibit E-02-02.

As further discussed above, Hydro One's proposed stations and lines renewal capital investments have been paced to annually replace a small portion of the overall power equipment fleet (i.e. 1-5% of each asset type).[16] As a result, any maintenance savings resulting from those capital investments are small in relation to the funding required to maintain the large pool of aging assets that remain in the fleet. Since the Sustainment OM&A is planned to minimize maintenance on equipment scheduled for replacement, the installation of new equipment does not yield an immediate reduction to the overall maintenance budget. New transmission equipment still requires routine preventive maintenance similar to older equipment, according to the same general frequency and maintenance activities. Hydro One must adhere to various manufacturer maintenance schedules to identify and remedy design issues that manifest in the earlier years of operating new equipment (i.e., warranty related maintenance). For example, rigorous maintenance is required on new transformers during the first one to two years after installation to ensure satisfactory design, with maintenance requirements subsequently levelling off before increasing again closer to their end of life.

[15] General Plant capital investments are not directly related to transmission power system assets and are not discussed here.
[16] 2.4% of the transformer fleet per year, 1.4% of the breaker fleet per year, 3.0% of the protection fleet per year, 4.8% of the conductor fleet per year, 2.7% of the insulator fleet per year and 2.9% of the wood pole fleet per year.

Installing new equipment does not yield lower maintenance costs immediately; it takes time for those reductions to materialize. Rather, new equipment defers the schedule for some of the maintenance work. For example, both new and old transmission lines require helicopter patrols at the same frequency;[17] however, foot patrols, which are costly, are scheduled every 12 years on new lines, and alternating foot patrols and detailed helicopter inspections are carried out every six years on older lines. Considering that lines capital investments are forecast to refurbish 4.8% of the fleet each year, the corresponding OM&A savings due to the difference in maintenance work is $0.1M.[18]

New equipment may result in short-term Sustainment OM&A savings due to lower unplanned corrective maintenance, however, these savings are not significant in relation to funding needed for the large pool of older equipment. As shown in Table 11 below, over the 2021-2025 period, 88% of the corrective defects occurred on the older portion of the major power system equipment (e.g., transformers, breakers, and lines) and 93% of the corrective expenditures were spent to fix those defects. Table 11 also illustrates that new equipment does incur corrective maintenance costs, primarily due to external factors, such as extreme weather, motor vehicle collisions, and wildlife). In this regard, Sustainment OM&A activities are required to correct and/or mitigate equipment damage. Since the proposed stations and lines renewal capital investments have been paced to annually replace a small portion of the overall power equipment fleet (i.e. 1-5% of each asset type)[19] the corresponding corrective maintenance savings are expected to be approximately $0.66M per year.[20]

[17] Three years for steel lines and every two years for wood lines.
[18] Approximately $1.8M is estimated to be saved over 25 years due to detailed helicopter patrols on new lines, resulting in annual savings of $0.1M.
[19] 2.4% of the transformer fleet per year, 1.4% of the breaker fleet per year and 5.2% of the conductor fleet per year.
[20] For Lines, during 2021-2025 the yearly corrective cost per km was $253 for old lines and $43 for new lines. Hydro One plans to replace 1,369 km of poor condition lines, resulting in annual savings of $0.35M per year when these lines are in-serviced. For transformers, during 2021-2025 the corrective cost per unit was $6,309 for new units and $18,624 for old units. Hydro One plans to replace about 24 units per year, resulting in annual savings of $0.21M per year when these units are in-serviced. For breakers, during 2021-2025 the corrective cost per unit was $564 for new units and $2041 for old units. Hydro One plans to replace about 86 units per year, resulting in annual savings of $0.10M per year when these units are in-serviced.

Table 11 - Corrective Maintenance – Old vs. New Equipment (2021-2025)

	Transformers		Breakers		Lines	
	New[21]	Old	New	Old	New	Old
Equipment Age	27%	73%	26%	74%	27%	73%
Corrective Defects (%)	16%	84%	9%	91%	5%	95%
Corrective Budget (%)	11%	89%	9%	91%	6%	94%

As Hydro One replaces equipment with newer technology and improved designs, there are certain savings in corrective maintenance costs, primarily resulting from equipment that (i) is less prone to breakdowns than the older technology (e.g., new sulfur hexafluoride (SF_6) breakers have lower leakage rates than first generation breakers); (ii) does not require certain types of traditional maintenance (e.g., new microprocessor-based relays, which have lower average preventative maintenance costs per unit as a result of longer maintenance cycles and self-monitoring capabilities, and new transformers with oil monitoring that eliminates manual oil inspections); or (iii) requires less intrusive maintenance that is often completed at the equipment's mid-life (e.g., new transformers that utilize vacuum tap changers in place of oil-filled units, eliminating the need for future internal preventative maintenance). However, those savings are offset by new and additional compliance requirements that apply to certain transmission assets (both new and old equipment). For example, while new microprocessor-based relays have lower average preventative maintenance costs per unit, these savings are offset by (i) increasing maintenance requirements for protection relay systems due to NERC standards,[22] and (ii) an increase in the number of protection systems due to NPCC standards[23] that require duplicated protection schemes to provide redundancy.

[21] New equipment was determined as follows: For Lines, 25 years was chosen because it is the age at which condition assessments are initiated. Similarly, for transformers and breakers 10 years was used.

[22] North American Electric Reliability Corporation (NERC) Reliability Standards PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance), to which Hydro One will fully transition by 2028, and PRC-012-2 (Remedial Action Schemes), which came into effect on January 1, 2021.

[23] Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directories #4 (System Protection Criteria) and #7 (Remedial Action Schemes)

2.8.7 EXCLUSION OF CAPITAL EXPENDITURES FOR NEW PARTNERSHIPS

Hydro One has excluded capital expenditures over the 2028-2032 planning period related to ATP investments that are expected to be fully or partially owned by and included in the rate base of new affiliated transmission-licensed partnerships and will not form part of Hydro One's transmission rate base.

These ATP investments are typically new transmission lines, designated as network facilities, which are expected to exceed $100M. Typically these investments are initiated based on recommendations from bulk planning or regional planning reports, direction from the IESO, or an Order in Council or directive from a Minister of the Government of Ontario for the development or construction of a transmission project.

The capital expenditures associated with the station facilities required to connect the new ATP transmission lines are detailed in the ISDs included in TSP Section 2.12. These expenditures are tracked in the ATP Regulatory Account approved by the OEB in October 2021 (EB-2021-0169). While these station assets will form part of Hydro One's transmission rate base, as summarized in Table 12, the ATP transmission lines themselves are expected to be owned by separate licensed transmitters and are therefore not included in this application.

Table 12 - Summary of ATP Line Projects with Associated Station Work

ATP Line Project (excluded from capital plan)	ISD for Associated Station Work
Welland-Thorold Powerline Project	T-SA-11
Chatham to Lakeshore Transmission Line	T-SS-09
St. Clair Transmission Line (formerly referred to as the Lambton to Chatham Transmission Line)	T-SS-09
Greenstone Transmission line	T-SS-10
Windsor to Lakeshore Transformer Station Line	T-SS-11
North Shore Link	T-SS-11
Northeast Power Line	T-SS-11
Durham Kawartha Power Line	T-SS-11

Wawa Timmis Power Line	T-SS-11
Hanmer – Essa new line	T-SS-11
New Ansonville–Kirkland Lake–Dymond transmission line	T-SS-11
New single transmission line from Hunta SS to Pinard TS	T-SS-11
New double circuit from Porcupine TS to Hunta SS	T-SS-11
New single circuit from Hunta SS to Kapuskasing TS	T-SS-11
New line from Bowmanville to Cherrywood	T-SS-11
New double circuit extension from Belleville TS to Napanee TS (X21/X22)	T-SS-11
New double circuit from Merivale TS to St Lawrence TS	T-SS-11
Wellington to Preston Transmission Station Line	T-SS-12
North of Dryden Transmission Reinforcement (Red Lake Transmission Line)	T-SS-12
Waasigan Transmission Line	T-SS-16

When ATP projects not known at the time of this filing arise as a result of legislation, regulation, codes, licenses, reports, studies, assessments, letters, and similar instruments/documents issued by governmental authorities, and where Hydro One is expected to undertake the related work as lead transmitter in regional planning and, as the identified or default transmitter in bulk planning, receives direction to develop and construct, the revenue requirement impact associated with the portion that will form part of Hydro One's rate base (typically station expenditures) will be recorded in the Externally Driven Transmission Projects Variance Account (see Exhibit G-01-03).

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SECTION 2.8 – ATTACHMENT 1 – APPENDIX 2-AA – CAPITAL PROJECTS FOR TRANSMISSION

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SECTION 2.8 – ATTACHMENT 2 – LEAVE TO CONSTRUCT APPLICATIONS

ISD Ref.	Investment Name
T-SA-07.01	West Toronto Transmission Line Relocation
T-SA-10	Build Leamington Area Transformer Stations and Line
T-SA-11.03	Connect North Whitby MTS
T-SA-11.09	Brant TS: New 230 DESN
T-SA-11.11	Build New Tillsonburg Area DESN
T-SA-11.12	Build New Yarmouth Centre DESN
T-SA-11.15	New Coatsworth DESN 1 and 2 and Tap Connection
T-SS-10	Greenstone Transmission Line Project – Station Work
T-SS-11.06	Sudbury Barrie Transmission Line - Station
T-SS-11.07	New 230 kV Line: Dymond x Kirkland Lake x Ansonville - Station
T-SS-11.08	H9K Reconductor
T-SS-11.09	A4H or A5H Reconductor
T-SS-11.10; T-SS-11.11	230kV station expansion at Porcupine TS, Hunta SS and Pinard TS and 230kV station expansion at Kapuskasing TS Hunta SS
T-SS-11.13	Build 500 kV Line from Bowmanville SS to GTA East – Station
T-SS-11.15	Transmission Reinforcement for Northern York Region
T-SS-11.16; T-SS-11.17	New Claireville x Kleinburg 500 kV – Line and New Claireville x Kleinburg 500 kV Station
T-SS-11.18	Orangeville x Barrie Reconductor (E8V/E9V 230kV Transmission Line Upgrade)
T-SS-11.20	Milton TS Expansion
T-SS-11.21; T-SS-11.23	Guelph North TS Development and Longwood TS 500kV Expansion
T-SS-11.24	Napanee–Belleville 230kV Transmission Reinforcement
T-SS-11.25	New 230kV Line: St. Lawrence TS x Merivale TS - Station

T-SS-12.01	Windsor Lakeshore Transmission Line – Station Work
T-SS-12.02	North of Dryden Transmission Reinforcement (Red Lake Transmission Project) – Station Work
T-SS-12.03	Wellington TS: Build new 500kV/230kV Station
T-SS-12.05	D6V/D7V - Upgrade circuits out of Detweiler
T-SS-12.06	Kanata Area Transmission Reinforcement
T-SS-12.11	Uprate 230 kV QFW Circuits – Beck x Abitibi Junction
T-SS-12.12	Uprate 115kV D9HS/D10S
T-SS-12.13; T-SS-12.14	Meadowvale to Hurontario Transmission Line and Hurontario SS Reconfiguration - Station

SECTION 2.9 – TSP – CAPITAL EXPENDITURE VARIANCES

2.9.1 INTRODUCTION

This Exhibit describes variances between the OEB approved 2023-2027 transmission capital expenditures and actual and forecast expenditures over that period. It also explains the variances for each OEB category, namely System Access, System Renewal and System Service. Variances pertaining to General Plant capital expenditures are discussed in GSP Section 4.9.

The individual project and program variances described in this section use Hydro One's December 2022 capital expenditure and ISA forecasts as the basis for the variance comparison. These forecasts reflect the OEB-approved envelopes (the Plan) in accordance with the Settlement Proposal in Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110).[1]

Variance explanations for each material investment, including with respect to work volumes, are provided in the Investment Summary Documents included in TSP Section 2.12. In addition, Hydro One has prepared detailed summaries for material investments with significant variances relative to the Plan in TSP Section 2.9, Attachment 2. Additional variance analyses can be found in Hydro One's 2023-2025 Capital Performance Reports (see TSP Section 2.9 Attachments 3-5).

For variance discussion pertaining to the Transmission OM&A, refer to Exhibit E-02-01.

[1] In EB-2021-0110, the OEB approved multi-year capital expenditure and ISA envelopes, by capital category, for the 2023 to 2027 period (Decision and Order, November 29, 2022, Schedule A, pp.254-255 and pp.257-258). In December 2022, Hydro One allocated the OEB-approved funding envelope for 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.

2.9.2 HISTORICAL CAPITAL EXPENDITURES TRENDS AND VARIANCES

2.9.2.1 OVERVIEW

Hydro One has 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 costs. Hydro One Transmission's historic and forecast capital expenditures relative to OEB-approved amounts are summarized in Table 1.

1

Table 1 - Hydro One Transmission - Historical and Bridge Years Capital Expenditure Summary

OEB Category	Historical (OEB Approved and Actual / Forecast) [2]												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	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
System Access	83.6	62.6	-25.0	74.6	106.9	43.2	63.0	148.9	136.4	38.4	204.4	432.3	52.8	253.0	379.4	312.3	775.8	148.4%
System Renewal	1,103.4	971.6	-11.9	1,150.6	1,209.7	5.1	1,172.4	1,103.7	-5.9	1,196.5	1,087.1	-9.1	1,184.0	926.6	-21.7	5,806.9	5,298.6	-8.8%
System Service	95.6	133.9	40.1	107.0	125.7	17.6	90.3	141.0	56.2	98.0	459.5	368.7	94.8	1021.3	977.5	485.7	1,881.5	287.4%
General Plant[3]	143.7	146.3	1.8	121.4	134.3	10.6	111.8	111.0	-0.7	113.4	86.8	-23.4	102.8	82.9	-19.3	593.1	561.3	-5.4%
Subtotal	**1,426.3**	**1,314.4**	**-7.8**	**1,453.6**	**1,576.5**	**8.5**	**1,437.4**	**1,504.6**	**4.7**	**1,446.3**	**1,837.8**	**27.1**	**1,434.4**	**2,283.9**	**59.2**	**7,198.0**	**8,517.2**	**18.3%**
Productivity[4]	-64.2	-	-	-64.2	-	-	-64.2	-	-	-64.2	-	-	-64.2	-	-	-321.0	-	-
Total	**1,362.1**	**1,314.4**	**-3.5**	**1,389.4**	**1,576.5**	**13.5**	**1,373.3**	**1,504.6**	**9.6**	**1,382.1**	**1,837.8**	**33.0**	**1,370.2**	**2,283.9**	**66.7**	**6,877.0**	**8,517.2**	**23.8**
Prepaid Related to Cloud (Transmission)[3]	-	-	-	-	-	-	-	10.3	-	-	48.3	-	-	31.2	-	-	89.7	-

[2] 2023-2027 actuals exclude new transmission line facilities designated as Affiliate Transmission Projects. Hydro One's application to establish a Deferral Account for these Affiliate Transmission Projects was approved in October of 2021 (EB-2021-0169). Further information may be found in TSP Section 2.8.
[3] Details on General Plant expenditures and Prepaid Related to Cloud, are found in Exhibit B-04-01 General Plant System Plan (GSP).
[4] Productivity represents commitments made during the 2020-2022 transmission rate application for 2022 that are sustained through the 2023-2027 period. Further productivity for Hydro One's most recent transmission rate filing (EB-2021-0110) are applied to revenue requirement via productivity stretch factors, as described within the SPF Section 1.4.

Witness: Scott Vicary; Donna Jablonsky; Mark Brodie

As outlined in Table 1, total capital expenditures over the five-year historic and bridge period are forecast to be approximately 23.8% above the OEB-approved envelope. Across the period, almost all spending above the approved amounts is due to the increase in work arising in response to IESO recommendations from regional and bulk planning processes, and from Orders in Council and Ministerial directives requiring Hydro One to implement particular projects. These emergent capital investments are in addition to the externally-driven work that was included in the OEB-approved settlement proposal for the 2023-2027 period. When the additional externally-driven work is excluded, Hydro One's cumulative Transmission capital expenditures are forecast to be under the OEB-approved envelope by 0.4% ($24.4M). This is illustrated in Figure 1 below.

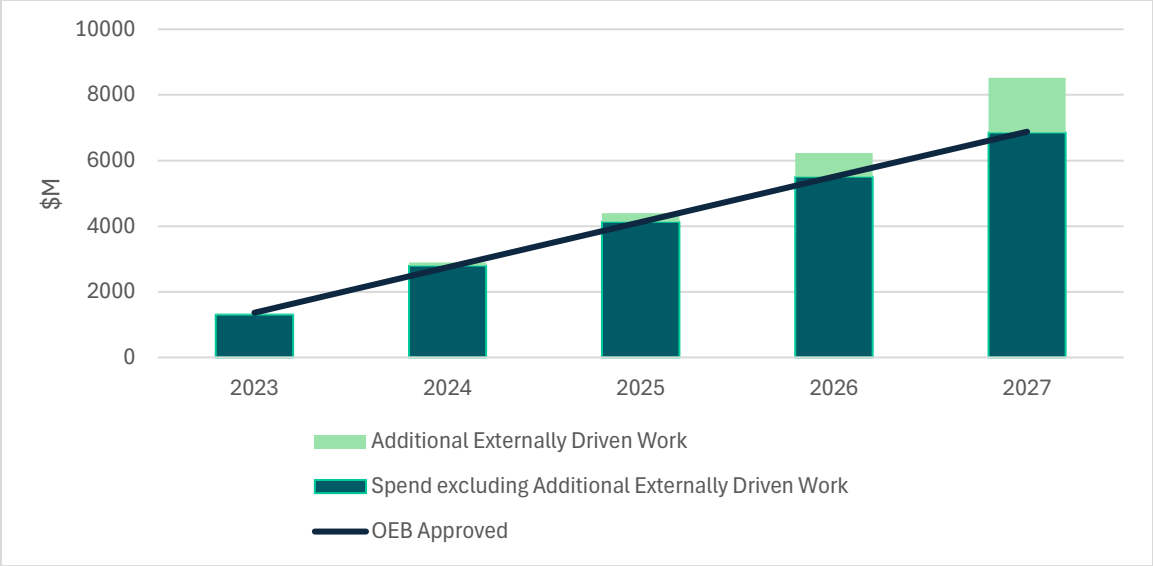

Figure 1: 2023-2027 Cumulative Transmission Capital Expenditure

Over the 2023-2027 period, Hydro One has experienced a material and unanticipated increase in non-discretionary customer connections, transmission system expansion requirements driven by IESO regional and bulk system planning, and the addition of priority transmission projects. Since 2023, the number of transmission connection requests has doubled to approximately 200 per year, reflecting growing demand for access to Ontario's electricity system. In addition, as a result of ongoing regional and bulk system planning, multiple investments were either expanded in scope or added to the

work program. The result was a 148% increase in System Access investments and a 287% increase in System Service investments to meet the company's obligations in respect of the province's system planning, including responsiveness to IESO processes, Orders in Council, directives from the Minister of Energy and Mines, Transmission Licence conditions, as well as compliance with the Transmission System Code. Together, investments in System Access and System Service are expected to comprise approximately 31% of actual transmission capital investments over the historical and bridge period, relative to approximately 11% in the Plan.

Growth in non-discretionary work, together with persistent and elevated inflation and market forces as described in SPF Section 1.8, affected both the type and volume of work Hydro One could complete within its OEB-approved capital funding. To manage these pressures, Hydro One directed available funding toward non-discretionary, externally-driven, and high-priority investments. Consistent with the prioritization approach described in SPF Section 1.7, Hydro One focused resources on investments to mitigate potential impacts and maintain customer and system outcomes, resulting in the deferral of necessary work in categories where the pace and scheduling is more flexible. Consequently, overall System Renewal investment was reduced during the 2023-2027 period.

Figure 2 shows the proportions of capital spending by category in the 2023-2027 OEB-approved settlement proposal relative to Hydro One's actual/forecast values. As can be seen, investments in the System Renewal category dropped from a planned level of 81% to 62% of total transmission capital expenditures, due to the corresponding increases in System Access and System Service spending. The specific impacts of deferred renewal work on historical transmission capital investments, and the associated risks, are described below where relevant.

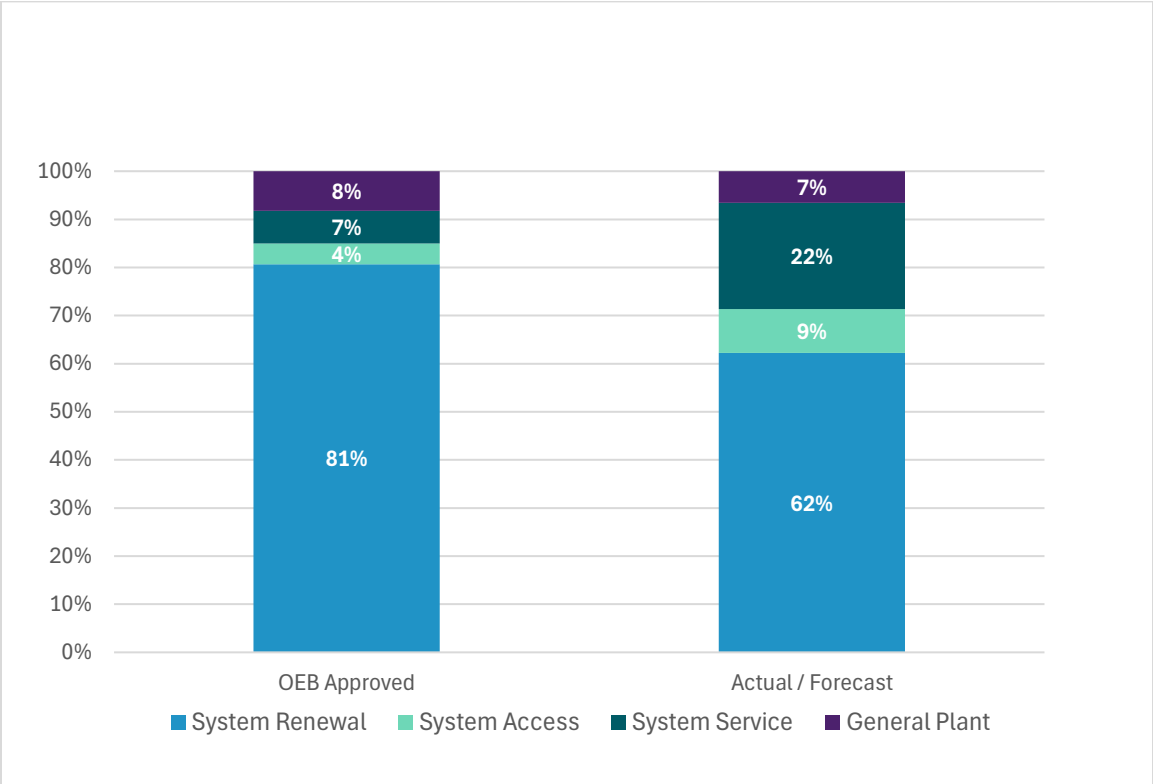

Figure 2: 2023-2027 Transmission Capital Expenditure Proportional Spend - Reprioritized Transmission Capital Expenditures[5]

Hydro One strives to make optimal investments within the funding available while maximizing risk mitigation. In-year execution is guided by 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 incomplete work deferred and reassessed through the planning cycle.

[5] Settlement values exclude progressive productivity.

While work optimization is necessary and allows the company to adapt to changing demands and cost pressures, the deferral of investments will eventually result in a growing population of assets in poor and deteriorating condition. Restoring a prudent pace of planned investment is therefore critical to mitigating long-term system risk while maintaining the safe and reliable operation of the system.

At the same time, Hydro One has actively pursued cost-mitigation opportunities. This has included rigorous review of active projects to identify cost efficiencies and mitigate variances. These efforts have resulted in forecast cost reductions across more than 60 projects. For example, the Bruce A Transformer Station 500 kV Switchyard Replacement project was optimized through schedule acceleration, reducing system exposure to nuclear outages and both contingency and commissioning costs, lowering the overall project cost by approximately $30.0M. Similarly, the Richview x Manby Transmission Reinforcement project realized approximately $12.0M in cost savings due to design optimization of the associated community trail, efficiencies in construction and effective risk management. Details on project specific variances and associated cost saving efforts are set out in the OEB category summaries below and TSP Section 2.9 Attachment 2.

Importantly, Hydro One continues to deliver its capital program with a strong emphasis on safety. Hydro One maintains a recordable injury rate well below 1.0, as discussed in TSP Section 2.5, which is considered industry-leading among peer utilities. This performance reflects Hydro One's embedded safety culture and its commitment to operational excellence.

Sections 2.9.2.2, 2.9.2.3, and 2.9.2.4 summarize the capital spending and variances within the System Access, System Renewal, and System Service categories, respectively.

2.9.2.2 SYSTEM ACCESS

Over the 2023-2027 period, System Access investments are forecast to be $463.5M (148.4%) above planned spending levels, primarily due to significant demand for new customer connections, local area supply needs, and an influx of externally driven work. The values shown reflect the investment cost net of the required capital contributions as

calculated by the economic evaluation methodology in accordance with Hydro One's OEB Approved Transmission Connection Procedures. Table 2 presents historical capital expenditures for System Access.

Table 2 - Hydro One Transmission - Historical and Bridge System Access

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	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
System Access	83.6	62.6	-25.0	74.6	106.9	43.2	63.0	148.9	136.4	38.4	204.4	432.3	52.8	253.0	379.4	312.3	775.8	148.4%

System Access investments are forecasted to exceed OEB-approved amounts for various reasons, including the following:

- **New load customer connections and new local area supply needs:** Several material projects emerged after the 2023-2027 capital expenditure forecast was developed and, as a result, were not included in that forecast. Strong demand for new connections resulted in Hydro One enabling approximately 2,200 MW over the 2023-2027 period, 29% above its original plan of 1,700 MW. This category of work increased materially and exceeded historical volumes for similar investments. Five particular projects account for approximately $190M of unanticipated spend over the 2023-2027 period:
    - The new 230 kV Crowland TS is required as part of the Welland Thorold Power Line project to supply the increasing load forecasted for the area. This investment is further discussed in TSP Section 2.12, T-SA-11.
    - Wallaceburg TS Conversion includes converting the station from 115 kV to 230 kV to facilitate the connection of the new 230 kV St. Clair Transmission Line by repurposing a 115 kV transmission line corridor that was slated for end of life refurbishment. This investment's expenditures are included in TSP Section 2.12, T-SA-11.

- Energize Essex County Project involves constructing a new station and an approximately 27 km 230 kV double circuit transmission line to support load restoration and associated 230 kV switching facilities, as recommended in the 2025 Windsor-Essex IRRP. This investment is further described in TSP Section 2.12, T-SA-10.
- Belleville TS: Build 75/125 MVA, 230/44 kV DESN to provide additional capacity as requested by LDC customers in the region of Belleville in eastern Ontario as the projected load exceeded the current capacity available for the existing Belleville TS DESN. This investment is forecast to be placed in-service in 2026.
- Markham TS #5 New DESN is required to meet LDC forecasted customer load growth in the City of Markham. This investment is further discussed in TSP Section 2.12, T-SA-11.

- **New Externally Driven Projects:** An influx of externally driven work accounts for approximately $260M of the projected variance during the period. This is primarily a result of the following investments resulting from government policies and initiatives, which account for approximately $235M of unanticipated spend.
    - Centennial TS: The customer has selected the province of Ontario and the City of St Thomas in which to invest $7.0B in a large-scale EV battery manufacturing facility. The proposed connection plan to supply the customer facility consists of building two new 230 kV double-circuit transmission line taps and a new 230/27.6kV transmission station. This investment's expenditures are included in TSP Section 2.12, T-SA-12.
    - Holt Switching Station SMR Connection is required to execute the connection of the OPG Small Modular Reactor (SMR) Unit 1.

Together, the projects listed above account for approximately $425M (about 91%) of the total System Access variance over the historical and bridge period. As these and other System Access investments are non-discretionary, Hydro One has limited ability to manage these new investments through offsetting reductions within the System Access category.

Witness: Scott Vicary; Donna Jablonsky; Mark Brodie

2.9.2.3 SYSTEM RENEWAL

Over the 2023-2027 period, System Renewal investments are forecasted to be $508.3M (8.8%) below planned spending levels, primarily driven by capital reprioritization to the System Access and System Service categories to facilitate new customer connections, local area supply needs and system upgrades (as described in sections 2.9.2.2 and 2.9.2.4). These reductions were partially offset by increased expenditures in other investments. In addition, there has been approximately $230M of externally driven work in the System Renewal category, primarily related to the Waasigan Transmission Line (station portion)[6] which will enable the required increase in supply capacity to support future load growth and maintain reliability for the Northwest region in the long-term as identified by the IESO in its Integrated Regional Resource Plan (IRRP).

Table 3 presents historical capital expenditures for System Renewal.

Table 3 - Hydro One Transmission - 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	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
System Renewal	1,103.4	971.6	-11.9	1,150.6	1,209.7	5.1	1,172.4	1,103.7	-5.9	1,196.5	1,087.1	-9.1	1,184.0	926.6	-21.7	5,806.9	5,298.6	-8.8%

Relative to the spending set out in the OEB-approved Settlement Proposal, System Renewal expenditures were primarily reduced in the following investments:

- **Line Refurbishments:** Thirteen material transmission line refurbishment projects were deferred out of the 2023-2027 period, including the refurbishments of T33E Almonte TS x Oshawa North Junction, D2/3H Hunta SS x Abitibi Canyon Junction, T25B Clarington TS x Pancake Junction, E8V/E9V Orangeville TS x Essa

[6] In the historic and bridge period, the Waasigan Transmission Line (station portion) was included in the System Renewal category. In the 2028-2032 period it is recorded in the System Service category.

Junction, and L22H Easton Junction x Hinchinbrook. These five projects account for approximately $415M of the System Renewal negative spend variance. Further details are provided in TSP Section 2.12, ISD T-SR-13, Transmission Line Renewal.

- **Defective Insulator Replacement:** Forecast replacements for the Transmission Line Insulator Replacement program have been reduced by 22% for 2023-2027, which was also impacted by system outage constraints and cancellations. This program accounts for approximately $106M of the System Renewal negative spending variance. Approximately 63% of identified defective porcelain insulators have been addressed by the end of 2025 and Hydro One expects 73% to be addressed prior to 2028. The remaining defective porcelain insulators are planned to be replaced by year-end 2032. Replacement has been prioritized for locations posing a higher public safety risk. Further details are provided in TSP Section 2.12, T-SR-08, Transmission Line Insulator Replacement.
- **Steel Structure Coating Program:** Steel Structure Coating program expenditures were reduced during the 2023-2027 period. This investment is driven by the economic benefits that result from extending the service life of steel transmission structures, reducing overall life cycle cost, as outlined in TSP Section 2.12, T-SR-05, Steel Structure Coating Program. Over the 2023-2027 period, it is expected that 65% of the post-settlement planned investments within this program will be deferred, accounting for approximately $57M of the System Renewal negative spend variance.

As described in Section 2.9.2.1 above, Hydro One deferred work during the 2023-2027 period based on assessed risks to safety, environment and reliability. The reduced spending in these areas helped Hydro One to accommodate the unanticipated increase in mandated customer connections, and transmission system expansion requirements, as well as the persistent increase in input costs described in SPF Section 1.8, which have significantly increased the cost of key electrical equipment and materials. One notable example of the impact of these cost pressures is the Bruce A 500 kV Switchyard Replacement, which involves the replacement of breakers, autotransformers, protection and automation systems, and telecommunications facilities. Market conditions impacted

the execution of the project as commodity costs increased amid rising inflationary pressure. In addition, commodity costs for key inputs such as copper, steel, and aluminium increased significantly, contributing to higher warranty, security, shipping, and contingency costs experienced on the project. Efforts to accelerate the project helped to partially offset these increases and led to approximately $30M in cost reductions due to reduced contingency and commissioning costs.

2.9.2.4 SYSTEM SERVICE

Over the 2023-2027 period, System Service investments are forecasted to be $1,395.8M (287.4%) above planned spending levels largely due to a significant increase in externally driven work. Table 4 below presents historical capital expenditures for System Service.

Table 4 - Hydro One Transmission - Historical and Bridge System Service

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	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
System Service	95.6	133.9	40.1	107.0	125.7	17.6	90.3	141.0	56.2	98.0	459.5	368.7	94.8	1021.3	977.5	485.7	1,881.5	287.4%

System Service expenditures are forecast to be higher primarily due to the need for externally-driven investments arising from IESO-led regional and bulk planning processes, as well as Orders in Council, Ministerial Directives and Transmission Licence conditions. The total variance attributable to externally driven work is $1,175M, which represents 84% of the overall System Service variance.

The following large externally-driven projects account for approximately $1,010M of the System Service spend variance:

- **Mississagi x Hanmer Reinforcement (station portion) and Mississagi x Third Line Reinforcement (station portion)** where the IESO's *Need for Northeast Bulk*

System Reinforcement report recommended construction of these new transmission lines due to economic development in mining and manufacturing in Northern Ontario. These two projects alone account for approximately $600M of unanticipated spend over the 2023-2027 period. This investment is further discussed in TSP Section 2.12, T-SS-11.

- **Bowmanville SS Expansion** which was recommended by the IESO as part of their report "Connection Approach for Ontario's First Small Modular Nuclear Reactors (2024)" in response to the Province's "Powering Ontario's Growth" report to relieve current transmission congestion and accommodate bulk power transfers on the corridor, including the enablement of two new double-circuit 500 kV transmission lines and up to 1,200 MW of generation from the connections of four Small Modular Reactor (SMR) units. The IESO subsequently identified the Bowmanville expansion as an Early Action within the South and Central Bulk Plan. This investment is further discussed in TSP Section 2.12, T-SS-11.
- **St. Clair Transmission Line (station portion) and Longwood x Lakeshore Transmission Line (station portion)** which involve constructing the necessary station expansion and connection work at terminal networks stations to facilitate the connection of new transmission circuits to increase the transfer capability of the bulk transmission system east of Chatham and improve the deliverability of resources in the Lambton-Sarnia area for intra-zonal and provincial supply. This investment is further described in TSP Section 2.12, T-SS-09.
- **Durham Kawartha Power Line (station portion)** is required as part of the Durham Kawartha Power Line project to supply the increasing load forecasted for the area. This investment is further described in TSP Section 2.12, T-SS-11.
- **Greenstone Transmission Line Project** where Hydro One is the designated transmitter for development and construction of the station work associated with a new 230 kV circuit in Northern Ontario. This investment is further described in TSP Section 2.12, T-SS-10.
- **Wellington TS Project** involves the development of a new 500 kV/230 kV autotransformer station to accommodate a new double circuit 230 kV line between Puslinch and Cambridge to supply increasing load forecasted in the Kitchener-

Waterloo-Cambridge-Guelph region. This investment is further described in TSP Section 2.12, T-SS-12.

- **115 kV Upgrades (B5/6C, D7/9F, F11/12C)** to upgrade the existing circuit with higher ampacity conductors. This investment is further described in TSP Section 2.12, T-SS-12.
- **E8V/E9V 230 kV Transmission Line Upgrade** to upgrade existing circuit between Orangeville and Barrie to enable new load connections in the region. This investment is further described in TSP Section 2.12, T-SS-11.
- **Hanmer x Essa 500 kV Circuit (station portion)** is required as part of the Hanmer x Essa 500 kV Circuit project to enable both demand growth and resource procurement in Northern Ontario, while maintaining system reliability. This investment is further described in TSP Section 2.12, T-SS-11.

As the above investments are non-discretionary, Hydro One has limited ability to manage these new investments through offsetting reductions in the System Service category. Aside from the externally driven work, multiple System Service investments were added during the 2023-2027 period to address emerging needs, or increased in scope and cost. The following six investments account for approximately $110M of the System Service spend variance:

- **Orleans TS: Provide second 230 kV supply:** The Orleans area in Ottawa is experiencing significant growth, which is expected to continue in the future. This project involves constructing a new 230 kV circuit to meet the forecasted load growth. Additionally, the project will convert Orleans TS into a dual 230 kV supply station, providing extra transformation capacity. This project experienced increased costs as the scope was changed to construct a new line and acquire easement rather than modify existing towers to avoid multiple extended outages, meet the load growth in the area, and reduce ongoing maintenance. This investment is further described in TSP Section 2.12, T-SS-12.
- **Richview Manby Transmission Reinforcement**: Hydro One experienced increased costs as the project moved from planning to execution, refining the work plan and changing the construction execution methods to minimize disruption of vegetation and community green space along the corridor to align with public

needs determined through the Environmental Assessment process. Even with these adjustments, the investment was completed well below the AACE Class 3 estimate nominal value, realizing approximately $12M in total savings through design optimization of the community trail, efficiencies in construction and effective risk management. This investment is further discussed in TSP Section 2.12, T-SS-06.

- **M31W - Reinforce Buchanan x St Thomas Line Tap Point**: This new investment emerged during the 2023-2027 period in response to increased load growth forecasts. The work involves rebuilding the M31W circuit between Buchanan TS and the new St. Thomas Line tap point with higher capacity conductor on double circuit towers, strung with one circuit but capable of accommodating a second circuit in the future, when needed, per the IESO's recommendation in the Central-West Bulk Plan.
- **Transmission Reinforcement for Northern York Region:** This new investment, identified as part of the IESO's South and Central Bulk Plan, involves the construction of a new auto-transformer station in Kleinburg, with approximately 6 km of double circuit 230 kV transmission line from Kleinburg to Kirby area in existing transmission corridor. This investment is further described in TSP Section 2.12, T-SS-11.
- **Chatham SS - Add Station Service**: This project was required due to the incorporation of the Chatham SS x Lakeshore TS circuits. The project experienced higher than expected contractor and procurement costs and was also accelerated.
- **Pickle Lake SS - Shunt Reactor Installation**: This new investment emerged due to operational challenges concerning the 115 kV E1C transmission line and to maintain system adequacy and meet forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas. The work involves the installation of additional reactive control devices.

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SECTION 2.9 – ATTACHMENT 1 – APPENDIX 2-AB: CAPITAL EXPENDITURES SUMMARY

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SECTION 2.9 – ATTACHMENT 2 – CAPITAL ACCOMPLISHMENTS AND VARIANCES

1.0 OVERVIEW

This attachment summarizes the supplemental capital performance evidence that Hydro One has provided for the TSP in respect of the 2023-2027 period, which includes:

- Detailed variance reviews for material investments that are currently in execution or have been completed and have the largest project total variances relative to the Plan[1] (TSP Section 2.9, Attachments 2A – 2R);
- Detailed variance information for the Hawthorne to Merivale Reconductoring Project (EB-2020-0265, TSP Section 2.9, Attachments 2S and 2T);
- Detailed variance information for the Richview to Trafalgar Reconductoring Project (EB-2021-0136, TSP Section 2.9, Attachments 2U);
- Annual Capital Performance Reports for 2023, 2024, and 2025 (TSP Section 2.9, Attachments 3, 4, and 5)[2];
- Material investment variance descriptions within each Transmission Investment Summary Document (TSP Section 2.12).

During the 2023-2027 period, Hydro One continued to improve the efficiency and effectiveness of its capital delivery program while managing a larger and more complex capital portfolio. As discussed below, Hydro One achieved measurable improvements in portfolio-level cost and schedule performance, with a greater proportion of projects performing below the AACE Class 3 upper bound and within six months of their original in-service dates.

[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] Following the publication of the 2023 and 2024 Capital Performance Reports (CPRs), Hydro One updated the OEB category mapping for a limited number of investments. As a result, certain OEB category-level actual expenditures and in-service additions reported in Table 1 of the 2023 and 2024 CPRs differ from the updated amounts presented in this Application.

2.0 CAPITAL PERFORMANCE OVERVIEW

At Hydro One, transmission projects are governed with a focus on adherence to the total project budget. Execution of transmission projects follow the Project Delivery Model, discussed in TSP Section 2.11.

As projects move from early-stage planning, project requirements become more clearly defined. Based on a comparison of the Plan project total forecasts with the latest forecasts in this Application, scope additions and changes arising from the planning, development and execution of projects were the main contributing factors to variances over the 2023-2027 period. Significant escalation in the cost of key equipment, which exceeded overall inflation, also contributed to project variances as discussed in SPF Section 1.8.

Hydro One has actively pursued cost-mitigation opportunities during the 2023-2027 period to help offset the cost pressures from scope increases and equipment cost escalation. These efforts include undertaking a rigorous review of active projects to identify cost efficiencies and mitigate variances. These efforts have resulted in actual and forecast cost reductions across more than 60 projects.

In addition to project-specific cost mitigation, Hydro One continued to increase the efficiency with which it delivered the capital work program over the 2023-2027 period. These improvements were an outcome of several initiatives the company undertook to improve its already robust capital delivery systems. TSP Section 2.11.7 details eight such initiatives, including enhancements to the Transmission Project Delivery Model; in-field productivity improvements; Early Contractor Involvement for large, higher-impact projects; technology improvements; and improvements to estimating and resource planning.

Despite the overall cost and work volume pressures during the 2023-2027 period, Hydro One has generally achieved strong cost and schedule performance for transmission investments with execution-level estimates (AACE Class 3).[3]

[3] Based on transmission capital power system projects over $10M in execution phase.

As shown in Figures 1 and 2, over the 2023-2026 period there have been significant performance improvements across the active transmission capital projects portfolio.

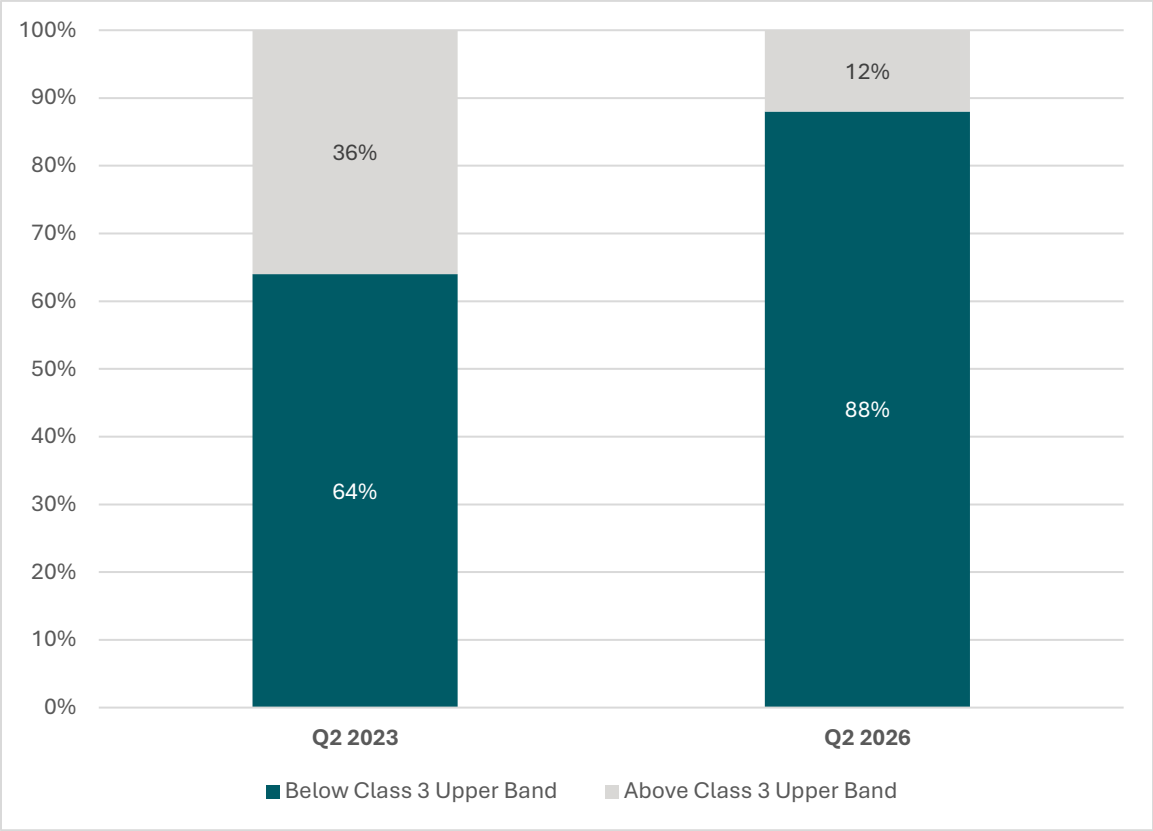

Figure 1: Cost Performance of the Capital Projects Portfolio (Q2 2026 vs Q2 2023)

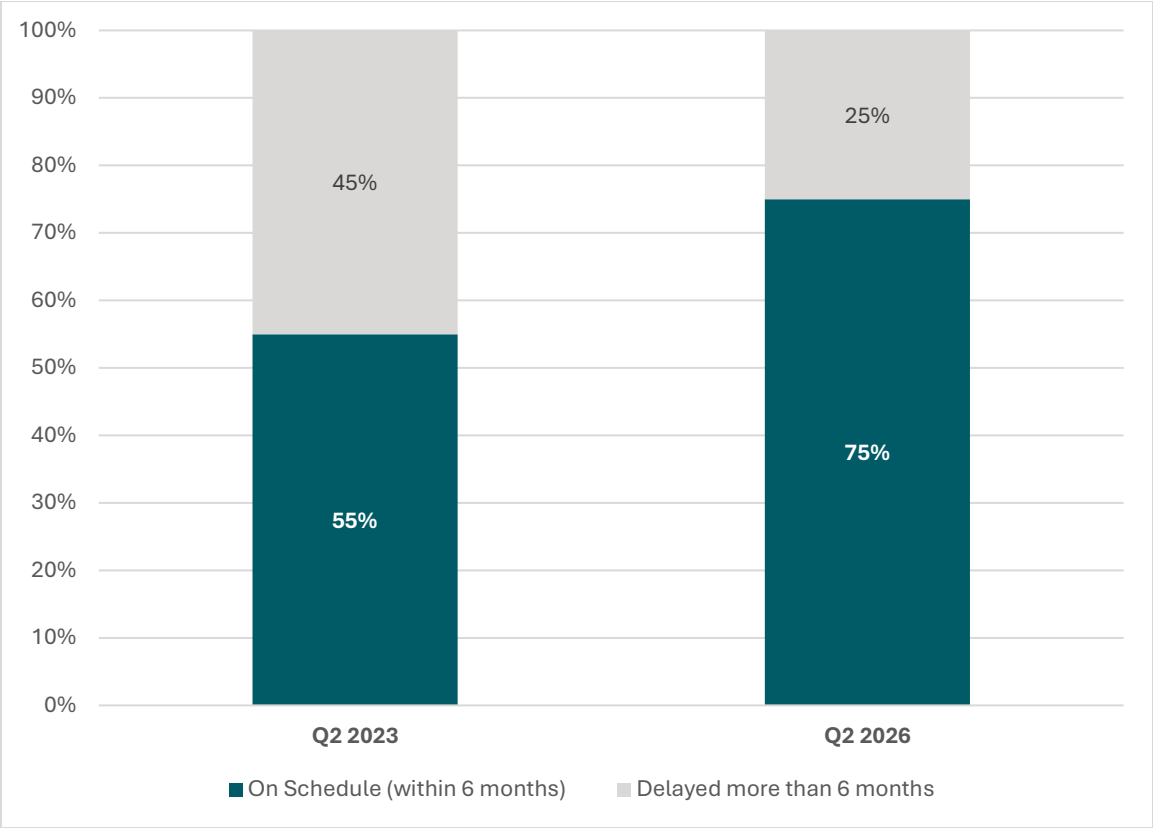

Figure 2: Schedule Performance of the Capital Projects Portfolio (Q2 2026 vs Q2 2023)

As of Q2 2026, 88% of transmission projects in the execution phase with budgets exceeding $10M were forecasted to be completed below the AACE Class 3 upper bound (+30%) relative to their original approved budgets, and 75% were forecast to be completed within six months of their original in-service dates. This represents improvements of 24% in cost performance and 20% in schedule performance relative to Q2 2023. The median performance has also improved significantly, with a median cost variance of +6% in Q2 2023 compared to a median cost variance of -6% in Q2 2026. Similarly, in terms of schedule performance, in Q2 2023 there was a median delay of 2 months, whereas in Q2 2026 the median delay was 0 months. Furthermore, portfolio size has grown significantly, with $7,257.0M of transmission capital projects in the execution phase as of Q2 2026 relative to $6,180.5M in Q2 2023, representing a 17% increase in gross portfolio size.

These results demonstrate Hydro One's enhanced execution capabilities and its ability to effectively manage a larger and more complex capital program.

The increasing maturity of Hydro One's transmission capital delivery process has been validated by independent expert benchmarking. As detailed in TSP Sections 2.3 and 2.11, Hydro One engaged E Source Inc. (E Source) to compare Hydro One's transmission capital delivery process with the equivalent processes of industry peers. E Source concluded that, relative to a peer group panel of 14 electricity utilities across North America, Hydro One is second quartile or better in 9 of the 10 performance domains that were examined. Furthermore, relative to the prior study conducted in the prior Transmission revenue requirement application (EB-2021-0110), Hydro One has improved its level of maturity in 9 of the 10 performance domains, with the lone exception being Scope Management where Hydro One was already deemed "Fully Integrated".

2.1 PROJECT-LEVEL PERFORMANCE ACCOMPLISHMENTS

The portfolio-level improvements described above are also reflected in the following project-level accomplishments:

- Successful execution of several Air Blast Circuit Breakers (ABCB) Replacement projects:
    - Cherrywood (Phase 1) 12 x 230kV ABCB project was completed on schedule in 2023 and 5% below the Plan forecast.
    - Cherrywood 500kV ABCB Replacement (Phase 3-1) was completed on schedule in 2025 and 4% below the Plan forecast.
    - Middleport ABCB was completed on schedule in 2025 and 7% below the Plan forecast.
    - Beck 1 SS ABCB Replacement was completed on schedule in 2026 and 27% below the Plan forecast.
- Barrie Area Transmission Upgrade was completed on schedule in 2023 and 5% below the Plan forecast. Hydro One successfully met customer commitments by completing the scope of upgrades at Barrie TS, Essa TS, and the new 230kV E28/E29 transmission line.

- M30A/M31A Conductor Upgrade was completed on schedule in 2023 and 12% below the Plan.
- Hydro One improved the reliability of power flow between Ontario and New York through the on-time completion of the St. Lawrence phase shifter project in 2023, which was 3% below the Plan.
- Merivale TS Refurbishment is forecast to be completed 4% below the Plan through a combination of design, contracting, procurement, construction sequencing, and execution optimization measures.
- HV UG Cable – Replace C5E/C7E (Power Downtown Toronto project) was completed several months ahead of schedule in 2026 and 7% below the Plan through accelerated project in-servicing.
- Essa TS: T3 & Component Replacement was completed 20% below the Plan and a year ahead of schedule, through strong risk management, effective contract management, construction efficiencies, and advanced in-servicing.

3.0 DETAILED INDIVIDUAL INVESTMENT VARIANCE SUMMARIES

Hydro One has prepared detailed individual investment variance summaries for material investments with significant variances relative to the Plan forecast, included as Attachments 2A-2R. The Plan included 120 material transmission capital investments that are currently in execution phase or that have been completed. Note that these investments were at varying stages of maturity at the time of the Plan, with some in early planning phases. At the time, the cost to complete these projects was projected to be $5.7B with 43 of them (36%) in the planning phase. The current forecast for the 120 projects has increased by $680M or 12% to a total of $6.3B. This is a significant and notable achievement given the fact that many of these projects had planning level figures underpinning their cost forecasts. Furthermore, the overall variance for the subset of 77 projects that were in execution is only 6%, which is well within the AACE Class 3 range of expected outcomes.

The 13 projects listed below account for 74% of the $680M variance discussed above. Detailed variance summary documents have been provided for each of these projects:

- Port Arthur TS #1: MV, PCT & Component Replacement (see Attachment 2A)
- Bridgman TS Load Station Transformer Replacement (see Attachment 2C)
- Richview Manby Transmission Reinforcement Line (see Attachment 2D)
- Otto Holden TS: T3/T4 & Component Replacement (see Attachment 2G)
- Bruce A TS: 500kV Switchyard Replacement (see Attachment 2H)
- Lakehead TS: Component Replacement (see Attachment 2I)
- Wawa TS: Component Replacement (see Attachment 2K)
- Rexdale TS: M/C Switchgear & Component Replacement (see Attachment 2L)
- Preston TS: T3, T4 & Component Replacement (see Attachment 2O)
- D6 Transmission Line Refurbishment (see Attachment 2N)
- Moose Lake TS: Component Replacement (see Attachment 2P)
- Essa TS: 500kV ABCB & Component Replacement (see Attachment 2R)
- Richview to Trafalgar 230kV Conductor Upgrade (see Attachment 2U)

For eight of the 13 projects above, the Plan forecasts reflected the early planning phase that these projects were in (for the reasons expressed below). All eight projects experienced a cost increase due to work definition maturity resulting in scope changes, and almost all were impacted by execution factors including cost escalation. Prior to the start of the execution phase, a detailed execution plan and an AACE Class 3 estimate were completed for all eight projects, and all are currently forecast within the AACE Class 3 range of expected outcomes, aligning with the expected project-level maturity. The other five projects experienced cost increases due to execution factors, mainly related to scope refinements (including project requirements, site conditions, etc.) and higher input costs relative to when the projects were initially planned. Collectively, across the 13 projects, Hydro One successfully reduced the combined cost by over $80M through effective risk management, construction efficiencies, schedule acceleration, and other steps undertaken.

In preparation for this Application, Hydro One has had to develop forecasts for large, complex and multi-year transmission projects over a seven-year period (2026 to 2032). Developing AACE Class 3 estimates can take months to years depending on the nature

of the project given the planning, development and design work required, and at a significant cost. Given the number of projects that must be planned and executed over the seven-year timeframe, it is not practical to complete execution-ready estimates at this stage nor would it be appropriate for projects in the latter years of the seven-year period.

Preparing AACE Class 3 estimates for every proposed investment would be cost prohibitive and be subject to risk of scope change, timing or priority over this seven-year period. Such an approach would not represent prudent stewardship of resources and would unnecessarily increase costs borne by Ontario customers, without providing commensurate value.

Thus, projects within a five-year rate period will naturally be at different stages of development and, therefore, have varying levels of estimate maturity. Early-stage projects are expected to have lower maturity of scope, schedule, and cost estimates than projects approaching execution, which is an appropriate and prudent aspect of capital planning. As projects advance through the stage-gated capital delivery process, estimates are progressively refined and accuracy improves.

Hydro One has a proven track record of delivering large capital projects through a mature capital delivery framework supported by strong governance, oversight, and execution capabilities. The company's Capital Project Delivery Model provides structure and rigour, including a stage-gated approach to advancing investments from initiation through execution and closure, ensuring appropriate review and oversight throughout the project lifecycle.

Using similar cost-saving methods, the six projects below are projected to be, or have been completed under the Plan project total, by over $10M each, or a total $108M below Plan estimates. Detailed variance summary documents have been provided for each of these projects:

- Middleport TS: ABCB Replacement (see Attachment 2B)
- Beck 1 SS: ABCB Replacement (see Attachment 2E)

- Gardiner TS: T1, T2, PCT & Component Replacement (see Attachment 2F)
- Merivale TS Refurbishment (see Attachment 2J)
- Lake TS: T2 & Component Replacement (see Attachment 2M)
- Essa TS: T3 & Component Replacement (see Attachment 2Q)

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Project Name	Port Arthur TS #1: MV, PCT & Component Replacement
Variance Categories	Work Definition Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Planning	T-SR-03	$24.3M	2026
Subsequent Class 3 Estimate			
		$47.6M ($38.1M - $61.9M)	2027
EB-2026-0164			
Execution	T-SR-03	$47.1M	2027
Variance to EB-2021-0110:		+94%	+1 Year
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Port Arthur TS #1: MV, PCT & Component Replacement was included in the Plan[1] with total net funding of $24.3M and a planned in-service year of 2026. At that time, the project was in the planning phase with a focus on upgrading and replacing assets that affected system operability and reliability at Port Arthur TS. This included replacing 27.6kV circuit breakers, medium voltage (MV) switches, alternating current and direct current station service equipment, instrument transformers, and protection and control equipment. The project scope later increased to expand the site, relocate the feeders, install a new protection, control and telecommunications (PCT) building, and replace additional MV switches as the execution strategy changed from in situ to greenfield to minimize customer disruptions.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

Currently, the investment is in execution and forecast to be completed at a cost of $47.1M, which is $22.8M (94%) above the Plan forecast but $0.5M below the Advancement of Cost Engineers (AACE) Class 3 estimate. The in-service date is one year later than the Plan schedule but in line with the AACE Class 3 schedule. These cost and schedule variances relative to the Plan forecast reflect the refined execution plan developed as the project matured and cost escalation caused by market conditions. These developments were captured in the AACE Class 3 estimate. To minimize the cost increase, Hydro One collaborated with the local distribution company (LDC) to reduce relocation costs for Hydro One by utilizing overhead feeder sections rather than underground cables. Additionally, major equipment was ordered prior to execution to minimize price increases.

This investment, with the expanded greenfield scope, will increase reliability in the Thunder Bay area by addressing equipment failure risk and lowering long-term operating and maintenance costs.

1.0 SYSTEM NEED

Port Arthur TS has provided electricity to the Thunder Bay area since 1950 with certain assets and infrastructure that have reached end of life. The expanded greenfield scope of this investment remains the preferred alternative as it addresses equipment failure risk, increases reliability, and lowers long-term operating and maintenance costs while minimizing disruption during construction. This investment will support future load growth and increased generation capacity.

2.0 PROJECT VARIANCE EXPLANATION (PORT ARTHUR TS #1)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing 27.6kV circuit breakers, MV switches, alternating current and direct current (DC) station service equipment, instrument transformers, and protection and control equipment. Subsequently, the project scope increased to expand the site, relocate the feeders, install a new PCT building, and replace additional MV switches.

Currently, the investment is in execution and approximately 30% complete, with an in-service date change of one year relative to the Plan schedule. This was driven by material delivery delays, which are further discussed in Section 4.2.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project has experienced a cost and schedule variance due to work definition maturity and execution factors, which are further explained below. The project is forecast to be completed below the AACE Class 3 estimate, which is also discussed below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $22.8M variance above the Plan forecast is attributed to work definition maturity along with material cost escalation. The project's execution strategy was refined to complete a greenfield replacement rather than an in situ replacement. The greenfield approach

minimizes customer disruptions during construction, addresses future capacity needs, and improves system reliability. The in situ alternative was considered, however, it was rejected due to poor equipment condition, along with substandard working clearances from live equipment, which meant the work was not feasible to construct safely without extensive outages. To execute a greenfield replacement, additional scope was required, including the replacement of additional MV switches, site expansion, feeder relocation, and the installation of a new PCT building. These factors, along with procurement and delivery delays, caused a schedule change as well.

When the project entered execution, an AACE Class 3 estimate was completed with a net value of $47.6M and an expected outcome range of $38.1M to $61.9M (-20% to +30%). The investment is forecast to be completed $0.5M below the AACE Class 3 estimate of $47.6M.

4.1 WORK DEFINITION

The project was in the planning phase when the Plan forecast was established. As the project matured, it was determined that a greenfield installation would be the necessary approach for this project due to the poor condition of the live equipment, creating unsafe working conditions and requiring extensive outages if done in situ. Changing the strategy led to the installation of additional switches, site expansion, feeder relocation, and a new PCT building, contributing approximately $20.0M to the variance. The greenfield approach minimizes customer disruption during construction while alleviating space constraints for future upgrades and increasing short-circuit capacity. This ensures the station can safely accommodate future load growth and system enhancements while lowering operating and maintenance costs. Constructing the greenfield yard also provides long-term value to customers who have experienced sustained and unplanned power outages over the last decade by improving the reliability and resilience of the electricity system serving them and supporting critical infrastructure such as Thunder Bay’s water treatment plant. The station’s existing equipment limited the ground fault level of the station and, in turn, limited generation capacity. The new greenfield approach will remove this restriction and allow for an increase in generation capacity.

4.2 EXECUTION FACTORS

To maintain customer reliability, Hydro One adjusted the outage strategy in response to a six-month delay in the delivery of circuit breakers by the manufacturer. Proceeding as originally planned would have resulted in outages during the winter period, leaving customers without power during the coldest months of the year, as these customers can only be supplied from Port Arthur TS. These outages were subsequently delayed to the following spring to minimize customer impact.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The project was in the planning phase when the Plan forecast was established, which was based on a high-level scope. With increased project maturity, the greenfield solution alternative was selected to provide long-term value to customers in the area. An AACE Class 3 estimate based on the greenfield approach was completed after approval of the project execution plan. Currently, the project is forecast to be completed below the AACE Class 3 estimate, as further discussed above in Section 4.0. This aligns with Hydro One's Capital Project Delivery Model in terms of project-level maturity.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance. Hydro One has a robust capital project delivery model in place with defined stage gate points to ensure that the most cost-effective and prudent solutions in the interest of customers are pursued. In this case, even though the scope has increased significantly, it was done to the ultimate benefit of customers. To minimize costs associated with the distribution feeder relocation, Hydro One collaborated closely with the LDC to develop a cost-effective solution. The LDC agreed to utilize overhead feeder sections instead of a more expensive underground cable solution, reducing the overall cost and avoiding additional expenditures. Additionally, equipment was ordered at the beginning of the planning phase to mitigate the risk of potential price escalation resulting from fluctuations in raw commodity prices in the global market.

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Project Name	Middleport TS: ABCB Replacement
Variance Categories	Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Execution	T-SR-02	$178.1M	2025
EB-2026-0164			
Complete	T-SR-02	$165.5M	2025
Variance to EB-2021-0110:		-7%	0 Years

Summary:

Middleport TS: ABCB Replacement was included in the Plan[1] with total net funding of $178.1M and a planned in-service year of 2025, with the project in execution. The primary scope of this investment was to replace the air-blast circuit breakers (ABCB) and oil circuit breakers (OCB) with sulfur hexafluoride (SF_6) breakers; replace other end of life assets, including breaker disconnect switches; remove free-standing current transformers; and upgrading the existing alternating current (AC) and direct current (DC) station services. Protection, control, and telecom equipment were upgraded as well.

The investment was successfully completed on schedule and $12.6M (7%) below the Plan estimate, due to effective risk management, construction efficiency, and scope optimization.

Middleport TS: ABCB Replacement improves reliability, reduces operating risks and maintenance costs, and ensures compliance with regulatory requirements.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

1.0 SYSTEM NEED

Middleport TS is a major station located southwest of Hamilton, providing bulk power to the Hamilton and Niagara areas. The existing breakers and associated facilities were at end of life and costly to maintain as parts were obsolete and no longer supported by the manufacturer. This investment was the preferred alternative as it reduced operating risks and maintenance costs, improved reliability, and ensured compliance with regulatory requirements.

2.0 PROJECT VARIANCE EXPLANATION (MIDDLEPORT TS: ABCB)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan estimate, the project scope included replacing ABCBs and OCBs with SF_6 breakers; replacing breaker disconnect switches; removing free-standing current transformers; upgrading the existing AC and DC station services; and upgrading the protection and control systems.

The investment was completed in 2025, on schedule relative to the Plan estimate.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan estimate, the project total cost was lower due to execution factors, which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $12.6M variance below budget was achieved by reducing the impact of execution factors through effective risk management, construction efficiency, and scope optimization, leading to reductions in interest, overhead, and labour costs.

4.1 EXECUTION FACTORS

The project involved a large volume of repeatable work completed across multiple outages, allowing efficiencies to be captured through standardized work practices and productivity improvements as crews progressed through execution. These conditions

enabled the project team to successfully reduce outage delay and cancellation risks, reducing contingency and overall cost. For example, pre-building and partial commissioning work ahead of future outages minimized any schedule impact. Outage efficiency and productivity gains led to lower construction costs as well. Furthermore, site conditions allowed the scope to be optimized by reducing removal costs. Approval was gained to retain the bypass and access roads which were originally thought to be temporary. The bypass and access roads will allow for future outage flexibility and improve operational efficiency by creating alternative routes in the event of future replacement work.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The estimate in the Plan reflected the project's stage of development at the time (being in the execution phase) and was developed based on a risk workshop consistent with Hydro One’s practices to identify and mitigate risks.

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Project Name	Bridgman TS Transformer Replacement
Variance Categories	Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Execution	T-SR-03	$69.3M	2024
EB-2026-0164			
Complete	T-SR-03	$90.8M	2026
Variance to EB-2021-0110:		+31%	+2 Years

Summary:

Bridgman TS Transformer Replacement was included in the Plan[1] with total net funding of $69.3M and a planned in-service year of 2024, with the project in execution. The primary scope of this investment was to replace four 75 MVA power transformers with 100 MVA units to accommodate load growth in the City of Toronto, including other ancillary assets and general station infrastructure upgrades and renewals such as support structures, fire walls, spill containment and drainage systems, and noise abatement walls.

The investment was substantially completed at a cost of $21.5M (31%) above the Plan and two years later, due to execution plan changes, design maturity, constructability challenges, and cost escalation.

Successful mitigation methods were implemented to prevent further delays, including the strategic use of overtime hours within the execution plan and weekly coordination meetings to prevent conflicts between multiple projects on-site. These efforts ensured the four transformers were replaced by 2024, achieving the key driver of the investment.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

Furthermore, through value engineering practices and risk-management oversight, Hydro One reduced the potential overall cost variance by approximately $8.0M. As a result, the variance relative to the Plan estimate is $21.5M.

This investment was necessary to maintain long-term reliability of supply to Toronto Hydro customers in the surrounding local area by addressing the poor condition of the power transformers and other end-of-life assets.

1.0 SYSTEM NEED

Bridgman TS consists of five power transformers that supply approximately 185 MVA of peak load to local area Toronto Hydro customers. This investment remained the preferred alternative as it addressed the poor condition of the power transformers, other end of life assets, spill containment, and noise abatement deficiencies. Not proceeding with this work would have compromised the long-term reliability of supply to Toronto Hydro customers in the surrounding local area.

2.0 PROJECT VARIANCE EXPLANATION (BRIDGMAN TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan estimate, the project scope involved the replacement of four power transformers, other ancillary assets, and the renewal and upgrade of general station infrastructure including support structures, fire walls, spill containment and drainage systems, and noise abatement walls.

The investment was substantially completed in 2026 with an in-service date change of two years relative to the Plan. This was driven by material delivery delays and outage constraints which are further discussed in Section 4.1.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan estimate, the project experienced a cost and schedule variance due to execution factors which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $21.5M variance is mainly attributed to execution factors which included changes in the contingency tie-cable design to meet Toronto Hydro’s requirements, design maturity, constructability challenges, and cost escalation for cable relocation work completed by Toronto Hydro compared to preliminary estimates. These factors, along with material delivery delays and outage management constraints, led to a schedule delay as well.

4.1 EXECUTION FACTORS

Contingency Tie Cable Design Change: Toronto Hydro planned to use tie cables to eliminate the risk of load loss during the transformer replacements as they do not have additional load transfer capability. Assumptions were made during early project definition to utilize existing cables and ducts within the station. During project execution, once Toronto Hydro completed preliminary design work, these assumptions proved incorrect and higher capacity cables were needed, significantly impacting the design for the contingency tie cables and contributing to the cost variance. Projects involving Toronto Hydro present unique considerations due to shared sites containing assets owned and operated by both organizations. As aging assets reach end of life, there has been an increase in the volume of complex replacement work that necessitates detailed and collaborative planning between the organizations. Historically, early collaboration between Hydro One and Toronto Hydro relied on preliminary assumptions that formed the basis of project estimates. As coordinated projects between the two entities have become increasingly complex in recent years, these assumptions can no longer be relied upon when estimating the early-stage cost and scope of such projects.

Additionally, constructability challenges impacted costs related to the contingency tie cable route due to underground site conditions. Numerous buried and abandoned assets were uncovered that were unknown during the planning phase, resulting in changes to work methods and additional costs for material, labour, construction methods, and soil disposal. Overall, the contingency tie cable design changes contributed approximately $6.0M to the variance.

Hydro One's planning process has evolved based on the experience from Bridgman TS to include more comprehensive early engagement with major customers such as Toronto Hydro and other LDCs, including Hydro One providing early funding for detailed design and estimates if required. In addition, engineering practices have been enhanced through targeted training and increased emphasis on the use of exploratory studies and record drawings to support the effective incorporation of existing site conditions into project designs.

Constructability: The outage staging plan had to be revised due to constructability requirements that became known during execution based on final design drawings. The revised plan required an increased level of coordination with external contractors, resulting in over 100 additional Work Protection Permit changes. Outage windows to perform work were also shortened due to delays on other critical path activities, resulting in significant premium costs, overtime costs, and additional construction staging. The cost impact on the project from outage-related changes was approximately $4.0M. Outage risks were previously identified and partially reduced through upfront coordination and continual communication with Toronto Hydro, and Operating and Outage Planning on a regular basis.

Furthermore, due to the congested and limited storage space at Bridgman TS, project materials and equipment were stored across the street at a Hydro One junction site, adding approximately $2.0M to the project cost. Although a known risk, the daily material handling effort through heavy traffic and congested streets was higher than estimated. Hydro One tried to mitigate this risk through proactive engagement with the community and city. With this, the small footprint of the project area required Toronto Hydro to work under Hydro One's Notice of Project, resulting in additional contract monitoring efforts and site coordination that were not planned.

Cable Relocation Work: Toronto Hydro completed cable relocations throughout and around the site to support the transformer replacement work, which was initially estimated before their site investigation and preliminary engineering was completed. The change of the contingency cable tie plan as well as site conditions including traffic congestion, high ground water level, and unexpected underground obstructions led to changes in the design and construction methods, resulting in approximately $4.0M of increased costs for labour, material, and engineering support.

Beyond the reasons noted above, changes in estimating assumptions, procurement issues, heritage building work, along with increased contingency, overhead and interest also contributed to the variance.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

Multiple unforeseen challenges occurred during the execution of this project, causing a cost and schedule variance. While reasonable assumptions were made during the project definition phase, they were later invalidated when Toronto Hydro completed its designs and estimates and when Hydro One's construction started. This led to revisions of the execution plan, requiring additional resources and time. Hydro One has since enhanced the process to include early engagement and funding for detailed designs and estimates. In addition, due to the urban location of the site, there was limited yard space, requiring off-site work and storage. Additional external factors such as traffic congestion were accounted for, however, unexpected circumstances caused the impact to be greater.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

To maintain project schedule and power-outage commitments and minimize delays from unforeseen conditions at the site, overtime hours were incorporated into the execution work plan, which ensured all four transformer units were replaced before 2026. Furthermore, weekly coordination and management oversight meetings were put in place to prevent conflicts between multiple projects within the site. In addition to conflict mitigation, significant project savings were realized through value engineering practices and risk-management oversight, where Hydro One effectively reduced the overall project cost by approximately $8.0M. Without these actions, the variance would have been approximately $30.0M; with them, the variance was lowered to approximately $21.5M.

Project Name	Richview Manby Transmission Reinforcement - Line
OEB File No.	EB-2023-0199
Variance Categories	Work Definition Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Planning	T-SS-06	$32.6M	2026
Subsequent Class 3 Estimate			
		$71.3M ($57.0M - $92.7M)	2026
EB-2026-0164			
Complete	T-SS-06	$59.8M	2026
Variance to EB-2021-0110:		+83%	0 Years
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Richview Manby Transmission Reinforcement – Line was included in the Plan[1] with total net funding of $32.6M and a planned in-service year of 2026, with the project in the planning phase. The primary scope of this investment was to rebuild the existing idle 115 kV transmission line as a new 230 kV 6.5km-long double circuit line, connecting Richview TS and Manby TS. The project scope later increased slightly to include upgrading the overhead portion of the circuit at Applewood Junction.

The investment was substantially completed on schedule and $27.2M (83%) above the Plan forecast but $11.5M below the Advancement of Cost Engineers (AACE) Class 3

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

estimate. The AACE Class 3 estimate reflected refinement of execution methods to minimize disruption to community green space and to support local communities. These developments were captured in the OEB-approved Section 92 Leave to Construct (S92 LTC) application (EB-2023-0199).

Richview Manby Transmission Reinforcement – Line was substantially completed below the approved amount in the S92 LTC and the AACE Class 3 estimate. This was achieved through effective risk management strategies that led to efficient project execution, early engagement to avoid delays, and design optimization while achieving commitments to the community. Along with advanced partial in-servicing, Hydro One reduced the total cost and variance by approximately $12.0M. As a result, the variance was approximately $27.0M relative to the Plan forecast; without these actions, the variance would have been approximately $39.0M.

This investment helps address the rapidly growing electricity demand in Toronto and enhances transfer capability to support continued load growth across the Greater Toronto Area (GTA), as recommended by the Independent Electricity System Operator (IESO).

1.0 SYSTEM NEED

Richview Manby Transmission Reinforcement – Line was recommended in the 2020 Toronto Regional Infrastructure Plan led by Hydro One and the 2019 Toronto Integrated Regional Resource Plan led by the IESO to help meet the rapidly growing electricity demands in west and central Toronto. This investment remained the preferred alternative as it addressed the transfer capability needed to support continuous load growth in the GTA, therefore supporting economic growth as well.

2.0 PROJECT VARIANCE EXPLANATION (RICHVIEW MANBY)

2.1 REGULATORY CONTEXT

Richview Manby Transmission Reinforcement – Line received OEB S92 LTC approval in 2023. In the approval, the project was planned to be in service in March 2026 with a gross total cost of $73.1M, which is higher than the actual project cost. This amount reflected the expected project costs and associated contingencies at the time of application, supporting the scope required to address the IESO's load growth forecast. Deliberate cost-saving actions were taken as discussed in Section 6.0 to manage the project cost with the investment being substantially completed at the lower end of the AACE Class 3 estimate range.

2.2 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the proposed project involved reinforcing the transmission system on the South-West Greater Toronto Area transmission corridor. Specifically, the project involved rebuilding the existing 6.5 km idle 115 kV double-circuit line as a 230 kV double-circuit line, connecting the new 230 kV conductors in parallel with the existing circuits, and modifying the protection and control settings at Richview TS and Manby TS to incorporate the new line. Subsequently, the project scope increased slightly to include upgrading the overhead portion of the circuit at Applewood Junction.

The investment was substantially completed in 2026, on schedule relative to the Plan.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project experienced a cost variance primarily due to work definition maturity, which is further explained below. The project was substantially completed below the AACE Class 3 estimate, which is also discussed below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The AACE Class 3 estimate was completed with a net value of $71.3M and an expected outcome range of $57.0M to $92.7M (-20% to +30%). The investment has been substantially completed $11.5M below the AACE Class 3 estimate of $71.3M but $27.2M above the Plan forecast. The project's scope was supported by the IESO as it is the most cost-effective solution to address the growing electricity demands in west and central Toronto.

4.1 WORK DEFINITION

The cost increase was due to the refined construction execution methods required to minimize disruption of vegetation and valuable community green space along the corridor. The refinements were largely triggered by the Class Environmental Assessment (EA) for Minor Transmission Facilities that was completed on June 5, 2023. The main concerns heard from the public and other stakeholders through the Class EA process and project execution plan development included vegetation preservation, minimization of loss of privacy, site drainage, and minimization of construction disturbance. Mitigation measures to minimize project impacts increased costs by approximately $10.0M and included, planning access roads away from vegetation and backyards, consideration for tall towers to clear trees and objects, and implementation of complex stringing methods.

Furthermore, offsetting measures for the residual project impacts have been incorporated in the execution plan totalling approximately $6.0M, which include a commitment to collaborate with stakeholders on public amenities, a restoration plan, and giveback opportunities. The amenities being constructed as part of this project are referred to as the Etobicoke Greenway, which has the support of the City of Toronto and local communities. The measures and actions taken to address community concerns, as noted

through the Class EA consultation, are deemed essential to project execution and to obtaining stakeholder support and environmental approvals as further described in the approved S92 LTC. Additionally, higher fault currents have necessitated additional grounding and bonding work to reduce the hazards of step and touch potentials.

4.2 EXECUTION FACTORS

The project was paused from early 2020 up until 2021, requiring further review by the IESO. Once resumed, material costs increased by approximately $7.0M due to the volatility of the global commodities market and inflation. The remainder of the variance is attributed to changes associated with specific tower foundations, construction execution methodologies, access and staging plans.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The project was in a planning phase when the Plan forecast was established, which was based on a high-level scope. The Class EA process had not yet been undertaken and, as such, the required environmental mitigation measures and commitments for this project were not yet known. Additionally, as the project matured, a minor scope change to incorporate the upgrading of an overhead portion of the circuit at Applewood Junction was added to comply with the IESO System Impact Assessment. The AACE Class 3 estimate incorporating the results of the Class EA and minor scope change was prepared and the project was substantially completed below its net value of $71.3M as discussed above in Section 4.0. This aligns with Hydro One's Capital Project Delivery Model in terms of project-level maturity.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance relative to the Plan forecast. To meet the IESO need date, regulatory approvals were submitted on schedule, and regular status meetings were arranged to proactively provide and monitor approvals. Similarly, early engagement with major material vendors ensured purchase orders and prices were finalized promptly, reducing the risk of increased procurement costs and

delivery delays due to the volatility of the global supply chain markets. In addition, several mitigation actions contributed to reducing the total cost by approximately $12.0M. Without these actions, the variance would have been approximately $39.0M; with them, the variance was lowered to approximately $27.0M. These actions included: proactive management of community-related risks to maintain project schedule; early engagement and management escalations to avoid permit delays, thereby limiting the use of project contingency funds; and revised design of recreational amenities as part of the Etobicoke Greenway. Additionally, advanced partial in-servicing also contributed to the cost reduction.

Project Name	Beck 1 SS: ABCB Replacement
Variance Categories	Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Execution	T-SR-02	$54.2M	2026
EB-2026-0164			
Complete	T-SR-02	$39.7M	2026
Variance to EB-2021-0110:		-27%	-

Summary:

Beck 1 SS: ABCB Replacement was included in the Plan[1], with total net investment of $54.2M and a planned in-service year of 2026, with the project in execution. The primary scope of this investment was to replace the two 115 kV air-blast circuit breakers (ABCBs), associated switches, and other poor condition equipment. The protection and control system was upgraded as well.

The investment was substantially completed on schedule and $14.5M (27%) below the Plan estimate, due to effective project execution, enhanced stakeholder coordination, and construction optimization initiatives.

Beck 1 SS: ABCB Replacement improves reliability and station operation, accommodates the increase in total power export, eliminates ongoing maintenance costs, and ensures continued compliance.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

1.0 SYSTEM NEED

Beck 1 SS connects 450 MW of hydroelectric generation from OPG to the 115 kV network in the Hamilton/Niagara Region. The existing assets were in deteriorated condition, obsolete, and at end of life, requiring replacement to maintain system reliability. This investment was the preferred alternative as it reduced operating risks, improved reliability and station operation, accommodated the increase in total power export, eliminated ongoing maintenance costs, and ensured continued compliance.

2.0 PROJECT VARIANCE EXPLANATION (BECK 1 SS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan estimate, the project scope involved replacing two 115 kV ABCBs and multiple associated switches. Other poor condition equipment and protection and control system upgrades were included as well.

The investment was substantially completed in 2026, on schedule relative to the Plan estimate.

3.0 UPDATED COST FORECAST AND VARIANCE

Relative to the Plan estimate, the project total cost was lower due to execution factors, which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $14.5M variance below budget was achieved by reducing the impact of execution factors through effective project execution, enhanced stakeholder coordination, and construction optimization initiatives.

4.1 EXECUTION FACTORS

The project’s operating environment, collaboration with Ontario Power Generation (OPG), station configuration, and construction sequencing enabled optimization opportunities throughout execution. The project team effectively mitigated schedule risks and improved

labour productivity through enhanced coordination with OPG, including weekly execution planning meetings and regular outage coordination sessions. These efforts led to optimized outage schedules, reduced overlapping activities, and shared use of resources. Additional savings were achieved through protection and control optimization initiatives that lowered labour and commissioning efforts while maintaining system reliability requirements. This was achieved through detailed engineering reviews, temporary setting requirements, and a reduction in related implementation activities.

As construction progressed, the project team identified and implemented several operational and execution improvements that were not fully known during estimate development. These included partial in-servicing of completed bays, maximizing transmission capability during construction, expanding available work fronts, increasing material staging areas, improving site logistics, and developing more efficient approaches for transmission line conductor replacement in difficult-to-access locations. Collectively, these measures generated project cost savings through improved productivity and reduced outage dependence. Additional savings were realized through optimization of removal scopes, recovery of scrap materials, improved waste management practices, and reassessment of legacy cable removal requirements that had accumulated over several decades. While a significant portion of savings resulted from execution and coordination initiatives, savings were also attributable to labour productivity outperforming the assumptions used in the original forecast.

This investment highlights the benefits of proactive outage coordination, early stakeholder engagement, optimized construction sequencing, and continuous improvement throughout execution. These practices can be leveraged on future similar complex station refurbishment projects to enhance schedule performance, manage costs, and further improve project outcomes.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The original estimate appropriately reflected the complexity and uncertainty associated with refurbishment work in an operating station environment. It incorporated assumptions informed by the first two completed bays, known access constraints, and outage requirements. Based on the information available at the time the Plan estimate was developed, these assumptions were considered reasonable and provided an appropriate basis for the original forecast.

Project Name	Gardiner TS: T1, T2, PCT & Component Replacement
Variance Categories	Emergent Needs Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Planning	T-SR-03	$61.9M	2025
Subsequent Class 3 Estimate			
		$48.9M ($39.1M - $63.6M)	2027
EB-2026-0164			
Execution	T-SR-03	$39.2M	2026
Variance to EB-2021-0110:		-37%	+1 year
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Gardiner TS: T1, T2, PCT & Component Replacement was included in the Plan[1] with total net funding of $61.9M and a planned in-service year of 2025, with the project in the planning phase. The primary scope of this investment is to replace the existing deteriorated transformers and associated equipment. New spill containments will be installed to meet the latest standards and regulations, in addition to replacing alternating current station service and associated protection, control, and telecom (PCT) equipment. The project was subsequently divided into two phases to prioritize the replacement of the transformers due to their deteriorating condition and performance concerns. This approach addressed the highest risk assets first, improving reliability and reducing potential outage implications, thereby delivering the greatest value to customers.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

Currently, the investment is in execution and is forecast to be completed $22.7M (-37%) below the Plan forecast and a year later, but $9.7M below the Association for the Advancement of Cost Engineers (AACE) Class 3 estimate. The AACE Class 3 estimate reflects scope reductions to prioritize the transformers and the development of a detailed execution plan as the project matured. Gardiner TS: T1, T2, PCT & Component Replacement will improve reliability for the customers in the Kingston area and minimize operational risks.

1.0 SYSTEM NEED

Gardiner TS is mainly a load-serving station, located in Kingston, with two switchyards: one supplying Kingston Hydro and the other supplying Hydro One distribution loads, and with a 230 kV connection to Wolfe Island wind farm generation (197.8 MW). The existing assets are in poor condition and need to be replaced on a priority basis to improve reliability for the customers in the area and minimize operational risks, making this investment the preferred alternative.

2.0 PROJECT VARIANCE EXPLANATION (GARDINER TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing 230/44 kV, 75/100/125 MVA step-down transformers, transformer spill containment, alternating current station service, and associated PCT equipment. Subsequently, the project was divided into two phases to prioritize the replacement of the transformers. Replacement of the PCT equipment and medium-voltage switchgear will be done under a separate future investment.

Currently, this investment is in execution and is approximately 81% complete, with an in-service date change of one year relative to the Plan forecast. This was driven by the development of a detailed execution plan, which is further discussed in Section 4.2.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project total cost is lower however due to emergent needs and execution factors, the schedule has been delayed by one year, which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $22.7M variance below the Plan forecast is due to emergent needs, resulting in scope changes as the transformers required priority replacement due to their deteriorating condition and increasing performance concerns. The impact from execution factors was

eliminated through construction optimization and risk management, further reducing the project cost.

An AACE Class 3 estimate based on the updated scope was completed with a net value of $48.9M and expected outcome range of $39.1M to $63.6M (-20% to +30%). The investment is forecast to be completed $9.7M below the AACE Class 3 estimate of $48.9M.

4.1 EMERGENT NEEDS

In 2024, prior to the execution of the project, Hydro One identified that the tap changer on the first transformer was defective and all efforts to fix it were unsuccessful. In addition, the second transformer developed an oil leak, making the station unreliable and vulnerable to unplanned outages, affecting customers with limited alternative supply options. Due to this risk and potential failure, the project needed to proceed in an accelerated manner to replace the transformers and ensure reliable power supply to the City of Kingston. It was determined that the transformers would be replaced prior to the PCT equipment and medium-voltage switchyard, which will be done under a separate future investment.

4.2 EXECUTION FACTORS

Through proactive risk mitigation and construction optimization, the project team realized approximately $7.0M in savings. These savings were achieved through several targeted initiatives based on the available opportunities for this project, including the advance procurement of materials to mitigate price escalation risks, the utilization of spare 46 kV cables from other projects, construction work plan optimization, crew size optimization, and reduction in rental equipment durations during various construction phases. In addition, savings were also achieved through successful execution of planned outage cutovers on 230 kV transmission lines supplying the station. This resulted from project planning activities, execution schedule development, and schedule adherence, which avoided delays and associated costs.

While the transformer replacement scope was prioritized, the in-service date was adjusted based on detailed development of the execution plan and extended transformer

procurement timelines. The required transformers had a lead time of approximately 36 months, compared to the typical 12 to 24 months experienced in previous years. To mitigate further schedule impacts, the project team proactively procured the transformers based on anticipated demand. The use of this initiative reduced further delays and supported the earliest feasible in-service date.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The project was in the planning phase when the Plan forecast was established, which was based on a high-level scope. Right before the project went into execution, it was discovered that maintenance on the transformer was no longer effective, increasing the urgency and changing the priorities. An AACE Class 3 estimate based on the updated scope was completed, with the project currently forecast below the estimated value, as further discussed above in Section 4.0. This aligns with Hydro One's Capital Project Delivery Model in terms of project-level maturity.

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Project Name	Otto Holden TS: T3/T4 & Component Replacement
Variance Categories	Work Definition

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Planning	T-SR-01	$68.7M	2027
Subsequent Class 3 Estimate			
		$109.6M ($87.7M - $142.5M)	2028
EB-2026-0164			
Execution	T-SR-01	$100.6M	2028
Variance to EB-2021-0110:		+46%	+1 Year
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Otto Holden TS: T3/T4 & Component Replacement was included in the Plan[1] with total net funding of $68.7M and a planned in-service year of 2027, with the project in the planning phase. The primary scope of this investment is to replace end of life assets including autotransformers, breakers, associated disconnect switches, station service, direct current (DC) station service and transfer scheme, and protection, control, and telecom (PCT) relays. The project scope subsequently increased to include a newly designed station at Antoine TS and a 0.6 km 230 kV transmission line.

Currently, the investment is in execution and forecasted to be completed $31.9M (46%) above the Plan forecast and a year later, but $9.0M below the Association for the Advancement of Cost Engineers (AACE) Class 3 estimate. The AACE Class 3 estimate

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

reflects scope refinement as the project matured, as well as changes made in response to outage requirements to ensure that the work is completed safely. This cost performance was achieved through securing long lead material to reduce exposure to input cost escalations, and continuous and effective coordination with stakeholders to optimize construction and outage strategies, eliminating the need for winter work which lowered the project cost.

Otto Holden TS: T3/T4 & Component Replacement will ensure reliability by addressing equipment failure and operational risks. This work supports the long-term reliability of the bulk electric system in the area and protects local customers from interruptions.

1.0 SYSTEM NEED

Otto Holden TS connects over 200 MW of hydroelectric generation from OPG's generating station to a multitude of transmission stations and is an interconnection with Hydro Québec. This investment remains the preferred alternative as it addresses equipment failure and operational risk due to end-of-life assets, ensuring reliability through upgraded infrastructure. Not proceeding with this work would have compromised the long-term reliability of the bulk electric system in the area and exposed local customers to interruptions.

2.0 PROJECT VARIANCE EXPLANATION (OTTO HOLDEN TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing 230 kV/115 kV autotransformers, 115 kV breakers, associated disconnect switches, station service, DC station service and transfer scheme, and PCT relays. Subsequently, the project scope increased to include a newly designed station at Antoine TS and a 0.6 km 230 kV transmission line.

Currently, the investment is in execution and approximately 79% complete with an in-service date change of one year relative to the Plan forecast. This was driven by outage requirements causing scope changes which are further discussed in Section 4.1.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project experienced a cost and schedule variance due to work definition which is further explained below. The project is forecasted to be completed below the AACE Class 3 estimate of $109.6M, which is also discussed below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $31.9M variance above the Plan forecast is attributed to work definition maturity as additional infrastructure was added and scope changes were required to account for complex and high-risk outage requirements, Ontario Power Generation's (OPG) safe site

access requirements and impacts to the interconnection with Quebec. Safety concerns and the limited space for expansion contributed to these changes as well.

An AACE Class 3 estimate was completed with a net value of $109.6M and expected outcome range of $87.7M to $142.5M (-20% to +30%). The investment is forecasted to be completed $9.0M below the AACE Class 3 estimate of $109.6M.

4.1 WORK DEFINITION

The Plan forecast was developed while the project was in the planning phase and assumed replacement of the existing equipment largely within the existing Otto Holden TS footprint. As the project progressed through detailed engineering, outage planning, constructability reviews, and stakeholder engagement, Hydro One identified several constraints that significantly increased execution complexity. Hydro One evaluated an in-situ replacement alternative; however, it was ultimately rejected due to limited station space, inadequate electrical clearances, and prolonged outage requirements affecting generation and customer supply. In addition, there were OPG access road constraints and existing site safety concerns.

Otto Holden TS is located adjacent to the Otto Holden Generating Station and is situated on constrained terrain near a rock embankment with limited room for expansion, equipment staging, and safe construction access. Detailed engineering and constructability reviews determined that replacing the autotransformers and associated equipment within the existing station footprint would create unacceptable safety, outage, and execution risks. A greenfield replacement was therefore identified as the only viable solution that maintained reliability and provided a safe means of executing the work. As a result, a revised solution was developed consisting of a new greenfield station, Antoine TS, and a new 0.6 km 230 kV transmission line connecting Antoine TS to Otto Holden TS. The revised scope also included additional associated PCT upgrades, station service replacement, line modifications, and decommissioning activities. These scope additions, along with overall design maturity, account for approximately $21.0M of the cost increase.

Hydro Québec requested the installation of a second autotransformer to maintain reliability for customers supplied by Otto Holden TS. Hydro One entered a facilities contribution arrangement with Hydro Québec under which Hydro Québec funds the incremental costs associated with the second autotransformer and related equipment, protecting Ontario ratepayers from these additional costs.

The remaining increase was attributable to contractor pricing obtained through competitive procurement, input cost escalation, and updates to contingency, interest, and overhead based on a more mature execution plan.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The project was in the planning phase when the Plan forecast was established, which was based on a high-level scope. The planning phase was undertaken at a level appropriate to support prudent decision-making while avoiding unnecessary costs and schedule impacts associated with extensive early-stage investigations. While this supported a reasonable assessment of scope, cost, and risk, certain site-specific conditions and execution constraints only became apparent as advanced engineering and work preparation activities progressed. Detailed engineering, outage planning, constructability reviews, geotechnical investigations, contractor engagement, and stakeholder consultations had not yet been completed.

As the project matured, Hydro One identified several constraints that were not fully understood during the planning phase, including limited electrical clearances within the existing station, space limitations, safety concerns related to the existing site configuration, OPG access requirements, and outage constraints that could not be accommodated while maintaining acceptable reliability for both Ontario and Hydro Québec customers. These findings demonstrated that replacement within the existing Otto Holden TS footprint was not a practical or prudent execution strategy. Consequently, construction of a new station (Antoine TS) and the associated transmission line emerged as the only viable solution

capable of maintaining system reliability, supporting safe construction, and addressing the operational risks associated with the existing station.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance. Hydro One has a robust capital project delivery model in place with defined stage gate points to ensure that the most cost-effective and prudent solutions in the interest of customers are pursued. In this case, even though the scope has increased, it was done to improve reliability and safety. Savings opportunities arose for this project from specific stakeholder arrangements and the timing of execution. Early approval for long-lead materials was obtained and production slots with the manufacturer were reserved, reducing the exposure to supply chain delays and cost escalations. In addition, continuous communication with contractors, OPG, Hydro Québec, and outage planners enabled optimization of the construction sequence and outage strategy. This coordination was critical because power outages at Otto Holden TS are difficult to schedule given its importance as a critical customer and generation connection point. In addition, through effective coordination of work with the contractor and refined execution planning, Hydro One eliminated the need for winter construction activities. Overall, these actions reduced the overall project cost by approximately $9.0M.

Project Name	Bruce A TS: 500kV Switchyard Replacement
Variance Categories	Execution Factors Work Definition

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Planning	T-SR-02	$316.2M	2027
Subsequent Class 3 Estimate			
		$516.5M ($439.0M to $594.0M)	2027
EB-2026-0164			
Execution	T-SR-02	$487.3M	2027
Variance to EB-2021-0110:		+54%	-
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Bruce A TS: 500kV Switchyard Replacement was included in the Plan[1] with total net funding of $316.2M and a planned in-service year of 2027, with the project in planning phase. The primary scope of this investment is to replace the existing end-of-life 500 kV air blast circuit breakers (ABCBs) and a 500 kV sulfur hexafluoride (SF6) breaker with new integrated 500kV gas insulated switchgear (GIS) within the current station property. In addition, three poor condition and end-of-life autotransformers will be replaced along with associated ancillary equipment, and protection, control, and telecom facilities. However, as the project matured, additional infrastructure was added due to the complexity of the site.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

Currently, the investment is in execution and forecasted to be completed $171.1M (54%) above the Plan forecast and on schedule, but $29.2M below the Association for the Advancement of Cost Engineers (AACE) Class 3 estimate. The AACE Class 3 estimate reflects scope refinement as the project matured and market cost escalation. To lower the risk of further price increases, manufacturers were engaged early to finalize technical specifications of the GIS building, and long lead materials were ordered to mitigate the risk of delivery delays. In addition, the project schedule was accelerated, lowering carrying costs, which reduced the overall project cost relative to the AACE Class 3 estimate

This investment will increase reliability by reducing the risk of equipment failure and maintenance costs while improving the flexibility and resilience of the station. Bruce A TS supports generation for a major baseload power provider that provides a significant portion of the province's electrical supply.

1.0 SYSTEM NEED

The Bruce A TS 500 kV switchyard is a major Bulk Power Station connecting the Bruce A Nuclear Generating Station to the 500 kV transmission network of the Bulk Electricity System as designated by the Northeast Power Coordinating Council. This investment was required to address the poor condition of the assets within the Bruce A TS 500 kV switchyard as confirmed through inspection, testing, and analysis. Leaving the assets in service would have resulted in further equipment deterioration and jeopardized the generating ability of a major baseload power provider, putting a significant portion of the province's electrical supply at risk. This investment remains the preferred alternative as it addresses the poor condition of the assets and maintains reliability, reducing the risk of equipment failure and maintenance costs.

2.0 PROJECT VARIANCE EXPLANATION (BRUCE A TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing 500 kV ABCBs, an SF6 breaker, autotransformers and associated switches, and upgrading the protection and control system. Subsequently, the project scope increased as the project matured.

Currently, the investment is in execution and approximately 89% complete with no in-service date change relative to the Plan forecast.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project experienced a cost variance due to execution factors and work definition maturity, which are further explained below. The project is forecast to be completed well below the AACE Class 3 estimate of $516.5M, which is also discussed below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $171.1M variance above the Plan forecast is mainly attributed to two categories – execution factors and work definition. The original forecast for the GIS was developed

based on an early investment at the Bruce Nuclear Complex, using pre-pandemic prices (from 2019). The specialized nature of the required GIS resulted in it being more susceptible to the impacts of post-pandemic global market disruptions. In terms of work definition, design maturity led to the need for additional infrastructure.

An AACE Class 3 estimate was completed with a net value of $516.5M and expected outcome range of $439.0M to $594.0M (-15% to +15%). The investment is forecast to be completed $29.2M below the AACE Class 3 estimate of $516.5M. The project scope associated with this estimate was supported by the Independent Electricity System Operator, because alternatives (i.e., in-situ replacement and greenfield switchyard) were rejected due to their implications for the reliability of supply to the province and nuclear safety. Additionally, the greenfield switchyard alternative would not result in cost savings as it was more complex and required a longer execution period.

4.1 EXECUTION FACTORS

Market conditions had a significant impact on the project due to the requirement for a specialized GIS solution, which was selected to address site-specific space constraints within the Bruce complex. An Air-Insulated Switchgear (AIS) solution was initially considered as it was a lower-cost option; however, an AIS design was not feasible due to limited space at the site. As a result, a GIS solution was determined to be the only viable option to safely address reliability concerns at a critical station that delivers power to a large portion of the province (the Plan forecast assumed a GIS solution). Given the specialized nature of GIS, its supply is limited, making it susceptible to disruptions in the global markets. Consequently, it has experienced major cost escalations. In addition, commodity costs for key inputs such as copper, steel, and aluminium increased significantly, contributing to higher warranty, security, shipping, and contingency costs. The original Plan forecast relied on pricing information from another project at the Bruce Nuclear Complex; however, as procurement advanced, actual market pricing and cost escalations for the specialized GIS solution were much higher than anticipated, increasing the overall project cost by approximately $120M.

4.2 WORK DEFINITION

Furthermore, as the project matured, to meet system requirements, equipment quantities for bus-work, capacitive voltage transformers, switches, grounding, AC/DC station service, cable system, and removals increased due to dense space at the site and eight road crossings, impacting the project complexity. Design maturity with additional infrastructure increased the overall project cost by approximately $50M.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The project was in a planning phase when the Plan forecast was established, which was based on historical data from completed projects. Significant cost escalation was experienced on the specialized GIS equipment, which could not have been predicted. As the project matured, additional equipment was added to the scope to improve reliability, operational flexibility, and maintainability of the new switchyard.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance. Hydro One has a robust capital project delivery model in place with defined stage gate points to ensure that the most cost-effective and prudent solutions in the interest of customers are pursued. In this case, even though the scope has increased, it was done to address reliability concerns at a critical station to provide for the operation of the system to deliver energy using different paths and allow operating flexibility. To accommodate potential impacts from global supply management constraints and unforeseen design challenges, Early Contractor Involvement with the GIS manufacturer and the constructor of the new GIS/relay building was initiated. This allowed for value engineering and early finalization of technical specifications. Furthermore, the project obtained early approval to order long-lead materials, which lowered the risk of delivery delays. Hydro One has recently optimized this project by accelerating the project schedule, which lowered contingency and commissioning costs, effectively reducing the overall project cost by approximately $30M.

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Project Name	Lakehead TS: Component Replacement
Variance Categories	Execution Factors Work Definition

Variance Summary

Project Phase	**ISD Reference**	**Project Total ($M)**	**In-Service Year**
EB-2021-0110			
Planning	T-SR-01	$38.8M	2028
Subsequent Class 3 Estimate			
		$73.1M ($58.5M - $95.0M)	2029
EB-2026-0164			
Execution	T-SR-01	$70.6M	2028
Variance to EB-2021-0110:		+82%	-
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Lakehead TS: Component Replacement was included in the Plan[1] with total net funding of $38.8M and a planned in-service year of 2028, with the project in the planning phase. The primary scope of this investment is to replace the existing oil circuit breakers, disconnect switches, low voltage circuit breakers, protection and control, station service, and other ancillary facilities that are at the end of life. The project scope later increased to install a new 115 kV relay building and replace additional switches and insulators.

Currently, the investment is in execution and is forecast to be completed $31.8M (82%) above the Plan forecast and on schedule, but $2.5M below the Association for the Advancement of Cost Engineers (AACE) Class 3 estimate. The AACE Class 3 estimate reflects evolving work methods to address feasibility concerns and scope refinement as

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

the project matured. Construction efficiencies reduced the project cost and variance by approximately $3.0M. Schedule delays were mitigated through regular and ongoing communication with Ontario Power Generation (OPG) and the Independent Electricity System Operator (IESO).

This investment will enhance system reliability in Northern Ontario by addressing end of life assets.

1.0 SYSTEM NEED

Lakehead TS was placed in service in 1955 and is a major hub connecting Northwestern Ontario to the rest of the transmission system. A large number of the existing assets were in a more deteriorated condition or obsolete than initially identified. This investment is the preferred alternative as it enhances system reliability and replaces end-of-life equipment that is critical to the Northern Ontario area.

2.0 PROJECT VARIANCE EXPLANATION (LAKEHEAD TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing 230 kV circuit breakers, 115 kV oil circuit breakers, associated disconnect switches, the protection and control system, along with other required equipment. Subsequently, the project scope increased to include a new 115 kV relay building and the replacement of additional switches and insulators.

Currently, the investment is in execution and approximately 10% complete, with no change to the in-service date relative to the Plan forecast.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, this project experienced a cost variance due to execution factors and work definition, as further explained below. The project is forecast to be completed below the AACE Class 3 estimate of $73.1M, which is also discussed below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $31.8M variance above the Plan forecast is primarily attributed to execution factors and work definition, which led to the refinement of work methods to resolve feasibility challenges and to scope increases as the project matured, with cost escalation contributing approximately $15.0M to the variance.

An AACE Class 3 estimate was completed as the project matured, with a net value of $73.1M and an expected outcome range of $58.5M to $95.0M (-20% to +30%). The

investment is forecast to be completed at $2.5M below the AACE Class 3 estimate of $73.1M.

4.1 EXECUTION FACTORS

As the project progressed, it became apparent that the line disconnect switches could not be replaced in situ without taking a double bus outage, directly limiting generation and destabilizing supply for the end customer. To mitigate these impacts, a redesign was required to incorporate a low-profile switch and reconfigure the yard, reducing both customer and generation impacts.

Additionally, more time and effort were required than originally anticipated to stage and coordinate outages with other projects and stations across the transmission system. The increased complexity of outage planning and scheduling resulted in additional project management, engineering, construction, and commissioning effort.

4.2 WORK DEFINITION

A new 115 kV relay building was required as project staging constraints prevented the existing relay building from accommodating new protection and control equipment. As a result, a new protection, telecom and control building was added to the scope at an estimated cost of $10.0M. To reduce the cost impact, the project team proceeded with a prefabricated building as opposed to a conventional brick and mortar structure, reducing project costs by approximately $3.0M.

During detailed project review, it was identified that an additional 12 switches and a significant number of insulators had reached end of life and required replacement to maintain system reliability, contributing $5.0M to the cost increase. These assets were not included in the original project scope and were subsequently added to address emerging asset condition risks, ensuring the reliability of the system and minimizing outages affecting customers and generation.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

Lakehead TS was in the planning phase when the Plan forecast was established, which was based on a high-level scope. The planning phase was undertaken at a level appropriate to support prudent decision-making while avoiding unnecessary costs and schedule impacts associated with extensive early-stage investigations. As the project matured and detailed engineering, constructability assessments, and outage planning advanced, a more comprehensive understanding of operational constraints and customer impacts was developed. At that point, it became evident that the impacts on customers and generation would prevent the project from proceeding as originally planned. An AACE Class 3 estimate was subsequently completed as the project matured, and the project is forecast to be completed below the AACE Class 3 estimate.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance. Outage availability posed a high risk to the project schedule, and this risk was mitigated through regular communication with OPG and the IESO. Additionally, flexibility was built into the project execution plan, providing the option to perform alternative work in case of outage changes. Furthermore, the use of a prefabricated building as opposed to a conventional brick and mortar structure reduced project costs by approximately $3.0M.

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Project Name	Merivale TS Refurbishment
Variance Categories	Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Planning	T-SR-01 T-SS-05	$297.4M	2027
Subsequent Class 3 Estimate			
		$266.3M ($218.4 - $324.9M)[1]	2029
EB-2026-0164			
Execution	T-SR-01 T-SS-05	$284.4M	2029
Variance to EB-2021-0110:		-4%	+2 Years
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Merivale TS Refurbishment was included in the Plan[2] with total net funding of $297.4M and a planned in-service year of 2027, with the project in planning phase. Merivale TS is a Bulk Electricity Station supplying 230 kV and 115 kV load in the Ottawa region. The station has two 230/115 kV autotransformers, a 230 kV Gas Insulated Switchgear (GIS) switchyard and a 115 kV Air Insulated Switchgear switchyard. The primary scope of this investment is to replace end of life assets as well as add new assets to accommodate the Independent Electricity System Operator's (IESO) load growth projects in the Ottawa area by increasing supply capacity.

Currently, the investment is in execution and forecasted to be completed two years later but at $13.0M (4%) below the Plan forecast, but $18.1M above the Association for the

[1] Class 3 estimate accuracy of -18%/+22%
[2] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

Advancement of Cost Engineers (AACE) Class 3 estimate (however within the estimate accuracy range). The AACE Class 3 estimate reflects cost mitigation and execution optimization initiatives implemented throughout detailed engineering, procurement, and construction. This included design refinements, strategic procurement, optimized construction sequences, and execution efficiencies.

This investment will maintain reliable service for Hydro Ottawa and Hydro One customers by addressing aging infrastructure while supporting future capacity requirements, aligning with the IESO's load growth projections for the Ottawa Area.

1.0 SYSTEM NEED

Merivale TS is a Bulk Electricity Station supplying 230 kV and 115 kV load in the Ottawa region. The station's existing transformers and associated facilities have reached end of life and require replacement to maintain reliable service for Hydro Ottawa and Hydro One customers. This investment is the preferred alternative because it replaces aging infrastructure and supports future capacity requirements. Alternative options, such as in-situ replacement and like-for-like replacement, were evaluated and rejected as they would not provide sufficient capacity for forecasted load growth or accommodate the installation of an additional transformer. The selected approach aligns with the IESO's load growth projections for the Ottawa Area by increasing supply capacity while maintaining long-term system reliability.

2.0 PROJECT VARIANCE EXPLANATION (MERIVALE TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, Merivale TS consisted of two separate investments, one within system renewal and the other in system service. However, due to interdependency, the investments were treated as one overall project for execution to achieve cost efficiencies. The System Renewal portion was focused on sustainment and involved replacing one transformer, circuit breakers, associated disconnect switches, and the protections and controls system at Merivale TS. The System Service portion was focused on development to support the continued load growth in the Ottawa West area. To address this need, the investment involved installing a new autotransformer and associated switching facilities as well as modifying and expanding the 230 kV and 115 kV switchyards to connect the new autotransformer.

Currently, the investment is in execution and approximately 79% complete with an in-service date change of two years relative to the Plan forecast. The original planning schedule assumed a more optimistic progression of outages and brownfield work. As detailed execution planning matured, Hydro One determined that brownfield facilities could only be removed from service after replacement facilities were constructed,

commissioned, energized, and demonstrated reliable operation to ensure supply to customers. This required a more sequential implementation strategy than originally assumed. This was driven by complex staging and interdependencies between the two yards, which are further discussed in Section 4.1.

3.0 COST FORECAST AND VARIANCE

The project experienced a cost variance below the Plan forecast, and a schedule delay due to execution factors, which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The current project forecast is approximately $13.0M below the Plan forecast. The cost variance was achieved through a combination of design, contracting, procurement, construction sequencing, and execution optimization measures implemented as the project progressed through detailed engineering, procurement, and execution phases. Several of these approaches were subsequently captured and shared with other Hydro One projects.

4.1 EXECUTION FACTORS

During the planning phase, the final contracting and execution strategy had not yet been determined. As the project progressed through procurement and contract award, Hydro One identified opportunities to implement a more efficient delivery model than originally contemplated. Rather than relying exclusively on a traditional turnkey supply-and-install or engineer, procure, construct model which usually requires a significant premium being paid to the contractor to take on the role, Hydro One employed a separate supply vendor and install general contractor approach to balance risk-reward and improve overall cost competitiveness. Hydro One leveraged a combination of the general contractor and Original Equipment Manufacturer for specialized activities, including SF_6 gas handling, site acceptance testing, and high-voltage testing. This approach improved accountability, reduced execution interfaces between contractor and station operations, increased cost competitiveness, and lowered overall delivery time. Hydro One identified several design optimization measures including transformer spill containment, fire hydrant, laydown yard,

cable trench, and drainage design optimization, as well as reuse of existing facilities, including foundations, that led to cost efficiencies.

The project team collaborated closely with the engineering vendor, equipment suppliers, and contractor to identify opportunities to improve construction sequencing. One example included advancing installation of the gas insulated bus to create parallel work fronts while the GIS building was being constructed rather than following the traditional sequential installation approach. This enabled portions of the work to progress concurrently, improving schedule efficiency by six months and reducing overall construction costs. Similarly, to support customer reliability and operational flexibility, Hydro One interconnected the existing 115 kV east yard and newly constructed 115 kV west yard by resequencing work, enabling portions of the new 115 kV west yard to be energized earlier. This allowed portions of the new infrastructure to be placed into service, reducing carrying costs as well as improving customer supply reliability.

As project planning matured, a more detailed understanding of station staging requirements, outage dependencies, operational risks, and interdependencies between the existing and new facilities emerged. While sequencing improvements recovered approximately six months from the schedule, the benefits were insufficient to fully offset outage constraints, staging requirements, commissioning dependencies, and operational limitations associated with maintaining service to Ottawa-area customers. These factors increased the complexity of the overall execution strategy and contributed to an extension of the project schedule relative to the Plan forecast.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The lower current forecast relative to the Plan forecast was primarily driven by procurement and execution efficiencies identified as the project progressed through detailed engineering and implementation. The procurement outcomes could not have been known until the detailed procurement process was completed. Similarly, the construction sequencing optimizations only became apparent as detailed engineering

progressed and site conditions were fully understood. These measures improved efficiency, reduced rework and construction risk.

Project Name	Wawa TS: Component Replacement
Variance Categories	Execution Factors Reprioritization

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Execution	T-SR-01	$60.1M	2026
EB-2026-0164			
Execution	T-SR-01	$102.2M	2028
Variance to EB-2021-0110:		+70%	+2 Years

Summary:

Wawa TS: Component Replacement was included in the Plan[1] with total net funding of $60.1M and a planned in-service year of 2026, with the project in execution. This investment will replace the end-of-life facilities with new equipment, including autotransformers, breakers, disconnect switches, instrument transformers, oil water separator system, and the alternating current (AC) station service system. The project scope was later revised with additional protection system changes and a full replacement of a Remote Terminal Unit (RTU).

Currently, the investment is in execution and forecasted to be completed $42.1M (70%) above the Plan estimate and two years later, reflecting reprioritization and execution challenges. To mitigate further cost increases, a detailed outage and staging plan was developed and monitored throughout the project to minimize the occurrence and duration of equipment standby hours. Furthermore, to reduce the impact of delivery delays and cost escalations, the project obtained equipment prior to execution. Overall, Hydro One reduced the project cost by approximately $4.0M by lowering construction costs through

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

optimization initiatives such as reduced trenching and excavation and utilizing pre-cast trenches. This investment is necessary to maintain operability and reliability by addressing the deteriorated condition of assets while mitigating environmental risks associated with oil leaks. The upgrades will allow for stronger transfer capability between the northeast and northwest systems in the province.

1.0 SYSTEM NEED

Wawa TS was originally placed in service in 1969 and is a major hub for connecting the northeast, northwest, and Hydro One Sault Ste. Marie LP's transmission systems. Based on condition assessment, the existing equipment is in poor condition and at end of life, requiring replacement to maintain operability and reliability. This investment remains the preferred alternative as it addresses the deteriorated condition of assets within Wawa TS and mitigates equipment failure risk and environmental risk associated with oil leaks. Additionally, the upgrades will result in better transfer capability between the northeast and northwest systems.

2.0 PROJECT VARIANCE EXPLANATION (WAWA TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan estimate, the project scope involved replacing two 230/150 kV autotransformers, 230 kV breakers, 115 kV breakers, disconnect switches, instrument transformers, oil water separator system, and the AC station service system. As the project progressed, the project scope was revised with additional protection system changes, requiring additional drawing updates and engineering effort. Additionally, a full replacement of an RTU was needed (the RTU was originally planned only to be upgraded).

Currently, the investment is in execution and approximately 60% complete with an in-service date change of two years relative to the Plan schedule. This was driven by the reprioritization of projects, which is further discussed in Section 4.1.

3.0 UPDATED COST FORECAST AND VARIANCE

Relative to the Plan estimate, the project experienced a cost and schedule variance due to reprioritization of projects and execution factors which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $42.1M variance is predominantly due to reprioritization and execution factors. The project experienced execution challenges due to input cost increases and project

complexity. Additionally, the project scope increased in response to equipment failure during the project timeline.

4.1 REPRIORITIZATION

The original scope of the project combined 230 kV and 115 kV work to gain efficiencies; however, due to prioritization of the East-West Tie project, which was driven by Independent Electricity System Operator (IESO) requirements, Wawa TS experienced several delays in the planning phase. This put the commitment date to the IESO at risk, and the efficiencies of performing the work under the same project ceased to exist. For these reasons, the separation of the 115 kV scope and 230 kV scope was necessary to in-service the 230 kV portion on time, which has been completed and capitalized. Functionally, the Company treats these two portions as separate investments; however, they are merged here for consistency with the original scope and intent. The reprioritization directly led to an additional $2.0M and 14-month delay due to additional effort for supervision, material management, and revision to the project outage plan, schedule and execution plan. As the East-West Tie project was the primary cause for the delay to the project schedule, it also led to the added cost for material, labour, and incorporation of legislation as listed in Section 4.2.

4.2 EXECUTION FACTORS

<u>Price Increases:</u> Market conditions changed due to significant input price increases for equipment, material, and service contract items, which contributed to the cost variance. In addition, the labour assumptions in the initial estimate proved to be too low. Combined, the market conditions and labour requirements led to an increase of approximately $13.0M.

<u>Project Complexity:</u> The project experienced execution challenges as new soil management legislation came into effect (Ontario Regulation 406/19, *On-Site and Excess Soil Management*, which came into effect in January 2023), leading to additional costs for soil management, testing, and disposal. Additionally, an outage dependent on existing customers was deferred one year as the customer was unable to accommodate the

outage timing. This led to additional requirements for several temporary line bypasses and staging configurations to accommodate multiple outages, which contributed significantly to the cost increase and extended schedule (12-month delay), resulting in additional construction and commissioning efforts. These factors led to an increase of approximately $9.0M. Furthermore, the execution methodology included assumptions regarding underground site conditions, which ultimately led to design changes driven by new information discovered on site during the East-West Tie project, additional foundations identified during execution, and the use of Peri-Forms. The cost of these changes and other design updates led to an additional $3.0M.

The remainder of the variance is attributable to increased contingency and overhead costs. Contingency was added based on an updated risk workshop and probabilistic assessment. The higher contingency covers the high risk of outage delays and cancellations, which are common in the North and can lead to productivity loss and further in-service date delays.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The estimates in the Plan reflected the project's stage of development at the time (being in the execution phase) however, unforeseeable external factors subsequently occurred, causing a cost and schedule variance. As the project was delayed due to the prioritization of the East-West Tie project, execution occurred during a period of high volatility and a surge in demand, which resulted in price increases and extended delivery times. This impact was partially reduced through procuring long lead-time materials. Additionally, regulation changes, an outage deferral due to existing customers, and an RTU failure impacted the project complexity.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance. The remote location of Wawa TS poses a risk of incurring additional standby charges for construction equipment. To mitigate this risk, a detailed outage and staging plan was developed to monitor overall project progress, ensuring various lines of business were aligned. Open and frequent

communication channels were maintained among the lines of business to minimize the occurrence and duration of equipment standby hours. Additionally, the project obtained early approval to order long lead-time materials and finalize engineering drawings, reducing the risk of delays. The project underwent a cost optimization workshop during execution of the work in the 115 kV yard, where opportunities were identified and implemented, including direct burial cable to reduce trenching, the use of a pre-cast trench for a road crossing to reduce concrete costs, reduced excavation by burying telecom cable at a shallower depth, and schedule compression, leading to a reduction in project cost of approximately $4.0M.

Project Name	Rexdale TS: M/C Switchgear & Component Replacement
Variance Categories	Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Execution	T-SR-03	$33.6M	2026
EB-2026-0164			
Execution	T-SR-03	$58.6M	2027
Variance to EB-2021-0110:		+74%	+1 Year

Summary:

Rexdale TS: M/C Switchgear & Component Replacement was included in the Plan[1] with total net funding of $33.6M and a planned in-service year of 2026, with the project in execution. The primary scope of this project is to replace the existing metalclad (M/C) switchgear with medium voltage gas-insulated switchgear (MVGIS), high voltage surge arresters, and a battery charger that are at end of life. Additionally, the investment will install new feeder tie switches and a firewall between the transformers and upgrade the protection and control equipment.

The investment is forecasted to be completed $25.0M (74%) above the Plan estimate and a year later, reflecting a more complex staging plan and construction complexities. Through effective risk management, resource allocation optimization, and partial in-servicing, Hydro One effectively reduced the overall project cost and variance by approximately $6.0M.

This investment is necessary to maintain long-term reliability of supply to Toronto Hydro and its customers by replacing end-of-life assets, reducing risk of operational failure.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

1.0 SYSTEM NEED

Rexdale TS was placed in service in 1989 and facilitates load delivery to Toronto Hydro customers in and around the western Toronto area. This investment remains the preferred alternative as it addresses the equipment failure and operational risk presented by the end of life assets. Not proceeding with this work would have compromised the long-term supply reliability to Toronto Hydro and its customers.

2.0 PROJECT VARIANCE EXPLANATION (REXDALE TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan estimate, the project scope involved replacing the existing 27.6 kV M/C switchgear assets with indoor MVGIS and protection and control systems, along with other required replacements.

Currently, the investment is in execution and approximately 81% complete with an in-service date change of one year relative to the Plan schedule. This was driven by execution challenges, which are further discussed in Section 4.1.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan estimate, the project experienced a cost and schedule variance due to multiple execution factors, which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $25.0M variance is due to execution factors including a more complex staging plan to align with Toronto Hydro's requirements and unforeseen construction complexities related to in-situ equipment replacement.

4.1 EXECUTION FACTORS

<u>Complex Staging Plan</u>: The staging plan was required to align with Toronto Hydro's load forecast and risk mitigation requirements, and several revisions were required during execution. Originally, the plan was to install the switchgear lineup in sequence based on

a preliminary understanding of Toronto Hydro feeder transfer capabilities. The constructability limitations associated with the existing cable arrangements only became apparent as the temporary switchgear configurations were developed and implemented during execution. As a result, this approach proved not feasible during execution because the existing cable arrangement conflicted with the temporary cable routes, limiting the constructability of each stage. Hydro One therefore implemented additional temporary stages that required additional cable pulls, supports, and cable protection to accommodate the cable arrangements between the temporary switchgear configurations. The staging changes also affected the planned use of existing protection and control racks, resulting in further work. Projects involving shared sites with Toronto Hydro, such as Rexdale TS, and containing assets owned and operated by both organizations present unique staging and coordination considerations. As assets reach end of life, there has been an increase in the volume of complex replacement work that necessitates detailed and collaborative planning between the organizations.

<u>Construction Complexities</u>: During execution, Hydro One discovered that the existing duct banks did not have enough space to install the new control cables, which was not apparent from the existing site drawings used for planning. As a result, additional trenches were required to accommodate the new cables. The existing drawings also did not accurately show the locations of some buried cables, which conflicted with the new capacitor switch foundations and had to be relocated. Relying on existing drawings during the planning phase was appropriate, as detailed site reviews and subsurface investigations are typically performed at later stages of project development. Conducting this level of in-depth assessment for every project at the planning stage would be impractical and costly.

As construction progressed, the risk of soil collapse, open trench hazards, and exposure of live power cables required temporary backfilling of trenches while other excavation activities were completed nearby. Frequent and heavy rainfall also impacted site conditions, resulting in unstable excavations that required temporary shoring to safely stabilize the excavations.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The estimate in the Plan reflected the project's stage of development at the time (being in the execution phase) however, unforeseeable external factors occurred afterwards, causing a cost and schedule variance. The variance arose from a combination of site-specific factors, including constraints associated with existing equipment locations, soil conditions, and weather-related impacts encountered during construction. Additional effort was required to adapt the execution approach in response to the site conditions, ensuring work could be completed safely.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance. Through proactive risk management, optimization of resource allocation to mitigate overtime, effective contract management that recovered a claim from a vendor, and partial in-servicing of equipment, Hydro One effectively reduced the overall project cost by approximately $6.0M.

Project Name	Lake TS: T2 & Component Replacement
Variance Categories	Work Definition

Variance Summary

Project Phase	ISD Reference	Project Total ($M)	In-Service Year
EB-2021-0110			
Planning	T-SR-03	$39.9M	2026
Subsequent Class 3 Estimate			
		$57.1M ($45.7M - $74.2M)	2028
EB-2026-0164			
Complete	T-SR-03	$11.9M	2024
Variance to EB-2021-0110:		-70%	-2 Years
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Lake TS: T2 & Component Replacement was included in the Plan[1], with total net funding of $39.9M and a planned in-service year of 2026, with the project in planning phase. The primary scope of this investment is to replace three end of life transformers and associated equipment. The project was later descoped when the opportunity to purchase an adjacent property became available, which was assessed and determined to provide significant benefits by improving construction efficiency, enhancing site safety, and supporting future load growth opportunities. This reflects Hydro One's ability to make agile and prudent decisions as new information becomes available, adapting the project strategy to improve safety, reduce risks, optimize future investment requirements, and deliver value for Ontario customers.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

The investment was completed two years ahead of the Plan schedule and $28.0M (70%) below the Plan forecast, reflecting significant scope refinement. This investment improves system reliability, supporting Hydro One's commitment to customers through upgraded infrastructure while reducing environmental risks.

1.0 SYSTEM NEED

Lake TS has three 115/44 kV 75/125 MVA step down transformers connecting it to the 115 kV and 44 kV system. The station is a load supply, regulating, and auto-transformer station, supplying approximately 277 MW of load. Lake TS supplies HP (1 customer in Ontario), sub-transmission stations, and other customers including the City of Windsor via three 13.8 kV feeders. The station was placed in service in 1954 and supplies Alectra Utilities, in the City of Hamilton, via two switchyards. The existing assets are at end of life, showing signs of aging and degradation. This investment was the preferred alternative as it improves system reliability, supporting Hydro One's commitment to customers through upgraded infrastructure.

2.0 PROJECT VARIANCE EXPLANATION (LAKE TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing three transformers and their related equipment. Subsequently, the project was descoped. Early in the project execution phase, Hydro One was approached by a neighbouring property owner regarding the potential sale of adjacent land. At the same time, the project team identified significant execution challenges associated with completing the work within the existing station footprint. These challenges included the need to procure and install a spare transformer to facilitate the replacement of the T3 and T4 transformers. Given the identified execution constraints, the anticipated future work associated with the 13.8 kV metalclad replacement, and the safety risks of performing construction activities within a highly congested site, Hydro One proceeded with the property acquisition to provide additional space for both current and future station needs. The project scope of work for the investment was revised to replace one transformer and its associated components, in addition to the replacement of a station service transformer.

The investment was completed in 2024, two years ahead of schedule relative to the Plan schedule.

3.0 UPDATED COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project experienced a cost and schedule variance due to work definition maturity, which is further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $28.0M variance below the Plan forecast is attributable to increased work definition maturity, which resulted in several scope changes. In particular, the opportunity to acquire adjacent property became available, enabling Hydro One to improve project execution efficiency, enhance site safety, and create future load growth opportunities. A comprehensive assessment of these factors, including a financial analysis demonstrating that the property acquisition would reduce costs associated with the T3 and T4 transformer replacements, confirmed that this was the appropriate path forward.

4.1 WORK DEFINITION

Originally, to replace two of the transformers, a temporary transformer, which would have been kept as an operating spare afterwards, was required due to stranded load and system operating requirements. However, after the project went into execution in 2023, the adjacent property was listed for sale. After analyzing the existing project plan and the new opportunity, it was determined that deferring the replacement of the two transformers slightly and acquiring the property was the appropriate choice. The purchase would allow the two new transformers to be installed without a temporary one and significantly reduce safety, staging, and outage risks, as well as provide future flexibility for the expected load growth in the region. As a result of the land acquisition, the scope of work for the two transformers was removed from this investment and became part of a separate investment

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The project was in a planning phase when the Plan forecast was established. At the beginning of the project execution phase, Hydro One became aware that the neighbouring property would be made available for sale, changing the circumstances and providing an alternative to reduce execution risk, improve safety, and provide greater value to customers.

Project Name	D6 Transmission Line Refurbishment
OEB File No.	EB-2026-0112
Variance Categories	Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Execution	T-SR-13	$42.8M	2025
EB-2026-0164			
Execution	T-SR-13	$72.7M	2028
Variance to EB-2021-0110:		+70%	+3 years

Summary:

D6 Transmission Line Refurbishment was included in the Plan[1] with total net funding of $42.8M and a planned in-service year of 2025, with the project in execution. The primary scope of this investment was to refurbish 77 km of circuit between Des Joachims TS and Petawawa/Craig DS.

Currently, the investment is in execution and forecast to be completed $29.9M (70%) above the Plan estimate and three years later, reflecting a change in the execution method from in situ refurbishment to greenfield relocation work for a 29 km portion of the line due to Department of National Defence (DND) restrictions on access to the existing corridor. To reduce further schedule impacts, Hydro One incorporated schedule contingency to address the risk of outage cancellations and delays in obtaining third-party approvals. In addition, design and execution optimization initiatives were implemented, including abandonment of certain idle facilities and utilizing steel poles where possible to avoid an additional $6.0M in costs, reducing the impact on Ontario ratepayers. As a result, the current variance is approximately $29.9M relative to the Plan estimate.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

This investment improves safety and reliability by addressing end of life assets, providing sustained service to crucial customers, and enhancing system resilience. It will improve asset durability, reduce vulnerability to environmental conditions, and ameliorate access to infrastructure.

1.0 SYSTEM NEED

The D6 circuit between Des Joachims TS and Petawawa/Craig DS was constructed in the 1940s and operates on end-of-life assets. This investment remains the preferred alternative as it addresses safety and reliability risks, sustains service to customers, and enhances system resilience. Replacing aging wood poles improves asset durability and reduces vulnerability to environmental conditions. The relocation of a portion of the line also provides significantly improved access, supporting more efficient maintenance, fault investigation, and service restoration.

2.0 PROJECT VARIANCE EXPLANATION (D6 TRANSMISSION LINE REFURBISHMENT)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan estimate, the project scope involved refurbishing 77 km of the 115 kV circuit between Des Joachims TS and Petawawa/Craig DS in-situ. This included replacing approximately 350 poor condition wood poles with new composite poles where easement rights allow, and otherwise with new wood poles. In addition, the scope included completion of the fibre optic communication channel between Des Joachims TS and Pembroke TS, which involved a 14 km section requiring structure replacements and stringing of optical ground wire (OPGW).

Currently, the investment is in execution and approximately 53% complete, with an in-service date change of three years relative to the Plan schedule. This was driven by execution challenges that required the project to be paused and reassessed, as further discussed in Section 4.1.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan estimate, the project experienced a cost and schedule variance due to execution factors, as further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $29.9M variance above the Plan estimate is attributed to execution factors, which required 29 km of the original route to be relocated due to DND corridor access restrictions, resulting in the in situ refurbishment changing to greenfield relocation work, as well as additional equipment to support uninterrupted power supply during construction.

4.1 EXECUTION FACTORS

D6 Circuit Relocation: Originally, the 77 km refurbishment was to be completed in situ, including the 29 km section traversing the DND land. After ongoing discussions regarding the status of the line portion crossing the military base, DND issued a letter denying access under the Defence Controlled Access Area Regulations and advised that it could not provide the continuous and unrestricted access required and supported relocating the line to a new location along Highway 17, off active DND land. This request placed the project on hold as detailed reviews were conducted. After exploring the available options, it was determined that the relocation of this portion of the work would require a Section 92 “Leave to Construct” (LTC) application to the Ontario Energy Board (which is ongoing - EB-2026-0112),[2] and that new land rights needed to be acquired, further delaying the project. This led to higher costs related to design, construction needs such as access roads, forestry, real estate, interest and overhead charges. The relocation added approximately $26.0M to the overall project cost but enables safe, reliable, and significantly improved access to this line segment.

Customer Power Supply: During the construction period, customer power supply requirements were higher than expected, requiring temporary generators to be deployed at Craig DS and Petawawa DS to ensure uninterrupted service, resulting in approximately $3.0M of additional costs. Further costs were incurred in execution as outage constraints required construction of a new lattice structure ahead of the existing junction to maintain service continuity, resulting in design adjustments.

[2] The Section 92 Leave to Construct application (EB-2026-0112) is in respect of the greenfield relocation. The completed in-situ refurbishment and greenfield relocation form part of the overall D6 Transmission Line Refurbishment project presented herein.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

At the time of project planning, Hydro One's scope was based on an in-situ refurbishment of the existing D6 corridor, including the section crossing DND lands. Hydro One held the necessary easement rights to operate and refurbish the transmission line within the existing corridor. While DND had previously expressed an interest in relocating the line, no formal requirement had been issued.

The relocation could not have been reasonably contemplated at the time of planning because the project was developed based on the information available at the time, which supported continued use and refurbishment of the existing corridor. Subsequently, DND's position evolved and in June 2023, the DND formally advised Hydro One that access to portions of the military base would be restricted and requested relocation of the transmission line outside active military lands. This directive fundamentally changed the project from refurbishment of an existing transmission asset to the development of a new transmission corridor.

As a result of the DND's decision, Hydro One was required to pause the project, reassess alternatives, undertake new engineering work, undertake environmental and regulatory studies, acquire new land rights, establish a new route along Highway 17, interface with the Ministry of Transportation (MTO) to ensure the route was fit for purpose for all parties, and initiate a Section 92 LTC application (EB-2026-0112). These requirements arose from a third-party decision that was outside Hydro One's control and were not known at the time of planning.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance. To address the risk of outage cancellations and delays associated with third-party approvals, including the Section 92 LTC and Environmental Assessment approvals, a six-month schedule contingency was integrated into the schedule. In addition, Hydro One implemented design and execution optimization initiatives. These included negotiating abandonment in place

of approximately 17 km of idle facilities and adopting more cost-effective design solutions such as utilizing steel poles in place of lattice structures where feasible. These measures resulted in approximately $6.0M in avoided costs to the project.

Project Name	Preston TS: T3, T4 & Component Replacement
Variance Categories	Work Definition Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total ($M)	In-Service Year
EB-2021-0110			
Planning	T-SR-03	$23.7M	2026
Subsequent Class 3 Estimate			
		$55.4M ($44.3M - $72.0M)	2027
EB-2026-0164			
Execution	T-SR-03	$47.0M	2027
Variance to EB-2021-0110:		+98%	+1 Year
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Preston TS: T3, T4 & Component Replacement was included in the Plan[1], with total net funding of $23.7M and a planned in-service year of 2026, with the project in the planning phase. The primary scope of this investment is to replace end of life assets, including two transformers, associated equipment, and protections. The project scope later increased to accommodate a greenfield transformer replacement to ensure continuity of supply critical to the region.

Currently, the investment is in execution and is forecast to be completed $23.3M (98%) above the Plan forecast and one year later, but $8.4M below the Association for the Advancement of Cost Engineers (AACE) Class 3 estimate and on schedule. The AACE Class 3 estimate reflects the updated greenfield approach and cost escalations caused by

market conditions. The latest forecast reflects reductions achieved through schedule acceleration, scope and in-service optimization, construction efficiency improvements, and effective risk management.

This investment maintains reliability of power supply in the Cambridge area by addressing end of life assets while increasing supply out of the station, aligning with the load growth projections in the area.

1.0 SYSTEM NEED

Preston TS was built in 1968 and supplies approximately 105 MW of power to GrandBridge Energy, supplying the Kitchener-Waterloo-Cambridge-Guelph region. The current assets are in poor condition and need to be replaced to maintain reliability of power supply in the Cambridge area. This investment remains the preferred alternative as it addresses the risks associated with the end of life equipment failure and enables Hydro One to increase supply out of Preston TS to accommodate the Independent Electricity System Operator load growth projections in the area.

2.0 PROJECT VARIANCE EXPLANATION (PRESTON TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing two transformers, multiple protections, disconnect switches, surge arresters, neutral grounding reactors, and protection and control equipment. Subsequently, the project scope increased to accommodate a greenfield transformer replacement, as well as other required upgrades.

Currently, the investment is in execution and approximately 88% complete, with an in-service date one year later than the Plan schedule. This was driven by changes to the project requirements, which are further discussed in Section 4.1.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project total cost is higher due to work definition maturity and execution factors, which are further explained below. However, the current forecast is below the AACE Class 3 estimate and on schedule.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $23.3M variance above the Plan forecast is attributed to work definition maturity and execution factors whereby market conditions impacted the execution of the project as commodity costs increased, in particular the cost of the transformers.

An AACE Class 3 estimate was completed with a net value of $55.4M and expected outcome range of $44.3M to $72.0M (-20% to +30%). The investment is forecast to be completed $8.4M below the AACE Class 3 estimate of $55.4M. This was achieved through schedule acceleration, scope and in-service optimization, construction efficiency improvements, and effective risk management.

4.1 WORK DEFINITION

As the project matured, a major outage risk with replacing the transformers in situ drove the project to explore other options. Due to the station's configuration, replacing both transformers in situ would require station-wide outages. Given the critical nature of the station's dual supply contingency to the region and customers, rejection of these outages was highly likely. Additionally, the station connects to the 115 kV F/C circuits and provides the bridge between the 230 kV and 115 kV systems.

As such, it was determined that replacement of one of the transformers in a greenfield location was required to ensure continuity of supply critical to the region. This would require two new medium-voltage breakers and associated disconnect switches with complete bus work. To ensure compliance with applicable standards, a new firewall was required between the transformer closest to the relay building. In addition, the DC system needed to be upgraded given the protection and transformer replacements, which also led to the need for a relay room extension.

Finally, additional protection, control and telecom requirements were incorporated due to the obsolescence of the existing equipment. The above-noted scope additions, collectively contributing approximately $16.0M to the variance, were required to ensure safety and constructability were maintained while balancing the ability to secure outages.

4.2 EXECUTION FACTORS

The project cost was also impacted due to constrained supply chains causing input cost escalation on the transformer and other major procurements, totaling approximately $7.0M.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

The project was in a planning phase when the Plan forecast was established. As the project matured, it was determined that the dual supply contingency at the station could not be risked due to the presence of many regionally critical customers supplied from this station without alternative supply availability. A greenfield approach mitigated this risk while allowing replacement of the critical end of life transformers and other components to improve reliability and meet growing demand. An AACE Class 3 estimate was completed subsequently, with the project currently forecasting below the estimated value, as further discussed above in Section 4.0. This aligns with Hydro One's Capital Project Delivery Model in terms of project-level maturity.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance and to help mitigate further variance relative to the Plan forecast. Hydro One has a robust capital project delivery model in place with defined stage-gate points to ensure that the most cost-effective and prudent solutions in the interest of customers are pursued. In this case, even though the scope had increased significantly, it was done to the ultimate benefit of customers. To mitigate risk associated with fluctuations in raw commodity prices in the global market, the transformers were ordered through long-lead-time material funding during the planning phase to help reduce price increases. Additionally, regular meetings with the customers were arranged to discuss changes in the electrical system or their needs to lessen the impact on planned outages.

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Project Name	Moose Lake TS: Component Replacement
Variance Categories	Work Definition Reprioritization

Variance Summary

Project Phase	**ISD Reference**	**Project Total**	**In-Service Year**
EB-2021-0110			
Planning	T-SR-03	$9.6M	2027
Subsequent Class 3 Estimate			
		$32.5M ($26.0M - $42.3M)	2028
EB-2026-0164			
Execution	T-SR-03	$30.6M	2028
Variance to EB-2021-0110:		+219%	+1 Year
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Moose Lake TS: Component Replacement was included in the Plan[1], with total net funding of $9.6M and a planned in-service year of 2027, with the project in planning phase. The primary scope of this project is to replace an end of life power transformer, breaker, switches, instrument transformers, and protection, control and telecom (PCT) equipment. Concurrently, this project will also reconfigure the 44 kV facility to complement the development work of the new 44 kV facility at Mackenzie TS, which is a supply point to Atikokan Hydro. The project scope later increased to include alternating current (AC) switchgear, greenfield control building work, station fence refurbishment, and a new spill containment technology.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

Currently, the investment is in execution and forecast to be completed $21.0M (219%) above the Plan forecast and a year later, but $1.9M below the Advancement of Cost Engineers (AACE) Class 3 estimate and on schedule. The AACE Class 3 estimate reflects scope refinement as the project matured and portfolio reprioritization. The latest forecast reflects reductions through effective risk-management strategies that limited the use of project contingency funds, reducing the overall project cost by approximately $1.9M. The project team further mitigated the schedule impacts by maintaining a flexible and outage-ready execution strategy, allowing work to proceed as outage opportunities became available.

This investment will improve reliability by addressing deteriorated assets, allowing the station to support other major projects in the area while reducing environmental risks.

1.0 SYSTEM NEED

Moose Lake TS supplies Ontario Power Generation at the nearby Atikokan Generating Station and the local distribution company of Atikokan Hydro; however, an equipment health assessment of Moose Lake TS in 2016 identified multiple end of life assets. This investment remains the preferred alternative as it addresses the deteriorated condition and obsolescence of the various assets, improving the station's ability to proceed with other major outage-related projects in the area and become more eco-friendly. Not proceeding with this project would have resulted in system reliability risks and compromised transmission capacity in the area.

2.0 PROJECT VARIANCE EXPLANATION (MOOSE LAKE TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing one transformer, one circuit breaker, switches, instrument transformers, PCT equipment, and other required equipment. Subsequently, the project scope increased to include AC switchgear, greenfield control building work, station fence refurbishment, and piloting a new spill containment technology.

Currently, the investment is in execution and approximately 33% complete, with an in-service date change of one year relative to the Plan schedule due to the reprioritization of the project, which is further discussed in Section 4.2.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project total cost is higher however due to work definition maturity and reprioritization of the portfolio, which are further explained below. However, the current forecast is below the AACE Class 3 estimate and on schedule.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $21.0M variance above the Plan forecast is due to work definition maturity, resulting in scope changes and quantity adjustments. Updated labour assumptions, higher

procurement costs, interest, and overhead contributed to the variance as well. Additionally, the investment was also affected by portfolio reprioritization.

An AACE Class 3 estimate was completed with a net value of $32.5M and expected outcome range of $26.0M to $42.3M (-20% to +30%). The investment is forecast to be completed $1.9M below the AACE Class 3 estimate of $32.5M.

4.1 WORK DEFINITION

Moose Lake TS: Component Replacement experienced multiple scope changes as the project matured, contributing approximately $9.0M to the cost increase. After the field walkthrough, numerous drawing revisions were required to ensure the design accurately reflected site details and conditions. Additional scope was added, including AC switchgear and greenfield control building work, which required additional relay replacements and relocation of relevant protection equipment to vacate the existing protection and control room.

As the project evolved and asset conditions were continually assessed, it was determined that the aging station service equipment needed to be replaced to maintain a reliable standard. Furthermore, a new spill containment technology was piloted in this project. This solution uses smart fabric technology that allows rainwater and snow to melt through while capturing oil spills and leaks, decreasing the cost of cleanup. The original plan assumed re-using the existing spill containment system, which ultimately proved not feasible. As Hydro One continues to adopt this new technology, savings will be realized as it is cheaper to install with less excavation and can be done without interrupting service in both brownfield and greenfield projects. Ultimately, this solution is cheaper than the traditional concrete spill containment. Furthermore, fence restoration and associated animal mitigation measures were undertaken to ensure compliance with operational and environmental requirements.

Input cost escalation was also a contributor to the variance, with approximately $4.0M of additional costs attributable to increased procurement costs. Furthermore, the project cost

was also impacted by updated labour assumptions and quantity adjustments for certain components. Additional cost impacts were driven by the inclusion of supplementary civil works and equipment removal activities required to establish safe access to the site.

4.2 REPRIORITIZATION

Moose Lake TS: Component Replacement was on hold between 2021 and 2024 due to portfolio reprioritization. When the project resumed, three other major projects were in execution simultaneously in the Northwest Ontario zone. This reduced the availability of outages and restricted the continuity of work, leading to extended construction and commissioning timelines and increased costs. The outage plan was revised close to the end of the planning phase as outage plans matured for the other three projects, impacting the cost and schedule. Delays were minimized through a flexible and outage-ready execution strategy, allowing work to proceed as outage opportunities became available, through an increased construction crew size, and the use of pre-built equipment racks.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

Moose Lake TS was on hold and in the planning phase when the Plan forecast was established. When the project restarted, multiple revisions to the scope and execution were required to incorporate the latest information regarding other major projects and new technology. An AACE Class 3 estimate was subsequently completed, with the project currently forecast below the AACE Class 3 estimate.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance. To mitigate risk of outage restrictions and limited schedule flexibility should an outage change occur due to the other priority projects in the area, protection relays will be installed and pre-commissioned, ready for any outage that becomes available. In addition, overtime effort has been incorporated into the execution work plan to ensure transformer replacement work can be completed within the outage window. Furthermore, monthly meetings were established with major vendors to reduce the risk of delivery delays. By applying effective risk-

management strategies that limited the use of project contingency funds, Hydro One effectively reduced the overall project cost by approximately $1.9M.

Project Name	Essa TS: T3 & Component Replacement
Variance Categories	Execution Factors

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Planning	T-SR-01	$88.1M	2027
Subsequent Class 3 Estimate			
		$88.3M ($72.4M - $112.1M)	2026
EB-2026-0164			
Complete	T-SR-01	$70.3M	2026
Variance to EB-2021-0110:		-20%	-1 Year
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Essa TS: T3 & Component Replacement was included in the Plan[1] with total net funding of $88.1M and a planned in-service year of 2027, with the project in the planning phase. The primary scope of this investment is to replace a 500/230 kV autotransformer unit, station service transformer, disconnect switches, a breaker, the oil water separator system, alternating current (AC) station service system and construction of a new 500 kV building.

The investment was substantially completed a year ahead of schedule and $17.8M (20%) below the Plan forecast, reflecting proactive risk management, effective contract management, construction efficiencies, and advanced in-servicing.

Essa TS: T3 & Component Replacement improves reliability to the bulk electric system by prioritizing replacement of the high-risk transformer.

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

1.0 SYSTEM NEED

Essa TS is located west of Barrie and connects the northern and southern parts of the grid. An asset risk assessment identified that the T3 autotransformer was in poor condition and approaching a state of high risk to the reliability of the bulk electric system. This investment was the preferred alternative as it prioritized transformer replacement to address reliability risks.

2.0 PROJECT VARIANCE EXPLANATION (ESSA TS: T3)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing a 500/230 kV autotransformer unit, station service transformer, disconnect switches, a breaker, the oil water separator system, AC station service system, and the construction of a new 500 kV building. Proactive risk management and effective cost optimization strategies have resulted in the investment being completed significantly under the Plan forecast and a year earlier than the Plan schedule.

This investment was separate from the related ABCB replacement project at Essa TS to expedite the replacement of T3, which was deemed a priority for system reliability.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project total cost is lower and the schedule improved due to execution factors, which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $17.8M variance below the Plan forecast was achieved by reducing the impact of execution factors through effective risk management and advanced in-servicing, lowering contingency and interest costs. Effective contract management minimized the cost of the relay building, and construction efficiencies were realized throughout the project. Proactive risk management and effective resource use resulted in significantly lower contingency use and construction costs.

An AACE Class 3 estimate was completed with a net value of $88.3M and expected outcome range of $72.4M to $112.1M (-18% to +27%). The level of project maturity and actualized costs at the time provided a slightly narrower range than a typical Class 3 estimate. The investment was completed $18.0M below the AACE Class 3 estimate of $88.3M.

4.1 EXECUTION FACTORS

Through effective contract management, execution efficiency, and project acceleration, Hydro One successfully reduced the cost of the project. Contract management lowered the price of the transformer and the cost of completing the building, which was finished ahead of schedule. The latter was a risk when the project entered execution as the Engineer, Procure, Construct (EPC) contract was based on technical specifications, and unanticipated or unknown conditions could result in extra costs. This was mitigated through proactive monitoring and control of the EPC contract. Another risk regarding soil disposal did not materialize as it was clean when excavated, further lowering contingency usage. The soil could be reused and the use of hydrovac excavation was reduced, decreasing construction costs for civil work. Furthermore, construction costs were reduced as the expected crew sizes for the work were lowered. In addition, completing transformer oil filling earlier than planned and in-servicing the transformer approximately five months ahead of schedule avoided costs associated with storage and decreased carrying costs, resulting in substantial project savings.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

Essa TS: T3 was in the planning phase when the Plan forecast was established. As the project matured, an AACE Class 3 estimate was completed with the project being completed below the estimated value as further discussed above in Section 4.0.

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Project Name	Essa TS: 500kV ABCB & Component Replacement
Variance Categories	Execution Factors Work Definition

Variance Summary

Project Phase	ISD Reference	Project Total	In-Service Year
EB-2021-0110			
Planning	T-SR-02	$75.9M	2028
Subsequent Class 3 Estimate			
		$109.4M ($87.5M - $142.2M)	2030
EB-2026-0164			
Execution	T-SR-02	$107.2M	2030
Variance to EB-2021-0110:		+41%	+2 years
Alignment with Class 3 Estimate:		Yes	Yes

Summary:

Essa TS: 500kV ABCB & Component Replacement was included in the Plan[1] with total net funding of $75.9M and a planned in-service year of 2028. At that time, the project was in the planning phase with a focus on replacing all 500 kV air blast circuit breakers (ABCBs) with sulfur hexafluoride (SF_6) breakers, as well as associated tertiary equipment, isolation switches, and the alternating current station service supply. Existing protection and control facilities would be replaced as well. The project scope later increased slightly to include a disconnect switch and protection upgrades.

Currently, the investment is in execution and forecast to be completed $31.3M (41%) above the Plan forecast and two years later, reflecting the complexity of the execution staging plan due to an anticipated customer connection project occurring at the same time and cost escalations influenced by market conditions. These developments were captured

[1] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

in the Association for the Advancement of Cost Engineers (AACE) Class 3 estimate, and the project is forecast to be completed below the estimate. This was achieved through execution and design optimizations, which reduced the total cost and variance by approximately $3.0M. Additionally, to mitigate further schedule impacts due to outage cancellations, ongoing communication with the appropriate stakeholders will occur to minimize the likelihood of rescheduling.

This investment at Essa TS improves system operability and reliability by addressing asset conditions and deficiencies, reducing the risk of equipment failure and expensive complex maintenance.

1.0 SYSTEM NEED

Essa TS serves a crucial node where the Northern portion of the transmission grid ties into the Southern portion. An assessment conducted in 2020 identified select assets and infrastructure at Essa TS that required replacement to address asset conditions and deficiencies that may affect system operability and reliability. This investment remains the preferred alternative as it addresses the poor condition of the assets and reduces the risk of equipment failure and expensive maintenance.

2.0 PROJECT VARIANCE EXPLANATION (ESSA TS)

2.1 PROJECT OVERVIEW AND STATUS

In the Plan forecast, the project scope involved replacing 500 kV ABCBs, associated switches, and other assets in poor condition, as well as protection and control system upgrades. Subsequently, the project scope increased slightly to include an additional 230 kV disconnect switch and protection upgrades.

Currently, the investment is in execution and is approximately 21% complete, with an in-service date change of two years relative to the Plan schedule. This was driven by competing outages, which are further discussed in Section 4.2.

3.0 COST FORECAST AND VARIANCE

Relative to the Plan forecast, the project experienced a cost and schedule variance due to execution factors and work definition maturity, which are further explained below.

4.0 WHY THE VARIANCE OCCURRED (KEY COST DRIVERS)

The $31.3M variance above the Plan forecast is due to execution factors and work definition maturity. Material and labour cost increased, and additional contingency was added to the forecast due to heightened execution risk from an anticipated customer connection project happening at the same time, which could significantly impact the staging of this project. Furthermore, the complexity of the execution staging plan and minor scope increase, which included one disconnect switch and 230 kV protection

upgrades (which were identified as being in poor condition during the emergency replacement of the T4 transformer under a demand replacement program), impacted the cost and schedule as well.

An AACE Class 3 estimate was completed with a net value of $109.4M and an expected outcome range of $87.5M to $142.2M (-20% to +30%). The investment is forecast to be completed $2.2M below the AACE Class 3 estimate.

4.1 EXECUTION FACTORS

Execution factors account for approximately $12.0M of the variance relative to the Plan forecast, including volatility in the global supply chain, which resulted in a substantial cost increase for the project materials, including the 500 kV breakers, which are highly specialized and in-demand equipment, as well as input cost escalation.

4.2 WORK DEFINITION

Essa TS is in Central Ontario and ties the Northern portion of the grid to the Southern portion. Securing system outages at Essa TS requires significant planning and is susceptible to unanticipated cancellations and changes. The replacement of the 500 kV breakers requires extensive coordination with other planned and unplanned work in the area, including ongoing repairs at Claireville TS, which connects to Essa TS, transmission line modification work for third parties, and various other projects. The resultant outage plan changes impacted project staging, timelines, and costs (approximately $9.0M of the variance) and required the adjustment of workforce and equipment during project downtime.

Furthermore, designs were further refined, including access roads, cable trenches, and other details, accounting for approximately $3.0M of the variance, along with a more thorough assessment of risk, which resulted in increased contingency (approximately $4.0M of the variance). Minor additional scope was also added to the project, which included one 230 kV disconnect switch and protection upgrades, contributing approximately $3.0M to the variance.

5.0 WHY THE VARIANCE COULD NOT HAVE BEEN REASONABLY CONTEMPLATED AT APPROVAL

Essa TS was in the planning phase when the Plan forecast was established. As the project matured, an AACE Class 3 estimate was completed, with the project currently forecasting below the estimated value, as further discussed above in Section 4.0.

6.0 MITIGATION ACTIONS AND IMPROVEMENTS

The following actions have been taken to minimize the variance and to help mitigate further variance relative to the Plan forecast. To mitigate the risk and impact of outage cancellations, the outage plan was reviewed and approved by the appropriate stakeholders and ongoing communication will occur to minimize the likelihood of rescheduling due to operating requirements. In addition, several mitigation actions contributed to reducing the total cost by approximately $3.0M. These actions included execution and design optimizations, such as reusing existing foundations and excavated soil, and procuring pre-built relay racks.

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BY EMAIL AND RESS

January 18, 2023

Mr. Alex Share
Manager of Generation & Transmission
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Share,

EB-2020-0265 – Hydro One Networks Inc. Section 92 – Hawthorne to Merivale Reconductoring Project - Update on Project Cost

In accordance with the Ontario Energy Board's ("OEB") Decision and Order, regarding Hydro One's leave to construct application for the Hawthorne to Merivale Reconductoring Project ("HMR Project" or "Project"), dated April 22, 2021, Hydro One is providing the OEB with an update regarding an increase in Project cost. The Project in-service date is not expected to change from that approved in Hydro One's application, namely December 2023. The revised Project forecast cost is $46.9 M versus $21.3M (total project cost forecast inclusive of removals) approved in EB-2020-0265. The cost variance will be managed via Hydro One's Redirection Process within the OEB-approved transmission capital envelope.

The current Project forecast estimate of $46.9M was derived from applying the Association for Advancement of Cost Engineering (AACE) Class 2 (+20% / -10%) principles and processes. The Project is now approximately 50% complete which has resulted in the elimination of some of the execution risks that were considered and included in the Project's s.92 Application prior to construction commencement, such as: the completion of project designs, completion for the scope of the M31A line replacement, OPGW installation. Additionally, all major project materials have now been sourced and acquired.

Hydro One has informed the IESO of the progress of this Project with respect to cost and schedule and will continue to do so. The IESO confirmed this Project remains the appropriate option to proceed with and the forecast cost increase does not change the preferred transmission alternative. The HMR Project remains the preferred alternative, consistent with the options considered and analysis provided in Hydro One's S.92 Application at Exhibit B, Tab 5, Schedule 1. The HMR Project, as approved by the OEB, will provide benefits consistent with the evidence provided to the OEB during the S.92 leave to construct hearing, being; increased reliability and adequate of capacity.

The updated Project cost forecast will increase a typical 2020 residential customer's monthly bill[1] by $0.04 per month, to $181.62[2] using the same average consumption assumptions used by the OEB at the time Hydro One filed the S.92 Application. The updated Project cost impact on a typical customer bill in 2023, based on the OEB-approved average residential consumption of 750 kWh, would be an increase of $0.02 per month to $134.54[3]. Both scenario's updated comparative information detail is provided below in **Tables 1 and 2** of **Appendix A.**

The cost variance is attributable to the following factors:

Drivers of the cost increase:

- **A higher than anticipated cost for re-stringing the conductor** ($12.0M) - The conductor restringing execution element was more complex than originally planned due to the dual-bundled conductor configuration being used, combined with the size/weight of the 1443 kcmil conductors being bundled. Increased labour costs due to the project execution methods, limitations to anticipated outage windows, and additional labour for the operation of more specialized restringing equipment necessary for the Project's unique conductor configuration increased costs by $4.0M.

  Due to the size and complexity of the conductor configuration of the circuits an additional $8.0M of equipment rental costs are forecast. The unique conductor size and the bundled nature of the design, require the rental of specialty equipment for installation activities. The forecast included in the s.92 Application assumed Hydro One's own equipment would be used, however, as the Project execution plan matured, it was deemed inadequate due to equipment reach and load capacity limitations. Specialty equipment, such as Bronto Skylifts, and aerial devices were needed to assist with the stringing preparation. Other stringing equipment associated with public safety was also deemed essential due to the use of this specialty equipment and project being sited in a major urban area (i.e. City of Ottawa). This resulted in additional boom tip rider costs, rental of a 40-tonne boom-truck. and rental for a Hydrovac truck for hole excavation which was used to construct the temporary safety rider poles installation throughout the transmission line corridor.

- **Additional costs for tower reinforcements** ($3.8M) - A dual-bundled heavier conductor (i.e. 1443 kcmil) was installed to accommodate the required capacity increase on these lines, as approved. This required additional steel reinforcement on all 94 transmission lattice towers as the existing towers were designed for a single conductor per phase. The cost estimate included in the s.92, included preliminary engineering design and did not account for the extent of these tower

[1] When utilizing Hydro One's R1 rate class and the OEB-approved 2020 rates and demand factors (i.e. Residential R1 at 920 kWh per month at Tiered prices). For comparative purposes this remains consistent with the category of customer and per month kWh usage incorporated in the analysis by Hydro One in the original analysis, as presented in Exhibit B, Tab 1, Schedule 9, pg.3.
[2] Appendix A, Table 1, Row A, Average monthly bill amount of $181.58, plus, the $0.04 increase resulting from the updated project forecast costs = $181.62 per month.
[3] Appendix A, Table 2, Row A, Average monthly bill amount of $134.52, plus, the $0.02 increase resulting from the updated Project forecast costs = $134.54 per month.

reinforcements as later identified in the final design/drawing package released for construction. Additionally, increased labour costs were incurred to perform the tower reinforcement work that was condensed and undertaken in the spring and fall season outage windows. The increase in those above-described costs, inclusive of additionally steel tower reinforcement is approximately $2.4M. Furthermore, specialty hire equipment was required to execute the steel tower reinforcement work on the higher sections of the transmission towers, at an additional cost of approximately $1.4M.

- **Additional cost of a construction / laydown area complex** ($2.2M) - The Project plan incorporated into the OEB-approved S.92 assumed the utilization of space at either Merivale TS and/or Hawthorne TS for material storage, assembly and project execution. However, due to the ongoing Hydro One work in eastern Ontario and the project development of the Merivale TS refurbishment project, the space available inside the two prior-mentioned stations was constrained to a point that was insufficient to accommodate this Project's requirements. In response, Hydro One negotiated a lease on a suitable property adjacent to Albion TS, for the project's duration. This almost 5-acre land is ideally suitable for the Project's marshaling yard and construction complex, is adjacent to the M30A/M31A corridor and is between the terminating stations of the line Project, Merrivale TS and Hawthorne TS. The lease agreement and the yard setup, facility rentals, are forecast to cost an additional $2.2M.

- **OPGW Installation and associated facility removals** ($1.6M) – The OPGW installation project plan for the M31A circuit and associated cost estimate, did not include an additional trenching required for the fiber routes from the transmission towers to the control buildings. The cost of equipment rental needed for the trenching and removals is estimated to be $0.8M, and the associated additional costs for labour (including project management), subcontractor costs and materials is forecast to be $0.8M, totaling and additional $1.6M.

- **Other** – The balance of the cost increase, approximately $6.9M, is due to several items, consisting of i) additional interest and overhead, the majority related to the specific cost elements outlined above, ii) increases in labour rates during project execution period, compared to estimated, and iii) the increase in the cost of constructing and removing access roads for the Project.

Sincerely,

Joanne Richardson

c/ Intervenors of record in EB-2020-0265 (electronic only)

APPENDIX A – ECONOMIC RATE IMPACT ANALAYSIS

For comparison purposes, Hydro One updated the 2020 analysis underpinning its S.92 Application evidence utilizing the updated Project cost estimate included in this letter. The results of the analysis, as it related to the impact on those customer bills, is provided below in Table 1.

Table 1
Rate Impact Using the S.92 Average Residential Consumption as per Prefiled Evidence (920 kWh[4])

Rate Impact Year of Comparison	**2020 Rate Impact**	
Cost Estimate Utilized	**2020 Estimate as Filed in S.92**	**2022 Updated Cost Estimate**
A. Typical monthly bill	$181.58 per month	
B. Transmission component of monthly bill	$15.31 per month	
C. Line Connection Pool share of Transmission component	$2.11 per month	
D. Transformation Connection Pool share of Transmission component	$5.07 per month	
E. Network Connection Pool share of Transmission component	$8.13 per month	
F. Impact on Network Connection Pool Provincial Uniform Rates	0.26%	0.51%
G. Increase in Transmission costs for typical monthly bill (C x D)	$0.02 per month or $0.25 per year	$0.04 per month or $0.5 per year
H. Net increase on typical residential customer bill (E / A)	0.01%	0.02%

*Items A to E are based on Typical monthly bill prior to analysis the impact of the Project's cost on rates.

Additionally, Hydro One is providing an analysis of the cost increase included in this letter using the OEB-assumed 2023 average residential consumption, of 750 kWh. The results of the analysis, as it related to the impact on those customer bills, is provided below in Table 2.

[4] This Average Residential Consumption represents the OEB's 2020 assumed amount.

Table 2

Rate Impact Using Current Average Residential Consumption (750 kWh[5])

Rate Impact Year of Comparison	**2023 Rate Impact**	
Cost Estimate Utilized	**2020 Estimate as Filed in S.92**	**2022 Updated Cost Estimate**
A. Typical monthly bill	$134.52 per month	
B. Transmission component of monthly bill	$15.98 per month	
C. Line Connection Pool share of Transmission component	$1.55 per month	
D. Transformation Connection Pool share of Transmission component	$5.23 per month	
E. Network Connection Pool share of Transmission component	$9.20 per month	
F. Impact on Network Connection Pool Provincial Uniform Rates	0.00%	0.18%
G. Increase in Transmission costs for typical monthly bill (C x D)	$0.00 per month or $0.00 per year	$0.02 per month or $0.2 per year
H. Net increase on typical residential customer bill (E / A)	0.00%	0.01%

* Items A to E are based on Typical monthly bill prior to analysis the impact of the Project's cost on rates.

[5] This Average Residential Consumption represents the OEB's 2023 assumed amount.

Hydro One Networks Inc.
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BY EMAIL AND RESS

November 28, 2024

Mr. Musab Qureshi
Manager of Generation & Transmission
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Qureshi,

EB-2020-0265 – Hydro One Networks Inc. Section 92 – Hawthorne to Merivale Reconductoring Project – Notification of Project Completion and Update on Project Cost

In accordance with the Ontario Energy Board's ("OEB") Decision and Order regarding Hydro One's leave to construct application for the Hawthorne to Merivale Reconductoring Project ("HMR Project" or "Project"), dated April 22, 2021, Hydro One is pleased to inform the OEB of the Project's completion and provide an update on a reduction in forecast Project costs.

The HMR Project was successfully completed and placed in service on July 1, 2023, approximately five months ahead of the anticipated completion date of December 2023, provided in Hydro One's leave to construct application (December 2023).

In a letter dated January 18, 2023 (the "2023 Letter"), Hydro One notified the OEB of an expected increase in the Project's cost from the approved $21.3 million to $46.9 million (inclusive of removals). The 2023 Letter detailed drivers behind the revised Project forecast cost.

We are now pleased to report a cost reduction of approximately **$8.0 million** from the 2023 Letter's estimate, resulting in a final Project cost of **$38.9 million**. This reduction is primarily due to efficiencies gained during the stringing of conductors on the second circuit (M30A). The outage duration for construction on circuit M30A was significantly shortened compared to the forecast in the 2023 Letter, thanks to lessons learned from the execution of the first circuit restringing (M31A) and advantageous circuit-outage availability durations.

Cost Reduction Breakdown

1. **Direct Cost Savings:**
   - The re-stringing of the conductors on circuit M30A resulted in direct cost savings of $1.6 million, attributable to a reduction in Project Management, labour and rental equipment cost. The forecast included in the 2023 Letter had anticipated a completion date of December 2023 and higher costs due to complexities encountered during the M31A re-stringing, which pertained to the dual-bundled conductor circuit configuration and logistical challenges near major infrastructure.

2. **Lower Overhead and Interest Costs:**
   - The overall reduction in direct Project costs and a shorter construction timeframe led to an additional $6.4 million in savings. The original cost estimate was based on an Advancement of Cost Engineering Class 2 estimate, which included indirect costs that assumed a December 2023 completion date. Having completed the Project five months early not only reduced direct costs but also lowered interest and overhead expenses.

3. **Impact on Customer Bills**
   The updated Project cost of **$38.9 million** will result in a modest increase of **$0.04** per month for a typical 2020 residential customer, bringing their monthly bill to **$181.62** based on the OEB's average consumption assumptions at the time the s.92 application was filed. For 2024, the impact on a typical customer bill, based on an average consumption of **750 kWh**, will be an increase of **$0.03** per month, totaling **$153.25**. Further details are provided in Tables 1 and 2 of Appendix A (attached).

Sincerely,

Joanne Richardson

c/ Intervenors of record in EB-2020-0265 (electronic only)
c/ OEB Registrar

APPENDIX A – ECONOMIC RATE IMPACT ANALAYSIS

For comparison purposes, Hydro One updated the 2020 analysis underpinning its S.92 Application evidence utilizing the updated Project cost estimate included in this letter. The results of the analysis, as it related to the impact on those customer bills is provided below in Table 1.

Table 1 - Rate Impact Using the S.92 Average Residential Consumption as per Prefiled Evidence (920 kWh[1])

Rate Impact Year of Comparison	2020 Rate Impact	
Cost Estimate Utilized	**2020 Estimate as Filed in S.92**	**2024 Updated Cost Estimate**
A. Typical monthly bill	$181.58 per month	
B. Transmission component of monthly bill	$15.31 per month	
C. Line Connection Pool share of Transmission component	$2.11 per month	
D. Transformation Connection Pool share of Transmission component	$5.07 per month	
E. Network Connection Pool share of Transmission component	$8.13 per month	
F. Impact on Network Connection Pool Provincial Uniform Rates	0.26%	0.51%
G. Increase in Transmission costs for typical monthly bill (C x D)	$0.02 per month or $0.25 per year	$0.04 per month or $0.5 per year
H. Net increase on typical residential customer bill (E / A)	0.01%	0.02%

*Items A to E are based on Typical monthly bill prior to analysis the impact of the Project's cost on rates.

[1] This Average Residential Consumption represents the OEB's 2020 assumed amount.

Additionally, Hydro One is providing an analysis of the cost increase included in this letter using the OEB-assumed 2024 average residential consumption, of 750 kWh. The results of the analysis, as it related to the impact on those customer bills is provided below in Table 2.

Table 2 - Rate Impact Using Current Average Residential Consumption (750 kWh[2])

Rate Impact Year of Comparison	**2024 Rate Impact**	
Cost Estimate Utilized	**2020 Estimate as Filed in S.92**	**2024 Updated Cost Estimate**
A. Typical monthly bill	$153.22 per month	
B. Transmission component of monthly bill	$17.11 per month	
C. Line Connection Pool share of Transmission component	$1.6 per month	
D. Transformation Connection Pool share of Transmission component	$5.42 per month	
E. Network Connection Pool share of Transmission component	$10.09 per month	
F. Impact on Network Connection Pool Provincial Uniform Rates	0.16%	0.33%
G. Increase in Transmission costs for typical monthly bill (C x D)	$0.02 per month or $0.2 per year	$0.03 per month or $0.4 per year
H. Net increase on typical residential customer bill (E / A)	0.01%	0.02%

* Items A to E are based on Typical monthly bill prior to analysis the impact of the Project's cost on rates.

[2] This Average Residential Consumption represents the OEB's 2024 assumed amount.

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BY EMAIL AND RESS

June 3, 2024

Mr. Musab Qureshi
Manager - Generation & Transmission
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Qureshi,

EB-2021-0136 – Hydro One Networks Inc. Section 92 – Richview to Trafalgar Reconductoring Project - Update on Project Cost

In accordance with the Ontario Energy Board's ("OEB") Decision and Order and Condition of Approval #3 regarding Hydro One's leave to construct application for the Richview to Trafalgar Reconductoring Project ("RxT Project" or "Project"), dated December 2, 2021, Hydro One is providing the OEB with an update regarding an increase in the Project's cost. The Project in-service date is not expected to change from that approved in Hydro One's s.92 Application, namely April 2026. Hydro One's revised Project forecast cost total is $92.8M versus $60.9M, as approved in EB-2021-0163

The updated Project cost estimate of $92.8M was derived from applying the Association for Advancement of Cost Engineering (AACE) Class 3 estimate (+30% / -20%) principles and processes. The Project is approximately 55% complete resulting in the elimination of some of the execution risks that were considered and included in the Project's s.92 Application cost estimate, done prior to construction commencement. Major risks that are now eliminated include: the completion of Project designs of the four circuit upgrades (i.e. R14T, R17T, R19TH and, R21TH) and OPGW installation atop the towers carrying circuits R14T and R17T, and the procurement of all Project materials.

The RxT Project remains the preferred alternative, consistent with the options considered and analysis provided in Hydro One's s.92 Application at Exhibit B, Tab 5, Schedule 1. The RxT Project will provide benefits consistent with the evidence provided to the OEB in the S.92 leave to construct hearing, that being increased capacity and reliability along this critical major transmission corridor. During Project development and construction execution Hydro One has and will continue to maintain regular communication with the IESO regarding Project updates, including forecast cost and in-service timing. The IESO continues to support the Project as the preferred option to meet the required 2026 need date and maintain the circuit's reliability standards.

Based on the updated Project cost forecast a typical residential customer's 2024 monthly bill, based on the OEB-approved average residential consumption of 750 kWh, would increase $0.03 per month to $150.79[1]

[1] Appendix A, Table 2, Row A, Average monthly bill amount of $150.76, plus, the $0.03 increase resulting from the updated Project forecast costs = $150.79 per month.

versus $0.02 per month shown in the s.92 application. Details of the economic impact comparative information for 2024 and 2021 respectively (the period of analysis applicable when the application was filed), are provided below in **Tables 1** and **2** of **Appendix A.**

Variance Explanation

The increase in Project cost, compared to the OEB-approved level is mainly attributable to changes in, 1) Project definition assumptions ($22.1M), 2) hardware product development and installation challenges ($4.5M), and 3) additional contingency, overhead, and interest ($5.3M).

1. Changes in Project Definition Assumptions - $22.1M

Conductor Installation Challenges: This Project is utilizing the Aluminium Conductor Steel Supported (ACSS)-type conductor. The ACSS conductor has not historically been widely used by Hydro One, however, it was selected for this Project because of the need to meet the circuit's ampacity requirements without replacing the existing towers, which would otherwise have been required for a comparatively heavier Aluminium Conductor Steel Reinforced ("ACSR") conductor that would also have the required Project ampacity rating. The smaller ACSS diameter conductor is lighter weight which will negate the need to replace the existing towers entirely, saving considerable structure replacement cost. Other advantages of the ACSS compared to standard ACSR conductors include its ability to operate at elevated temperatures and has excellent self-damping properties. Utilizing the ACSS conductor maximized the ability to utilize the existing infrastructure without costly and operationally prohibitive tower replacements.

Due to the limited use of ACSS conductors on Hydro One's system, during Project execution it was discovered that initial benchmarks for installation were under-estimated due to larger and comparatively more expensive hardware than assumed and to the increase in installation labour for splicing requirements associated with ACSS. To support the additional installation effort, maintain the original schedule commitments to the IESO, and manage labour market conditions causing limited availability of experienced skilled trades in Ontario for transmission lines construction work, significantly higher construction costs are included in the updated Project forecast. This has resulted in an **$8.3M** increase to the Project's cost.

Labour and Equipment Rate Refresh compared to the s.92 Estimate: Following the completion of the Project definition and AACE Class 3 estimate, the labour and equipment rates, as included in the leave to construct application were refreshed, resulting in an increase of **$2.3M**. This increase only reflects the rates used to estimate labour and equipment hours. It does not include incremental increases in labour effort, or equipment usage levels beyond the original forecast plan. Information related to incremental labour effort and equipment use required, beyond the original forecast, is described below, and in the details regarding Conductor Installations Challenges, above.

Commodity and Hardware Procurement Costs: Higher procurement costs of **$3.0M** are directly tied to the volatility of the global supply chain and higher than anticipated inflation for raw commodity prices required for the Project, such as steel, aluminium, ACSS conductor, and other associated Project materials. These commodities have seen material cost increases post-OEB s.92 Project approval. Despite the supply chain

constraints, manufacturing capacity was secured early enough in the Project's execution phase, such that Hydro One does not expect a delay to the Project's in-service date.

Utility Infrastructure within the Transmission Corridor: The transmission corridor for this Project contains eight different pipelines owned by five different companies, including vital gas mains regulated by the Canadian Energy Regulator. The alignment of the gas pipeline was known during the Project planning phase and temporary access routes, crossing locations and required permits were considered, consistent with Hydro One's prior comparable projects. However, permit requirements specific to this Project, pertaining to other parameters such as, age, condition, depth of the pipeline/s, and the pipe design capacity, were unknown until specific permits were sought and acquired by Hydro One, prior to Project construction. The detailed temporary access and protection measures requirements for existing third-party assets are not typically captured in the design package completed prior to construction execution. After having obtained clarifications for the facilities that co-exist on the adjacent Right of Way, and after consultation and engagement with gas pipeline owners, Hydro One's application for permits/approvals, included the need for a more extensive and robust protection and safety measures - in multiple locations - in order to mitigate risk of damage to existing pipelines from the use of heavy construction equipment adjacent or overtop of the pipelines. These measures include air bridges, wooden mats, and steel plates and more than the single layer of aggregate atop the pipeline crossing locations that was originally budgeted. As a result, the Project's workplan augmentation and protective measures resulted in additional costs of **$2.2M**

Urban Project Complexity: The Project's transmission corridor spans within urban areas, including multiple road crossings, pedestrian trails, and distribution feeder crossings. The work plan developed during the Project definition phase accounted for many anticipated urban complexities of the work specific to this corridor, however, the actual level of effort required to navigate the multitude of urban execution areas was underestimated. Municipal and Provincial authorities only granted permission for overnight highways and major roadway closures. This resulted in unplanned labour increases due to overtime-premium rates combined with additional Ministry of Transportation construction methodology requirements for installation of additional guiderails at highway crossings for public safety and accident prevention prior to the work commencing. These measures, consistent with Hydro One's safety procedures and industry best-practices, are required for the safe and efficient stringing of conductors across provincial highways, municipal roadways, park trails, transit stations, and waterbodies. During Project execution in the highly urbanized areas, the access challenges required specialized vehicle hire, including the use of cranes with modified boom tips and more rider poles designed to maintain public safety around road crossings. Also, cover-ups[2] on low voltage lines to eliminate areas of potential contact with low voltage lines during conductor stringing operations, were necessary. These unforeseen measures increased Project costs by **$3.1M** more than originally estimated.

[2] Refers to the construction measure to protect live low voltage distribution circuits beneath the transmission circuit project.

Additional Tower Structure Requirements: The use of the ACSS conductor, as discussed above, negated the need to replace towers in their entirely, however certain individual steel components of each tower still required modifications due to the larger sized conductor. Although the estimate underpinning the s.92 Application included upgrades to the towers to a higher security class (i.e. stronger load baring capability), the size and volume of steel members were underestimated, as were the on-site drilling work-methods for the installation of the new steel members. The incremental costs for the steel and labour effort for these reinforcements is **$2.1M**.

Construction Yard: The siting and operating costs of the Project's construction yard ("Yard") were impacted by a suitability assessment – prior to Project execution – regarding the adequacy of the planned construction setup, laydown and materials storage yard. The original cost estimate assumed the Yard adjacent to Tomken TS would be used, however, that location proved inadequate due to the interference from nearby low voltage distribution lines, oil and natural gas pipelines, as well as additional permitting requirements from the Toronto Region Conservation Authority. The Yard Hydro One ultimately selected was set up at the Erin Mills Athletic Fields, a location further west of Tomken TS due to better suitability i.e. resolving challenges to the prior planning location and having additional space and improved accessibility. However, this Yard site lacked nearby electrical supply, requiring a portable diesel generator to be brought to the Yard site. Generator rental and fuel costs were not accounted for in the original cost estimate. Additionally, a security monitoring system was installed for the facilities that was also not previously budgeted for. The additional costs to revise the Yard site and operate the construction Yard have resulted in an additional **$1.1M**.

2. Hardware Development, and Installation Challenges - $4.5M

Hardware Development: Connectors for ACSS conductors that could meet Hydro One's thermal-mechanical requirements and the newly updated American National Standards Institute specifications were not readily available commercially. For this reason, new components were designed and tested by a third party, resulting in an initial six-month delay to the start of the conductor installation. The additional testing and development costs, the additional time for construction personnel to be trained and become familiar with the installation procedure of the new hardware, and the overtime effort to recover lost time and maintain the in-service date resulted in an additional **$4.5M** of costs to the Project.

3. Contingency, Interest, and Overhead – $5.3M

The Project cost variance includes additional contingency of **$3.5M** (which represents 8.1% of the remaining $43.0M of forecast gross costs remaining), additional forecast overhead of **$1.3M**, and additional forecast interest of **$0.5M**. The contingency amount increases are a result of having conducted a refreshed risk workshop and a probabilistic assessment to quantify known risks, consistent with the current process.

This Project is eligible for, and meets the criteria of, Hydro One's OEB-approved Externally Driven Work Account, whereby Hydro One will record, once placed in-service, any revenue requirement incremental

beyond amounts embedded in the 2023-27 Joint Rate Application[3], until the next opportunity to have this Project's total in-service additions included in its rate base.

Sincerely,

Joanne Richardson

c/ Intervenors of record in EB-2021-0136 (electronic only)

[3] EB-2021-0110.

APPENDIX A – ECONOMIC RATE IMPACT ANALAYSIS

For comparison purposes, Hydro One updated the 2021 analysis underpinning its S.92 Application evidence utilizing the updated Project cost estimate included in this letter. The results of the analysis, as it related to the impact on those customer bills, is provided below in Table 1.

Table 1
Rate Impact Using the S.92 Average Residential Consumption as per Prefiled Evidence (700 kWh[4])

Rate Impact Year of Comparison	**2021 Rate Impact**	
Cost Estimate Utilized	**2021 Estimate as Filed in S.92**	**2024 Updated Cost Estimate**
A. Typical monthly bill	$148.68 per month	
B. Transmission component of monthly bill	$11.65 per month	
C. Line Connection Pool share of Transmission component	$1.61 per month	
D. Transformation Connection Pool share of Transmission component	$3.86 per month	
E. Network Connection Pool share of Transmission component	$6.19 per month	
F. Impact on Network Connection Pool Provincial Uniform Rates	0.51%	0.77%
G. Increase in Transmission costs for typical monthly bill (C x D)	$0.03 per month or $0.38 per year	$0.05 per month or $0.57 per year
H. Net increase on typical residential customer bill (E / A)	0.02%	0.03%

*Items A to E are based on Typical monthly bill prior to analysis the impact of the Project's cost on rates.

[4] This Average Residential Consumption represents the OEB's 2021 assumed amount.

Additionally, Hydro One is providing an analysis of the cost increase included in this letter using the OEB-assumed 2024 average residential consumption, of 750 kWh. The results of the analysis, as it related to the impact on those customer bills, is provided below in Table 2.

Table 2
Rate Impact Using Current Average Residential Consumption (750 kWh[5])

Rate Impact Year of Comparison	**2024 Rate Impact**	
Cost Estimate Utilized	**2021 Estimate as Filed in S.92**	**2024 Updated Cost Estimate**
A. Typical monthly bill	$150.76 per month	
B. Transmission component of monthly bill	$16.54 per month	
C. Line Connection Pool share of Transmission component	$1.60 per month	
D. Transformation Connection Pool share of Transmission component	$5.42 per month	
E. Network Connection Pool share of Transmission component	$9.52 per month	
F. Impact on Network Connection Pool Provincial Uniform Rates	0.17%	0.35%
G. Increase in Transmission costs for typical monthly bill (C x D)	$0.02 per month or $0.19 per year	$0.03 per month or $0.4 per year
H. Net increase on typical residential customer bill (E / A)	0.01%	0.02%

* Items A to E are based on Typical monthly bill prior to analysis the impact of the Project's cost on rates.

[5] As per OEB Report - Defining Ontario's Typical Electricity Residential Customer 2023 Update (EB-2023-0311)

TRANSMISSION CAPITAL PERFORMANCE REPORT – 2023

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Program Performance Report provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2023 in relation to the overall Transmission 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 at 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

Table 1 below presents a breakdown of the actual 2023 Transmission capital 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 Transmission System Access, System Renewal, and System Service categories. The Transmission 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 Transmission 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	$83.6	$61.1	-$22.5	$75.7	$26.4	-$49.2
System Renewal	$1,103.4	$968.2	-$135.2	$1,093.8	$882.2	-$211.6
System Service	$95.6	$139.0	$43.4	$60.6	$228.8	$168.2
General Plant	$143.7	$146.3	$2.6	$160.1	$152.6	-$7.5
Productivity[4]	-$64.2			-$56.2		
Total	**$1,362.1**	**$1,314.6**	**-$47.5**	**$1,334.1**	**$1,290.1**	**-$44.0**

Overall, Hydro One's transmission capital expenditures for 2023 were 3% below the OEB-approved amount and ISA for 2023 were 3% below the OEB-approved amount. The decrease in Hydro One's transmission capital expenditures and ISAs was largely due to lower spending in the System Renewal and System Access category (i.e., customer driven) as described below. These decreases were partly offset by increases in the System Service category.

Notwithstanding lower expenditures at the envelope level, 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. The OEB categories and associated variance explanations are outlined below.

System Access: System Access capital expenditures were $22.5M below the OEB-approved amount. This variance was primarily driven by the Metrolinx Barrie Corridor Line Relocation project (T-SA-07) where through joint development work with Metrolinx, it was concluded that the contemplated on-corridor solution would not meet the technical and operational requirements of either Hydro One or Metrolinx. The parties have subsequently started to explore a solution to relocate the transmission lines outside of the Metrolinx rail corridor, on an extended timeline/schedule. System Access ISAs were $49.2M below the

[2] Does not include Hydro One affiliates.
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 (Table 22 and 23)
[4] Productivity is reflected in Actual expenditures.

OEB-approved amount. This variance is primarily driven by the Metrolinx Barrie Corridor Line Relocation project (T-SA-07) for the same reason noted above.

System Renewal: System Renewal capital expenditures were $135.2M below the OEB-approved amount. This variance was primarily driven by investment redirections across OEB categories to accommodate mandatory system growth investments that emerged and required system upgrades. This variance reflects lower than planned investments for line refurbishments and integrated station investments, and in particular D2/3H Transmission Line Refurbishment (T-SR-13) which was reprioritized, Murray TS: T14, (T13) & Component Replacement (T-SR-03) due to changes in the scope of work impacting project timing, Bruce B SS ABCB Replacement (T-SR-02) which was substantially completed in 2022, and Replace Legacy SONET Systems (T-SR-11) which was reprioritized as it required additional planning.

System Renewal ISAs were $211.6M below the OEB-approved amount. This variance is primarily driven by Bruce A 500kV ABCB Replacement (T-SR-02) where the project pacing was refined, Wilson TS: T1 & Component Replacement (T-SR-03) where the late delivery of materials impacted the project schedule, Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement (T-SR-03) which was deferred to reevaluate the project scope, and Replace Legacy SONET Systems (T-SR-11) which was reprioritized.

System Service: System Service expenditures were $43.4M above the OEB-approved amount. This variance was primarily driven by the Barrie Area Transmission Upgrade (T-SS-Other) as the cost and schedule were revised to account for customer-initiated delays, scope update, and cost pressures described above. System Service ISAs were $168.2M above the OEB-approved amount. This variance is primarily driven by Barrie Area Transmission Upgrade (T-SS-Other) as outlined above, and Lennox TS 500kV Shunt Reactors (T-SS-Other) due unexpected site conditions and outage constraints which affected the project schedule.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM LEVEL

Hydro One takes an integrated approach to portfolio management and manages to the overall capital envelope. The approach recognizes that changes at both the project and program levels will occur. Individual variances, be it an annual or project total level are to be expected given the magnitude and complexity of the work being performed. Each project involves a unique combination of elements related to the scope of work included and site conditions and is undertaken pursuant to a defined project delivery process with a range of expected outcomes as defined by the AACE class of estimate.[5] Projects are typically released for execution and funded based on a Class 3 estimate as further discussed below. As projects are executed, they are managed to allow Hydro One to be responsive to execution challenges and to update the project scope, where required, while continuing to deliver the projects according to Hydro One's project delivery process.

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in this report in reference to project total variances and overall project schedule variances. Programs are different in that the budget is set annually and are managed and governed against these budgets. As such, program performance is discussed in the context of adherence to annual budgets.

3.1 OVERVIEW

The projects and programs discussed in this report represent 96% 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.

Hydro One's project performance in relation to project total budgets for all projects with material (greater than or equal to $3M) actual or planned ISA in 2023 is presented in Figure 1 below. The blue vertical lines in the cost variance chart are placed at -20% and +30% which is the range of expected outcomes that most commonly aligns with an AACE Class 3 estimate, and representative of the typical project definition work completed at the

[5] AACE estimate classification is discussed in EB-2021-0110, TSP Section 2.10.

time of business case approval at Hydro One. This figure shows a relatively tight dispersion of cost performance. This demonstrates Hydro One's overall effectiveness in executing projects within the range anticipated when the project budgets were established. This is particularly true for larger projects (>$30M) that are subject to increased rigour and scrutiny as part of the project delivery process. Use of a Class 3 estimate to establish the appropriate range for completed projects is reasonable as that is the basis on which the projects are generally funded, and it is consistent with industry usage of Class 3 criteria for budget authorization or control estimates.

As can be seen, the majority of projects (89% = 39 of 44) have project total variances that fall within the upper range of AACE Class 3 expected outcomes (+30% of nominal value). Examining the 5 projects that are forecast to exceed their project total budgets by more than 30%, one of the projects has a variance due to work definition issues, which arose as project details were refined, and four projects encountered unforeseen execution issues (i.e. unexpected site conditions, outage issues, material issues, etc.).

Similarly, Figure 2 below shows that the vast majority of projects (98% = 43 of 44) were completed / forecast to complete on plan, within 12 months of baseline. A one-year target range is reasonable given that Hydro One's primary outage availability is during the spring and fall due to system conditions and loading, which often leads to project schedule shifts.

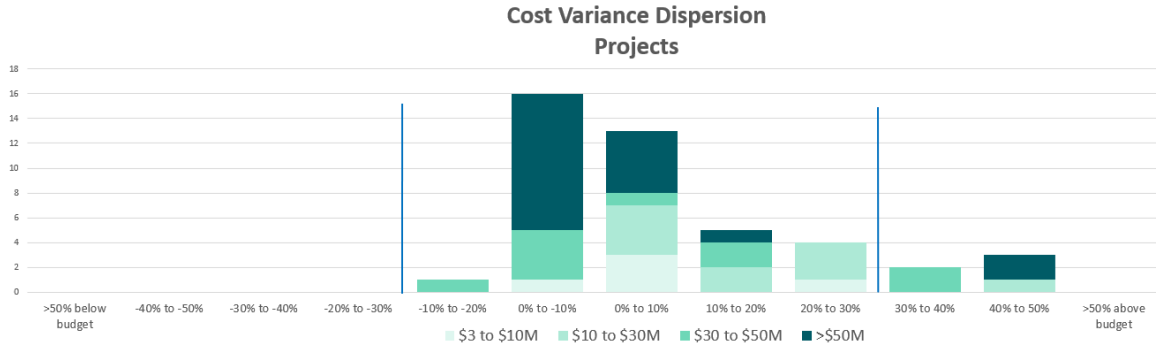

Figure 1: Cost Variance Dispersion for Projects with Planned or Actual ISA in 2023 of $3M or More[6]

[6] Based on actual cost for completed projects and forecast cost at completion for projects still in progress.

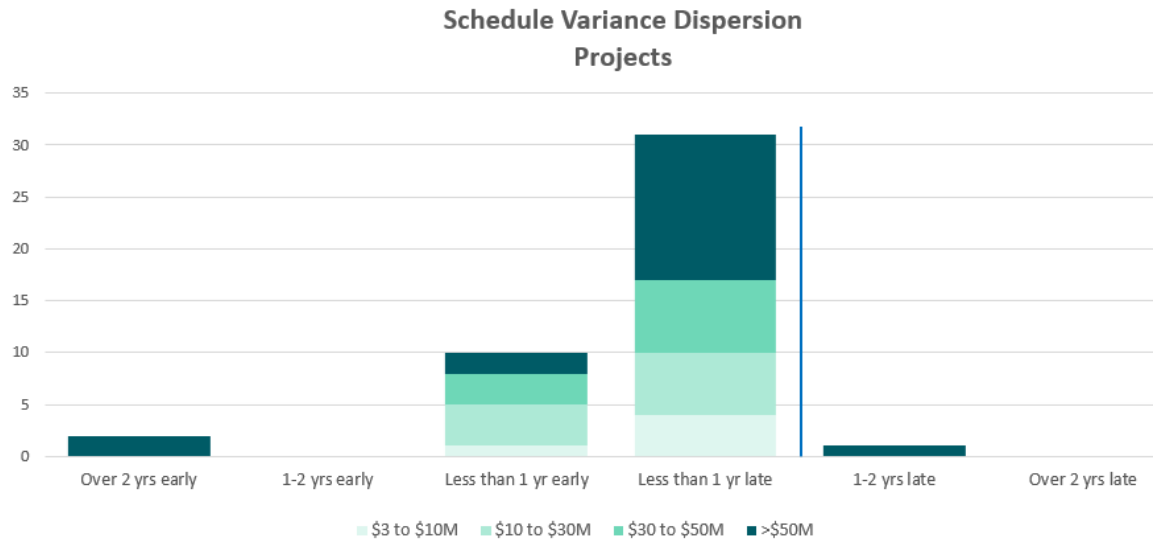

Figure 2: Schedule Variance Dispersion for Projects with Planned or Actual ISA in 2023 of $3M or More[7]

3.2 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2023 greater than or equal to $3M have been summarized in the tables below along with variance explanations. The thresholds used by Hydro One to identify "material variances" were determined using the following criteria[8]:

- **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** – 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

[7] Based on actual in-service date for completed projects and forecast in-service date for projects still in progress.
[8] 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.

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 or 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 materially changing the in-service amount or affecting the overall scope 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, the 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 to the project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

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 PROJECT PERFORMANCE

As summarized in Table 3 below, transmission projects are well managed with a focus on adherence to the overall project total budget and project schedule.

1

Table 3 - Transmission Project Summary

Project Characteristics			2023 Tx Capital Expenditures ($M)		2023 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[9]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
System Access													
Load Customer Connection													
IAMGOLD - 115 kV Mine Connection, T61S Line Refurbishment[10]	Complete	T-SA-02	17.3	9.9	27.3	22.2	53.7	49.0	-4.7	2023	2023	0	Not a material variance
System Renewal													
Integrated Station Investment													
Arnprior TS - Station Rebuild	Complete	T-SR-03	7.9	8.5	31.4	34.8	31.4	36.2	4.9	2023	2023	0	Work Definition
Beck #1 SS ABCB Replacement	Execution	T-SR-02	9.9	4.0	5.3	3.6	54.2	52.9	-1.3	2026	2026	0	Not a material variance
Beck #2 TS ABCB Replacement	Execution	T-SR-02	10.6	9.4	33.4	11.4	122.2	128.5	6.4	2023	2024	1	Execution Factors
Bridgman TS Load Station Transformer Replacement	Execution	T-SR-03	23.7	21.4	30.0	41.4	69.3	98.1	28.8	2024	2026	2	Execution Factors
Bruce B SS - ABCB Replacement	Complete	T-SR-02	5.2	4.7	10.0	10.1	182.3	181.1	-1.2	2024	2022	-2	Not a material variance
Cecil TS: T1 & Component Replacement	Complete	T-SR-03	4.1	1.8	7.4	0.1	18.5	18.8	0.3	2023	2023	0	Not a material variance
Cherrywood TS 230kV ABCB Replacement	Complete	T-SR-02	8.4	6.1	13.0	6.4	97.9	93.2	-4.7	2023	2023	0	Not a material variance
Cherrywood TS 500kV ABCB Replacement (Phase 3-1)	Execution	T-SR-02	17.2	11.8	18.2	20.8	74.8	71.9	-2.9	2025	2025	0	Not a material variance
Claireville TS: Component Replacement	Execution	T-SR-01	5.5	7.5	2.0	12.9	27.9	33.8	5.9	2025	2025	0	Execution Factors
Fairbank TS: T1, T2, T3, T4, PCT & LV Yard Replacement	Execution	T-SR-03	11.7	13.3	0.1	22.6	70.6	79.3	8.8	2024	2024	0	Execution Factors
Gage TS: T3,T4,T5,T6, PCT & Switchyard Reconfiguration	Execution	T-SR-03	18.6	14.9	41.4	30.9	84.2	80.5	-3.7	2023	2024	1	Execution Factors
Hawthorne TS ISCR	Execution	T-SR-03	1.9	1.1	3.7	3.4	44.6	43.2	-1.4	2024	2024	0	Not a material variance

[9] Phases: Planning, Execution, or Complete.
[10] IAMGOLD - 115 kV Mine Connection and T61S Line Refurbishment have been merged in this report as they are being executed as a single project.

Project Characteristics			2023 Tx Capital Expenditures ($M)		2023 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[9]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
Keith TS: T11, T12 & Component Replacement	Complete	T-SR-01	9.1	11.1	29.1	19.6	42.0	48.7	6.7	2023	2023	0	Emergent Needs
Kenilworth TS: T1, T3, T4 & Switchyard Refurbishment	Complete	T-SR-03	7.9	5.2	8.5	5.3	49.6	46.7	-2.8	2023	2023	0	Not a material variance
Lambton TS: T7/T8, T5/T6, DESN Replacement	Execution	T-SR-03	35.8	35.3	68.5	53.4	69.9	73.1	3.2	2023	2024	1	Work Definition
Lennox TS: ABCB Component Replacement	Execution	T-SR-02	8.2	13.7	16.5	32.6	143.2	145.8	2.6	2026	2026	0	Not a material variance
Lincoln Heights TS: T1/T2 & Component Replacement	Execution	T-SR-03	8.1	8.0	12.0	11.7	20.2	23.8	3.6	2024	2024	0	Execution Factors
Middleport ABCB Replacement Project	Execution	T-SR-02	26.6	22.2	36.5	36.1	178.1	169.9	-8.2	2025	2025	0	Not a material variance
Milton SS: Component Replacement	Execution	T-SR-01	11.8	13.1	13.6	15.1	20.0	25.7	5.8	2024	2025	1	Execution Factors
Nanticoke TS: T11 & Component Replacement	Complete	T-SR-Other	1.0	1.0	12.2	1.0	18.2	18.4	0.2	2023	2022	-1	Not a material variance
Nanticoke TS: ABCB Replacement	Execution	T-SR-02	16.0	8.7	42.1	38.0	79.0	81.7	2.8	2026	2026	0	Not a material variance
Orangeville TS: Load Station Transformer Replacement	Execution	T-SR-03	4.7	10.5	8.0	9.3	35.6	46.3	10.7	2023	2024	1	Execution Factors
Parry Sound TS: Component Replacement	Complete	T-SR-03	7.2	6.1	12.5	12.3	22.8	23.8	1.0	2023	2023	0	Not a material variance
Pine Portage SS: Component Replacement	Execution	T-SR-01	7.2	4.8	0.0	11.2	38.4	36.8	-1.6	2024	2024	0	Not a material variance
Port Colborne TS: T61, T62 & Switchyard Refurbishment	Complete	T-SR-03	3.1	3.1	3.1	3.1	30.3	31.6	1.3	2022	2022	0	Not a material variance
Rabbit Lake SS: Component Replacement	Execution	T-SR-01	6.7	8.3	8.5	19.0	29.3	35.2	5.9	2024	2024	0	Work Definition
Slater TS T2/T3 & Component Replacement	Execution	T-SR-03	15.5	7.1	23.0	13.3	28.3	32.3	4.0	2024	2024	0	Execution Factors
Spruce Falls TS: Component Replacement	Complete	T-SR-03	2.4	3.9	5.2	6.7	5.5	6.7	1.2	2023	2023	0	Work Definition
Strachan TS T12/T14; A5-A6 M/C & Component Replacement	Complete	T-SR-Other	1.3	1.7	3.9	3.8	3.9	4.0	0.1	2023	2023	0	Not a material variance
Thorold TS: T1, MV Switchyard & Component Replacement	Execution	T-SR-03	6.3	11.9	28.7	32.7	31.8	41.4	9.6	2024	2024	0	Work Definition

Project Characteristics			2023 Tx Capital Expenditures ($M)		2023 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[9]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
Wingham TS: T1, T2, PCT & Component Replacement	Execution	T-SR-03	5.6	13.3	10.0	16.4	23.0	33.5	10.5	2024	2024	0	Execution Factors
Overhead Lines Refurbishment Projects, Component Replacement Programs													
A7L/R1LB/A6P & 57M1 Transmission Line Refurbishment	Complete	T-SR-Other	0.0	3.7	0.0	4.0	85.5	85.2	-0.3	2022	2022	0	Not a material variance
A8/9K Transmission Line Refurbishment	Complete	T-SR-13	14.9	22.6	38.5	38.7	69.5	73.2	3.7	2023	2023	0	Not a material variance
D1A/D3A Transmission Line Refurbishment	Complete	T-SR-Other	2.6	2.2	6.2	6.1	6.2	6.5	0.3	2023	2023	0	Not a material variance
Q3M6 Transmission Line Refurbishment	Execution	T-SR-13	1.1	0.7	3.3	0.0	3.6	3.8	0.2	2024	2024	0	Not a material variance
Protection and Automation													
Telecom Performance - Ring 6/2 (ADSS D6V/E9V)	Complete	T-SR-12	1.3	0.4	4.1	4.8	9.8	9.7	-0.1	2023	2023	0	Not a material variance
System Service													
Inter Area Network Capability													
East-West Tie Connection	Complete	T-SS-Other	7.4	5.1	21.9	21.3	189.0	187.8	-1.2	2024	2022	-2	Not a material variance
Lennox TS 500kV Shunt Reactors	Complete	T-SS-Other	4.8	5.4	33.1	33.8	55.0	54.1	-0.9	2023	2023	0	Not a material variance
M30A/M31A Conductor Upgrade	Complete	T-SS-03	18.8	13.8	19.3	15.5	43.7	38.6	-5.1	2023	2023	0	Not a material variance
St. Lawrence: PS33/PS34 Replacement and Upgrade	Complete	T-SS-02	5.0	4.4	15.6	14.1	33.6	32.7	-0.9	2023	2023	0	Not a material variance
Local Area Supply Adequacy													
Barrie Area Transmission Upgrade	Complete	T-SS-Other	29.7	27.5	84.5	85.7	105.1	100.2	-4.9	2023	2023	0	Not a material variance
Kapuskasing Area Reinforcement - Kapuskasing TS	Complete	T-SS-Other	0.6	0.7	22.9	23.4	22.9	23.7	0.8	2023	2023	0	Not a material variance
Richview x Trafalgar 230kV Conductor Upgrade	Execution	T-SS-04	18.0	24.4	22.0	30.2	59.3	85.4	26.1	2026	2026	0	Execution Factors

1

In terms of the larger project total variances, the **Bridgman TS Load Station Transformer Replacement (T-SR-03)** project is forecasted to exceed its total budget by $28.8M resulting from changes in the contingency tie cable route, estimating assumptions, constructability challenges, and LDC cost escalations. **The Richview x Trafalgar 230kV Conductor Upgrade (SS-04)** is forecasted to exceed its total budget by $26.1M primarily attributable to changes in project definition assumptions, and challenges from new hardware installation. The **Orangeville TS: Load Station Transformer Replacement (SR-03)** is forecasted to exceed its project total budget by $10.7M due to design modifications, scope changes, price increases due to global market conditions and defective materials.

In terms of projects that have had material schedule variances (i.e. delays from 2023 or earlier, to a later year), **the Orangeville TS: Load Station Transformer Replacement (T-SR-03)** project had a delay from 2023 to 2024 due to a delay in material being received and scope additions. The **Gage TS: T3,T4,T5,T6, PCT & Switchyard Reconfiguration (T-SR-03)** project had a delay from 2023 to 2024 due to execution factors from a failed transformer which required project modifications in collaboration with the customer to install a replacement transformer. **The Lambton TS: T7/T8, T5/T6, DESN Replacement (T-SR-03)** project's schedule delay from 2023 to 2024 is mainly attributable to increased time spent on work definition activities. Lastly, the **Beck 2 TS, ABCB Replacement & Yard Upgrade (T-SR-02)** project had a delay from 2023 to 2024 due to outage delays.

5.0 PROGRAM PERFORMANCE

Overall, the aggregate capital expenditure and ISA amounts for System Renewal programs in Table 4 below were above the overall Forecast amounts (+$13.6M and +$26.0M respectively).

1

Table 4 - Transmission Program Summary

Program Characteristics		2023 Tx Capital Expenditures ($M)			2023 Tx In-Service Additions ($M)			2023 Tx Units				Performance
Program Description	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Unit Description**	**Forecast**	**Actual**	**Variance**	**Variance Category**
System Renewal												
Steel Structure Coating Program	T-SR-05	19.0	12.7	-6.3	19.6	14.2	-5.4	# of Structures	455	297	-158	Reprioritization
Transmission Line Emergency Restoration	T-SR-15	10.6	8.2	-2.4	8.8	8.3	-0.5	# of work orders	115	96	-19	Not a material variance
Wood Pole Structure Replacement	T-SR-04	54.7	72.8	18.1	52.9	67.8	14.9	# of Structures	932	836	-96	Execution Factors
Transmission Line Insulator Replacement	T-SR-08	77.9	68.9	-9.0	72.7	70.0	-2.7	# of Circuit Structures	3,708	3,710	2	Not a material variance
Tx Lines Foundation Assess/Clean/Coat & Life Extension	T-SR-06	11.3	15.9	4.6	11.9	15.8	3.8	# of Structures	739	753	14	Execution Factors
Transmission Line Virtual Asset Inspection	T-SR-Other	3.0	3.0	0.0	5.3	0.0	-5.3	# of Circuit Structures	2,210	-	-2,210	Reprioritization
Transmission Line Shieldwire Replacement	T-SR-07	12.5	15.2	2.7	14.9	16.5	1.6	# of km	293	196	-97	Work Definition
Protection Relay Replacement Program	T-SR-10	9.1	5.1	-4.0	3.7	0.5	-3.3	# of Upgrades	40	1	-39	Reprioritization
Online DGA Monitor Program	T-SR-Other	3.0	3.8	0.7	3.8	3.6	-0.2	# of Installations	13	16	3	Reprioritization
Nuisance Wildlife Control	T-SR-Other	1.0	3.4	2.4	0.7	4.1	3.4	# of Orders	10	9	-1	Execution Factors
Transmission Station Demand, Spares and Targeted Assets	T-SR-09	43.4	50.2	6.8	32.3	52.0	19.7	n/a	n/a	n/a	n/a	Execution Factors

2

As noted in Section 2 above, overall System Renewal programs expenditures were reduced to offset increases in other non-discretionary categories. Specific programs are discussed as follows:

The **Wood Pole Structure Replacement (T-SR-04)** program had higher expenditures but was slightly under-accomplished due to wood pole shortages which necessitated the use of composite poles. Composite poles are more costly than wood poles and were the main factor in the increased expenditures.

The **Transmission Lines Insulator Replacement (T-SR-08)** program had lower expenditures but Hydro One was able to complete all budgeted units. The lower expenditures were due to the replacement of more 115kV and 230kV insulators on consecutive structures, leading to lower access and setup costs, and the cancellation of higher cost 500kV work due to outage constraints. Outage cancellations and shorter outage durations hampered execution efforts however work was reprioritized to achieve the budgeted units.

The **Steel Structure Coating (T-SR-05)** program had lower expenditures and unit accomplishments due to redirection to the Wood Pole Structure Replacement (T-SR-04) program to offset higher costs related to the use of composite poles. Notwithstanding the lower overall expenditures in this program, Hydro One completed a higher volume of double circuit work which is more costly.

Other programs that experienced material variances were:

- The **Tx Lines Foundation Assess/Clean/Coat & Life Extension (T-SR-06)** program had higher expenditures mainly due to the higher cost on 500kV structures and increased mobilization costs.
- The **Transmission Shieldwire Replacement (T-SR-07)** program had higher expenditures due to additional scope and outage cancellations.
- The **Protection Relay Replacement (T-SR-10)**, **Online DGA Monitor (T-SR-Other), and Transmission Lines Virtual Asset Inspection (T-SR-Other)** programs experienced portfolio reprioritization causing work to be shifted.
- The **Nuisance Wildlife Control (T-SR-Other)** program had higher expenditures due to increased complexity of wildlife barrier installations.

- The **Transmission Station Demand, Spares and Targeted Assets (T-SR-09)** program had increased costs due to an increase in demand replacements.

TRANSMISSION 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 transmission 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 at 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

Table 1 below presents a breakdown of the actual 2024 transmission capital expenditures and ISA by OEB investment category and compares them against OEB-approved values. The primary focus of this report is on the Transmission System Access, System Renewal, and System Service categories. The Transmission 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 Transmission 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	$74.6	$108.9	$34.3	$51.4	$47.9	-$3.5
System Renewal	$1,150.6	$1,182.2	$31.6	$1,105.6	$932.2	-$173.4
System Service	$107.0	$152.4	$45.4	$21.7	$93.8	$72.1
General Plant	$121.4	$126.7	$5.3	$149.6	$115.1	-$34.5
Productivity[4]	-$64.2			-$64.2		
Total	**$1,389.4**	**$1,570.3**	**$180.9**	**$1,264.2**	**$1,189.0**	**-$75.2**

In 2024, Hydro One's transmission capital expenditures for 2024 were 13% above the OEB-approved amount and ISAs were 6% below the OEB-approved amount. Transmission capital expenditures were higher largely due to increased spending in the System Service and System Access categories. Increased spending in System Service was primarily driven by mandatory transmission work required by governmental authorities (Externally Driven Work). The decrease in transmission ISAs was due to lower System Renewal additions. 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. The OEB categories and associated variance explanations are summarized below.

System Access: System Access capital expenditures were $34.3M above the OEB-approved amount. This variance was primarily driven by Centennial TS: Project Connect PowerCo (T-SA-New) which is mandatory for the connection of a customer facility, and by the Wallaceburg Transformer Station Conversion from 115 kV to 230 kV (T-SA-New). System Access ISAs were $3.5M below the OEB-approved amount. This variance was primarily driven by a customer delay to select a route for the Commerce TS New 230 kV Customer Connection project (T-SA-01).

[2] Does not include Hydro One affiliates or future Affiliate Transmission Lines Projects (ATP).
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 (Table 22 and 23)
[4] Productivity is reflected in Actual expenditures.

System Renewal: System Renewal capital expenditures were $31.6M above the OEB-approved amount. This variance was primarily driven by Bruce A 500kV - Replace ABCB & Yard Reconfiguration (T-SR-02) which was accelerated at the request of Bruce Power. System Renewal ISAs were $173.4M below the OEB-approved amount. This variance is primarily driven by Bruce A 500kV - Replace ABCB & Yard Reconfiguration (T-SR-02) where the timing of a partial ISA shifted through discussions with Bruce Power, the E1C Transmission Line Refurbishment project (T-SR-13) which was deferred due to outage constraints with the radial line requiring the project plan to be modified, and Lauzon T6, T5 & Component Replacement (T-SR-03) where the timing of a partial ISA shifted to 2025.

System Service: System Service expenditures were $45.4M above the OEB-approved amount. This variance was primarily driven by the addition of the Waasigan Transmission Line Project - Station Work (T-SS-Other-New) and by the Barrie Area Transmission Upgrade (T-SS-Other) due to customer-initiated delays and the completion of trailing work. System Service ISAs were $72.1M above the OEB-approved amount. This variance is primarily driven by Chatham SS x Lakeshore TS: Stations Work (T-SS-07) which was completed a year ahead of schedule, Sudbury Area Reinforcement - X25S Unbundling (T-SS-Other) due to a timing shift during project development, and Richview x Trafalgar 230kV Conductor Upgrade (T-SS-04) due to earlier partial in-servicing of the project.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM LEVEL

Hydro One takes an integrated approach to transmission portfolio management and manages to the overall capital envelope. The approach recognizes that changes at both the project and program levels will occur. Individual variances, be it an annual or project total level are to be expected given the magnitude and complexity of the work being performed. Each project involves a unique combination of elements related to the scope of work included and site conditions, and is undertaken pursuant to a defined project delivery process with a range of expected outcomes as defined by the Association for the Advancement of Cost Engineering (AACE) class of estimate.[5] Projects are typically released for execution and funded based on a Class 3 estimate. As projects are executed, they are managed to allow Hydro One to be responsive to execution challenges and

[5] AACE estimate classification is discussed in EB-2021-0110, TSP Section 2.10.

update project scope, where required, while continuing to deliver the projects according to Hydro One's project delivery process.

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in this report in reference to project total variances and overall project schedule variances. Programs are different in that the budget is set annually and are managed and governed against these budgets. As such, program performance is discussed in the context of adherence to annual budgets.

3.1 OVERVIEW

The projects and programs discussed in this report represent 96% 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.

Hydro One's performance in relation to material[6] projects with AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2), are presented in Figure 1 below.[7] The blue vertical lines in the cost variance chart are placed at -20% and +30% which is the range of expected outcomes that most commonly aligns with an AACE Class 3 estimate, and representative of the typical project definition work completed at the time of business case approval at Hydro One. The figure shows a relatively tight dispersion of cost performance with the majority of projects (69% = 27 of 39) having project variances below the AACE upper range, which is a reasonable result given the significant cost pressures experienced in recent years. The overall variance for the 39 projects is +10% which is well within the AACE Class 3 estimate range. Hydro One utilizes its Capital Project Delivery model to manage and remain effective in executing projects within the range anticipated when the project budgets were established. This is particularly true for

[6]Greater than or equal to $3M, and with actual or planned ISA in 2024
[7] This provides a more consistent evaluation of AACE Class 3-based project estimates against the AACE Class 3 estimate accuracy range.

larger projects (>$30M) that are subject to increased rigour and scrutiny as part of the project delivery process.

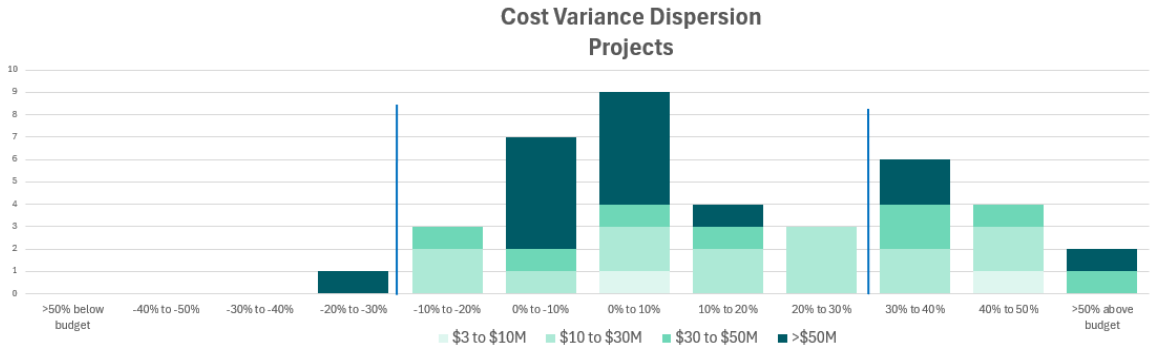

Figure 1: Material Projects' Cost Variance Dispersion[8]

Similarly, Figure 2 below shows that the majority of projects (79% = 31 of 39) were completed / forecast to complete on plan, within 12 months of baseline.

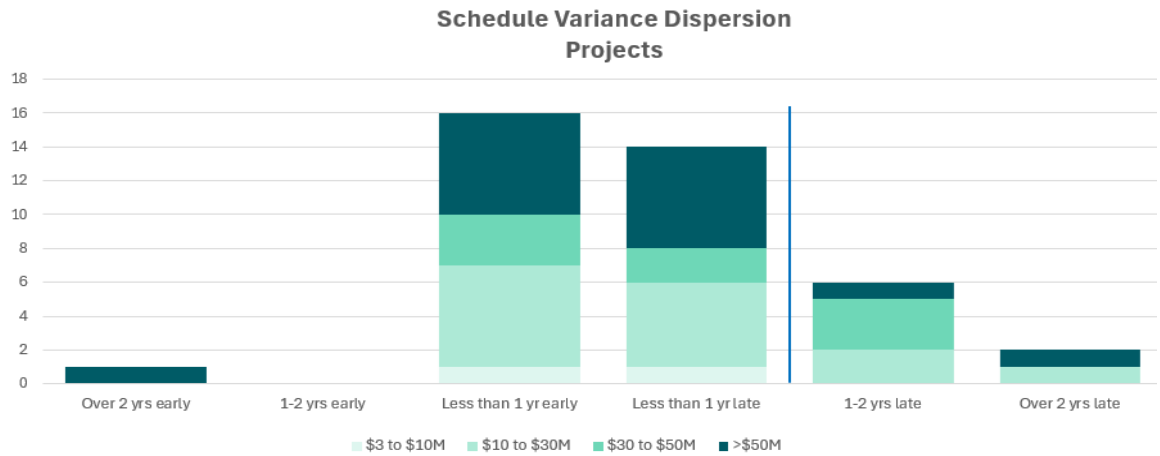

Figure 2: Material Projects' Schedule Variance Dispersion[9]

3.2 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2024 greater than or equal to $3M have been summarized in the tables below along with variance explanations. The

[8] Based on actual cost for completed projects and forecast cost at completion for projects still in progress.
[9] Based on actual in-service date for completed projects and forecast in-service date for projects still in progress.

thresholds used by Hydro One to identify "material variances" were determined using the following criteria[10]:

- **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** – 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 or 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 materially changing the in-service amount or affecting the overall scope 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

[10] 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.

Work definition variances arise from the process of refining a project's scope, the 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 to the project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

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 PROJECT PERFORMANCE

As summarized in Table 3 below, transmission projects are well managed with a focus on adherence to the overall project total budget and project schedule.

1

Table 3 - Transmission Project Summary

Project Characteristics			2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
System Access													
Oneida Battery Park	Complete	T-SA-Other	0.0	4.7	0.0	8.2	0.0	8.4	8.4	-	2024	n/a	Emergent Needs
Windsor NextStar TS: 230 kV/27.6 kV DESN	Complete	T-SA-Other	12.9	10.9	47.9	34.0	48.2	34.1	-14.1	2024	2024	0	Not Applicable
System Renewal													
Integrated Station Investment													
Beck 1 SS: ABCB Replacement	Execution	T-SR-02	8.5	4.4	3.4	4.3	54.2	40.8	-13.4	2026	2025	-1	Not Applicable
Beck 2 TS: ABCB Replacement	Complete	T-SR-02	0.0	8.1	0.0	29.4	122.2	127.1	4.9	2023	2024	1	Execution Factors
Bridgman TS Load Station Transformer Replacement	Execution	T-SR-03	9.0	16.7	21.9	30.2	69.3	95.4	26.1	2024	2026	2	Execution Factors
Bruce B SS: ABCB Replacement	Complete	T-SR-02	4.6	3.1	7.3	2.6	182.3	175.7	-6.6	2024	2022	-2	Not Applicable
Cecil TS: T1 & Component Replacement	Complete	T-SR-03	0.0	2.2	0.0	7.5	18.5	18.8	0.3	2023	2023	0	Not Applicable
Cherrywood TS: 500kV ABCB Replacement (Phase 3-1)	Execution	T-SR-02	11.0	14.1	19.5	18.8	74.8	72.5	-2.3	2025	2025	0	Not Applicable
Claireville TS: Component Replacement	Execution	T-SR-01	3.5	4.7	13.0	5.6	27.9	34.9	6.9	2025	2025	0	Execution Factors
Edgeware TS: PCT & Component Replacement	Complete	T-SR-03	0.8	1.8	13.2	14.2	13.2	14.2	1.0	2024	2024	0	Not Applicable
Fairbank TS: T1, T2, T3, T4, PCT & LV Yard Replacement	Complete	T-SR-03	6.0	10.2	31.2	16.1	70.6	79.7	9.2	2024	2024	0	Execution Factors
Gage TS: T3, T4, T5, T6, PCT & Switchyard Reconfiguration	Complete	T-SR-03	2.4	8.3	2.4	10.9	84.2	83.1	-1.1	2023	2024	1	Execution Factors
Glendale TS: Station Refurbishment and Reconfiguration	Planning	T-SR-03	8.5	1.2	11.5	0.0	52.9	19.1	-33.8	2027	2026	-1	Not Applicable
John TS: T5 and T6 Transformer Replacement	Execution	T-SR-03	10.6	13.2	10.1	0.0	25.9	29.1	3.2	2025	2025	0	Work Definition

[11] Phases: Planning, Execution, or Complete.

Project Characteristics			2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Keith TS: T11, T12 & Component Replacement	Complete	T-SR-01	0.0	5.7	0.0	7.7	42.0	49.3	7.3	2023	2023	0	Emergent Needs
Kirkland Lake TS: Component Replacement	Execution	T-SR-03	4.5	11.4	19.9	26.7	27.9	38.1	10.1	2025	2027	2	Execution Factors
Lake TS: T2 & Component Replacement	Complete	T-SR-03	8.6	8.1	9.0	11.0	39.9	11.1	-28.8	2026	2024	-2	Not Applicable
Lambton TS: T7/T8, T5/T6, DESN Replacement	Complete	T-SR-03	1.4	6.9	1.4	17.3	69.9	71.4	1.5	2023	2024	1	Work Definition
Lennox TS: ABCB Component Replacement	Execution	T-SR-02	8.1	11.1	16.5	23.0	143.2	153.9	10.7	2026	2026	0	Not Applicable
Lincoln Heights TS: T1/T2 & Component Replacement	Complete	T-SR-03	5.0	7.6	7.8	11.3	20.2	24.3	4.1	2024	2024	0	Execution Factors
Longwood TS: Component Replacement	Execution	T-SR-03	4.3	3.8	0.0	14.1	14.7	20.0	5.4	2025	2026	1	Work Definition
Mackenzie TS: Component Replacement – Phase 1	Execution	T-SR-01	21.5	30.0	18.9	0.0	47.3	61.8	14.5	2025	2025	0	Work Definition
Main TS: T3, T4 & Component Replacement	Execution	T-SR-03	9.6	9.5	45.5	0.0	48.0	70.4	22.4	2024	2025	1	Execution Factors
Marathon TS: Component Replacement	Planning	T-SR-01	10.5	0.7	11.7	0.0	30.7	35.0	4.4	2026	2027	1	Work Definition
Middleport TS: ABCB Replacement	Execution	T-SR-02	23.5	21.7	34.7	36.8	178.1	168.3	-9.8	2025	2025	0	Not Applicable
Middleport TS: T6 Replacement	Execution	T-SR-01	10.9	7.7	10.6	9.2	24.9	25.0	0.1	2025	2025	0	Not Applicable
Milton SS: Component Replacement	Execution	T-SR-01	3.2	6.1	6.2	6.7	20.0	28.4	8.4	2024	2025	1	Execution Factors:
Nanticoke TS: ABCB Replacement	Execution	T-SR-02	6.0	13.0	0.0	10.8	79.0	82.6	3.6	2026	2027	1	Not Applicable
Orangeville TS: Load Station Transformer Replacement	Complete	T-SR-03	2.2	6.7	11.1	21.6	35.6	47.3	11.7	2023	2024	1	Execution Factors
Otto Holden TS: T3/T4 & Component Replacement	Execution	T-SR-01	11.0	25.4	10.1	0.0	68.7	107.5	38.8	2027	2028	1	Work Definition
Pine Portage SS: Component Replacement	Complete	T-SR-01	3.6	2.7	23.9	4.0	38.4	34.3	-4.1	2024	2024	0	Not Applicable
Porcupine TS: Component Replacement	Execution	T-SR-01	17.1	23.0	34.0	33.5	88.8	91.3	2.5	2026	2026	0	Not Applicable
Rabbit Lake SS: Component Replacement	Execution	T-SR-01	3.6	5.0	8.3	9.2	29.3	36.7	7.5	2024	2025	1	Work Definition

Project Characteristics			2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Rexdale TS: M/C Switchgear & Component Replacement	Execution	T-SR-03	7.5	13.9	16.8	26.0	33.6	64.5	30.9	2026	2027	1	Execution Factors
Sarnia Scott TS: T5 & Component Replacement	Complete	T-SR-01	5.5	5.9	22.2	25.1	26.2	29.1	2.9	2024	2024	0	Execution Factors
Scarboro TS: T23 & Component Replacement	Execution	T-SR-03	4.7	4.5	0.0	3.3	23.3	27.0	3.7	2027	2026	-1	Execution Factors
Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement	Execution	T-SR-01	17.1	19.6	53.6	0.0	53.6	76.2	22.6	2024	2027	3	Work Definition
Slater TS: T2/T3 & Component Replacement	Complete	T-SR-03	3.2	9.1	5.3	11.7	28.3	24.8	-3.5	2024	2024	0	Not Applicable
Thorold TS: T1, MV Switchyard & Component Replacement	Complete	T-SR-03	1.3	6.7	3.1	9.6	31.8	43.8	12.1	2024	2024	0	Work Definition
Wawa TS: Component Replacement	Execution	T-SR-01	12.8	16.0	12.0	25.0	60.1	95.5	35.4	2026	2028	2	Execution Factors
Whitedog Falls SS: Component Replacement	Execution	T-SR-01	2.5	1.3	6.3	1.6	8.8	12.5	3.7	2025	2025	0	Work Definition
Wilson TS: T1 & Component Replacement	Complete	T-SR-03	5.3	7.3	46.0	49.0	46.0	49.3	3.3	2024	2024	0	Not Applicable
Wingham TS: T1, T2, PCT & Component Replacement	Complete	T-SR-03	5.3	6.7	13.0	17.2	23.0	34.1	11.1	2024	2024	0	Execution Factors
Overhead Lines Refurbishment Projects, Component Replacement Programs													
B7/B8 Transmission Line Refurbishment	Execution	T-SR-Other	2.5	0.7	3.2	0.0	3.2	8.8	5.6	2024	2025	1	Work Definition
A4L Transmission Line Refurbishment	Planning	T-SR-13	24.4	0.0	12.6	0.0	49.1	36.4	-12.7	2025	2033	8	Not Applicable
B5/6C Transmission Line Refurbishment	Execution	T-SR-13	3.9	4.2	0.0	13.4	24.0	22.6	-1.4	2025	2026	1	Not Applicable
D2/3H Transmission Line Refurbishment	Planning	T-SR-13	16.7	0.1	10.6	0.0	96.3	188.7	92.4	2026	2031	5	Work Definition
E1C Transmission Line Refurbishment	Planning	T-SR-13	14.0	0.1	8.3	0.0	55.2	68.0	12.8	2026	2031	5	Reprioritization
K1/K2 Transmission Line Refurbishment	Planning	T-SR-13	3.0	0.0	3.9	0.0	3.9	20.9	17.1	2024	2029	5	Reprioritization
K4 Transmission Line Refurbishment	Complete	T-SR-13	1.5	10.1	6.6	12.2	6.6	12.5	5.9	2024	2024	0	Work Definition
Q3M6 Transmission Line Refurbishment	Complete	T-SR-13	0.6	2.4	0.0	3.8	3.6	3.9	0.3	2024	2024	0	Not Applicable

Project Characteristics			2024 Tx Capital Expenditures ($M)		2024 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[11]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
L22H Transmission Line Refurbishment	Planning	T-SR-13	10.6	0.0	6.2	0.0	61.3	64.2	2.9	2026	2035	9	Not Applicable
Protection and Automation													
Cooksville Microwave Replacement	Complete	T-SR-Other	0.9	7.3	6.0	9.1	6.3	9.1	2.8	2024	2024	0	Execution Factors
Ottawa Ring 9 Fibre Infrastructure Development	Execution	T-SR-17	6.7	14.8	0.0	9.1	22.0	27.9	5.9	2026	2025	-1	Execution Factors
System Service													
Enabling Facilities - Government Project													
Keith TS: Replace 6-115 kV Breakers	Execution	T-SS-New	0.0	6.6	0.0	6.0	0.0	9.3	9.3	-	2025	n/a	Emergent Needs
Inter Area Network Capability													
Chatham SS x Lakeshore TS: Stations Work	Complete	T-SS-07	9.1	9.7	0.0	27.2	32.4	29.5	-2.8	2025	2024	-1	Not Applicable
Sudbury Area Reinforcement - X25S Unbundling	Complete	T-SS-Other	11.7	7.8	24.3	19.7	24.4	20.4	-4.0	2024	2024	0	Not Applicable
Local Area Supply Adequacy													
Barrie Area Transmission Upgrade	Complete	T-SS-Other	2.5	12.7	2.5	14.3	105.1	100.1	-4.9	2023	2023	0	Not Applicable
Richview x Trafalgar 230kV Conductor Upgrade	Execution	T-SS-04	11.7	21.1	20.0	19.1	59.3	82.6	23.3	2026	2026	0	Execution Factors

1

The following is an overview of the larger cost and schedule variances for projects with AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2).

The **Wawa TS: Component Replacement (T-SR-01)** project is forecasted to exceed its budget by $35.4M predominantly due to cost pressures outlined in Section 2.0, as well as design and staging plan maturity. Increased project complexity and requirements for several temporary line bypasses to accommodate a power-outage staging plan in the region also contributed to the variance. **Rexdale TS: M/C Switchgear & Component Replacement (T-SR-03)** is forecasted to exceed its budget by $30.9M primarily due execution factors including a more complex staging plan to align with Toronto Hydro's requirements, outage challenges, and unforeseen construction complexities related to in-situ equipment replacement. **Bridgman TS Load Station Transformer Replacement (T-SR-03)** is forecasted to exceed its budget by $26.1M due to changes in the contingency tie cable design to meet Toronto Hydro's requirements, constructability challenges, and Toronto Hydro's cost escalations for cable relocation work. These factors, along with material delivery delays and outage coordination requirements also led to schedule delays. **Richview x Trafalgar 230kV Conductor Upgrade (T-SS-04)** is forecasted to exceed its budget by $23.3M primarily due to changes in project definition assumptions including permit-related requirements, construction complexity crossing multiple highways and procurement escalations. Lastly, **Main TS: T3, T4 & Component Replacement (T-SR-03)** is forecasted to exceed its budget by $22.4M. The increase in cost is attributed to execution related challenges and equipment cost increases. The project is being undertaken in a congested urban setting resulting in unanticipated design and construction challenges, including major design changes, restricted resource movement and material flow, unanticipated underground obstructions, complex excavation shoring, and complex commissioning requirements. These factors, combined with permit delays, also led to a schedule delay from 2024 to 2025.

The following is an overview of the larger cost and schedule variances for projects that did not have an AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2). The **D2/3H Transmission Line Refurbishment (T-SR-13)** project is forecasted to exceed its budget by $92.4M. This project is in an early planning phase and is on hold as the project is assessed. **Otto Holden TS: T3/T4 &**

Component Replacement (T-SR-01) project is forecasted to exceed its budget by $38.8M mainly due to additional infrastructure needs. Two new autotransformers and a 115 kV yard must be installed in the new Antoine TS and connected to the existing Otto Holden TS through a short 230 kV transmission line. In addition, as the project has matured, scope changes were required to account for complex and high-risk outage requirements, OPG's safe site access requirements and impacts to the interconnection with Quebec, safety concerns with the condition of the existing property, and the unavailability of space for expansion. **Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement (T-SR-01)** is forecasted to exceed its budget by $22.6M due to a combination of project maturity and cost escalation factors related to scope changes which included location changes for all four transformers, and project adjustments to maintain the current medium-voltage switchyard, which also contributed to the schedule delay from 2024 to 2027. **Mackenzie TS: Component Replacement - Phase 1 (T-SR-01)** is forecasted to exceed its budget by $14.5M. This increase is primarily attributable to a combination of project maturity and execution related factors. Lastly, a subset of **Transmission Line Refurbishment (T-SR-13)** projects have been impacted by maturity and cost escalation factors and have subsequently been deferred to manage expenditures within the overall capital envelope.

5.0 PROGRAM PERFORMANCE

Overall, the aggregate capital expenditure and ISA amounts for System Renewal programs in Table 4 below were above the overall Forecast amounts (+$49M and +$36M respectively).

1

Table 4 - Transmission Program Summary

Program Characteristics		2024 Tx Capital Expenditures ($M)			2024 Tx In-Service Additions ($M)			2024 Tx Units				Performance
Program Description	EB-2021-0110 ISD Number	Forecast	Actual	Variance	Forecast	Actual	Variance	Unit Description	Forecast	Actual	Variance	Variance Category
System Renewal												
Wood Pole Structure Replacement	T-SR-04	56.5	88.7	32.2	56.2	86.1	29.9	# of Structures	943	952	9	Execution Factors
Steel Structure Coating Program	T-SR-05	19.7	27.7	8.1	19.7	27.9	8.2	# of Structures	470	504	34	Execution Factors
Tx Lines Foundation Assess/Clean/Coat, Life Extension & Tower Member Refurbishment Program	T-SR-06	14.2	17.8	3.7	14.1	18.1	3.9	# of Structures	1329	1459	130	Reprioritization
Transmission Line Shieldwire Replacement	T-SR-07	13.0	19.9	7.0	12.9	20.9	8.0	# of km	297	190	-107	Work Definition
Transmission Line Insulator Replacement	T-SR-08	77.5	64.3	-13.2	81.3	66.4	-14.9	# of Circuit Structures	3694	3084	-610	Not Applicable
Transmission Station Demand, Spares and Targeted Assets	T-SR-09	65.7	71.3	5.6	49.8	57.5	7.7	n/a	n/a	n/a	n/a	Reprioritization
Protection Relay Replacement Program	T-SR-10	10.4	11.4	1.0	9.8	1.4	-8.4	# of Upgrades	45	8	-37	Execution Factors
Tx Lines Emergency Replacements	T-SR-15	11.0	8.0	-2.9	10.7	7.8	-2.9	# of work orders	115	87	-28	Execution Factors
Tx Lines Virtual Asset Inspection	T-SR-Other	3.0	9.3	6.3	3.0	5.4	2.4	CCT-Km inspected	2210	15770	13560	Reprioritization
Tx Lines - TC112 ROW projects	T-SR-Other	2.5	4.1	1.5	2.5	4.5	2.0	# of Asset Structures	10	9	-1	Work Definition
Tx RTU Replacement Program	T-SR-Other	6.7	6.2	-0.5	4.2	2.9	-1.3	# of RTUs	8	6	-2	Execution Factors
Online DGA Monitor Program	T-SR-Other	3.1	3.4	0.4	3.1	4.5	1.4	# of Installations	14	18	4	Execution Factors

2

The **Wood Pole Structure Replacement (T-SR-04)** program had higher expenditures due to difficult terrain and access, and higher contract costs associated with accessing and setting up remote work headquarters (e.g. ice roads, bypasses, helicopter deliveries). These higher expenditures were partially funded through redirection from the **Transmission Lines Insulator Replacement (T-SR-08)** program, as outage constraints and cancellations deferred planned work.

Other programs that experienced material variances were:

- The **Steel Structure Coating (T-SR-05)** program had higher expenditures due to the work complexity and higher than forecasted costs for live-line work.
- The **Tx Lines Foundation Assess/Clean/Coat, Life Extension & Tower Member Refurbishment (T-SR-06)** program had higher expenditures mainly due to additional units that were completed.
- The **Transmission Shieldwire Replacement (T-SR-07)** program had higher expenditures and reduced accomplishment due to more complex work including OPGW replacement rather than shieldwire, which is more costly due to tower peak modifications and required fibre optic cable work.
- The **Transmission Station Demand, Spares and Targeted Assets (T-SR-09)** program had increased expenditures to purchase a spare transformer unit that was originally planned for 2025.
- The **Protection Relay Replacement (T-SR-10)** program had higher expenditures due to the advancement of construction work; outage availability limited work completion (unit accomplishments and ISA), which are now expected to be completed in future years.
- **Tx Lines Emergency Replacements (T-SR-15)** had lower expenditures and accomplishments due to fewer emergency failures.
- The **Transmission Lines Virtual Asset Inspection (T-SR-Other)** program had higher expenditures and accomplishment due to additional inspections.
- **Tx Lines - TC112 ROW Projects (T-SR-Other)** had higher expenditures as most of the work was bridge related which is more expensive and takes longer to complete.
- The **RTU Replacement Program (T-SR-Other)** had lower accomplishments due to work deferral to 2025 as a result of complex outage requirements and resourcing.

- The **Online DGA Monitor (T-SR-Other)** program had trailing ISA and accomplishments from 2023. Capital expenditures were undertaken in 2023 but could not be in-serviced due to outage and construction constraints. This resulted in higher ISA and accomplishments in 2024 despite capital expenditures being close to plan.

SECTION 2.9 – ATTACHMENT 5 – TRANSMISSION CAPITAL PERFORMANCE REPORT – 2025

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report (CPR) provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2025 in relation to the overall transmission capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISAs) 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 (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 ISAs.[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 (Forecast). This was the first time Hydro One allocated the impact of the Settlement Proposal at 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

Table 1 below presents a breakdown of the actual 2025 transmission capital expenditures and ISAs by OEB investment category and compares them to the OEB-approved values. The primary focus of this report is on the Transmission System Access, System Renewal,

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

and System Service categories. The Transmission General Plant category is discussed in the General Plant Capital Performance Report.

Table 1 - 2025 Transmission 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	63.0	148.9	85.9	63.9	99.2	35.3
System Renewal	1,172.4	1,103.7	-68.7	1,334.2	1,168.1	-166.1
System Service	90.3	141.0	50.7	172.3	77.3	-94.9
General Plant	111.8	111.0	-0.8	125.7	134.6	8.9
Productivity[4]	-64.2	-	64.2	-64.2	-	64.2
Total	**1,373.3**	**1,504.6**	**131.3**	**1,631.8**	**1,479.3**	**-152.5**

In 2025, Hydro One's transmission capital expenditures for 2025 were 9.6% above the OEB-approved amount and ISAs were 9.3% below the OEB-approved amount. Transmission capital expenditures were higher largely due to increased spending in the System Access and System Service categories. Increased expenditures in System Service were primarily driven by mandatory transmission work required by governmental authorities (externally driven work). The decrease in transmission ISAs was due to lower System Renewal additions. 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. The OEB categories and associated variance explanations are summarized below.

System Access: System Access capital expenditures were $85.9M above the OEB-approved amount. This variance was primarily driven by Centennial TS connection (T-SA-Other), where the customer has selected the province of Ontario and the City of St Thomas

[2] Does not include Hydro One affiliates or future Affiliate Transmission Lines Projects (ATP).
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 (Table 22 and 23)
[4] Productivity is reflected in Actual expenditures.

in which to invest $7.0B in a large-scale EV battery manufacturing facility. The proposed connection plan to supply the customer facility consists of building two new 230 kV double-circuit transmission line taps and a new 230/27.6 kV transmission station. The variance was also caused by Belleville TS: Build 75/125 MVA, 230/44 kV DESN project (T-SA-Other) which is required to provide additional capacity in the region of Belleville as the projected load is expected to exceed the current capacity available from the existing Belleville TS. System Access ISAs were $35.3M above the OEB-approved amount primarily due to the addition of Wallaceburg TS: Conversion from 115 kV to 230 kV (T-SA-Other) to support the St. Clair Transmission Line project as directed by the Independent Electricity System Operator (IESO).

System Renewal: System Renewal capital expenditures were $68.7M below the OEB-approved amount. This variance was primarily driven by the deferral of several transmission line refurbishment projects (T-SR-13), including the refurbishments of L22H Easton Junction x Hinchinbrook, A4L Beardmore x Longlac TS, D2/3H Hunta SS x Abitibi Canyon Junction and T33E Almonte TS x Oshawa North Junction. The variance was also caused by a reduction in the Transmission Lines Insulator Replacement Program (T-SR-08) which experienced system outage constraints and the diversion of crews to storm and wildfire restoration work.

System Renewal ISAs were $166.1M below the OEB-approved amount due to the factors noted above, along with scope reduction and re-pacing of the Gardiner TS: T1/T2 PCT Component Replacement project (T-SR-03) due to equipment failure which shifted the expected in-service year from 2025 to 2026. The System Renewal ISA decrease was partially offset by the acceleration of the Bruce A 500kV Switchyard Replacement project (T-SR-02), which achieved a project milestone in 2025, and reflects $337.9M of ISAs that were not included in the 2025 Forecast.

System Service: System Service expenditures were $50.7M above the OEB-approved amount. This variance was primarily driven by the advancement of planning work for St. Clair Transmission Line: Stations Work (T-SS-09) and the refinement of execution

methods for Richview Manby Transmission Reinforcement – Line (T-SS-06) to minimize disruption to the community.

System Service ISAs were $94.9M below the OEB-approved amount primarily driven by Chatham SS x Lakeshore TS: Stations Work (T-SS-07) which was completed a year ahead of schedule.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM LEVEL

Hydro One takes an integrated approach to transmission portfolio management and manages to the overall capital envelope. The approach recognizes that changes at both the project and program levels will occur. Individual variances, whether at the annual or project total level, are to be expected given the magnitude and complexity of the work being performed. Each project involves a unique combination of elements related to the scope of work included and site conditions and is undertaken pursuant to a defined project delivery process with a range of expected outcomes as defined by the Association for the Advancement of Cost Engineering (AACE) class of estimate.[5] Projects are typically released for execution and funded based on a Class 3 estimate. As projects are executed, they are managed to allow Hydro One to be responsive to execution challenges and update project scope, where required, while continuing to deliver the projects according to Hydro One's project delivery process.

At Hydro One, projects are governed with a focus on adherence to the total project budget. In-year amounts are managed from a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in this report in reference to project total variances and overall project schedule variances. Programs are different in that the budget is set annually and are managed and governed against these budgets. As such, program performance is discussed in the context of adherence to annual budgets.

[5] AACE estimate classification is discussed in TSP Section 2.11.

3.1 OVERVIEW

The projects and programs discussed in this report represent 95% of the 2025 actual ISAs that are 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.

Hydro One's performance in relation to material[6] projects with AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2), is presented in Figure 1 below.[7] The blue vertical lines in the cost variance chart are placed at -20% and +30% which represent the range of expected outcomes that most commonly aligns with an AACE Class 3 estimate, and are representative of the typical project definition work completed at the time of business case approval at Hydro One. The figure shows a relatively tight dispersion of cost performance with the majority of projects (71%, or 15 of 21) having project variances below the AACE upper range, which is a reasonable result given the significant cost pressures experienced in recent years and is an improvement relative to 2024. The overall variance for the 21 projects is +8% which is within the AACE Class 3 estimate range. Hydro One utilizes its Capital Project Delivery model to manage and remain effective in executing projects within the range anticipated when the project budgets were established. This is particularly true for larger projects that are subject to increased rigour and scrutiny as part of the project delivery process.

[6]Greater than or equal to $4M, and with actual or planned ISA in 2025
[7] This provides a more consistent evaluation of AACE Class 3-based project estimates against the AACE Class 3 estimate accuracy range.

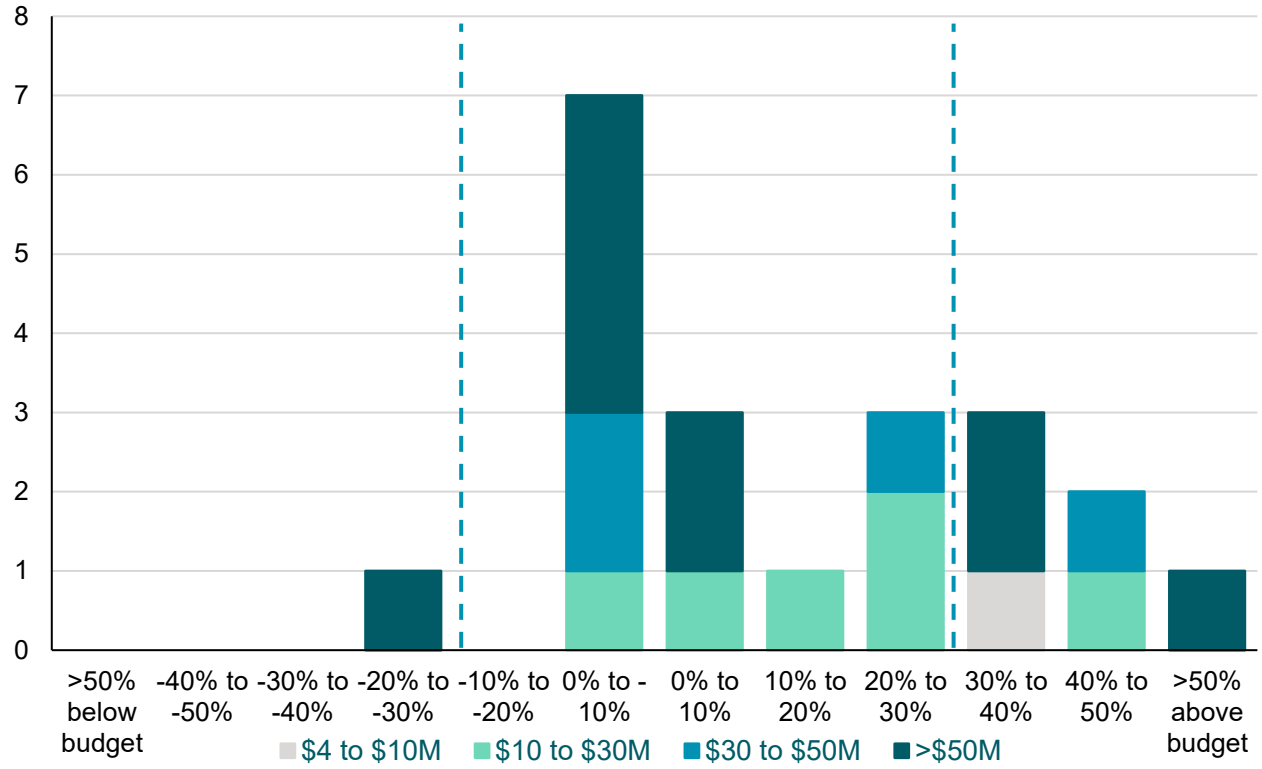

Figure 1: Material Project Cost Variance Dispersion[8]

Similarly, Figure 2 shows that the majority of projects (57%, or 12 of 21) were completed or are forecast to complete on plan, within 12 months of baseline.

[8] Based on actual cost for completed projects and forecast cost at completion for projects still in progress.

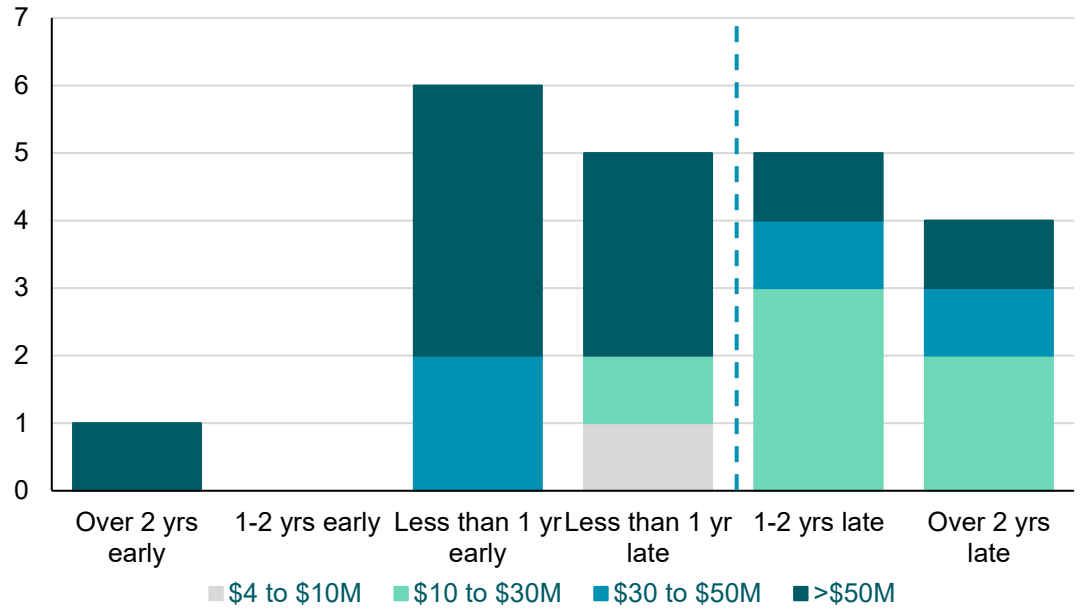

Figure 2: Material Projects Schedule Variance Dispersion[9]

3.2 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISAs in 2025 greater than or equal to $4M have been summarized in the tables below, along with variance explanations. The thresholds used by Hydro One to identify material variances were determined using the following criteria[10]:

- **Cost Variances** – Material cost variances were identified where the in-year cost variance for a program, or the total project end cost variance was greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – 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.

[9] Based on actual in-service date for completed projects and forecast in-service date for projects still in progress.
[10] 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.

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 makes in response to a change in 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, or priorities that need to be addressed during execution. As risks materialize, plans are adjusted to accommodate the change and mitigate the overall impact on cost, schedule, and resources. This can change the year in which the project goes in-service without materially changing the ISA or affecting the overall scope 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 to the project cost as a result of new or changing information that becomes known during the design and estimate and execution phases.

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 PROJECT PERFORMANCE

As summarized in Table 3 below, transmission projects are managed with a focus on adherence to the overall project total budget and project schedule.

1

Table 3 - Transmission Project Summary

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[11]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
System Access													
Generator Customer Connection													
Hagersville Battery Storage -ELT1	Complete	T-SA-Other	0.0	3.5	0.0	4.1	0.0	4.1	4.1	-	2025	-	Emergent Needs
Load Customer Connection													
Bayfront Facility - EAF Project	Planning	T-SA-Other	21.2	0.0	49.0	0.0	49.0	25.6	-23.4	2025	2030	5	Reprioritization
Islington TS New 230 kV Customer Connection	Complete	T-SA-01	0.0	9.5	18.0	21.7	18.0	21.7	3.7	2025	2025	0	Execution Factors
South Middle Road TS DESN 2: 230/27.6 kV DESN	Complete	T-SA-10	3.8	3.0	44.1	39.2	44.8	41.9	-2.8	2025	2025	0	Not Applicable
Wallaceburg TS: Conversion from 115 kV to 230 kV	Execution	T-SA-Other	0.0	13.5	0.0	28.7	0.0	39.9	39.9	-	2028	-	Emergent Needs
System Renewal													
Integrated Station Investment													
Algoma TS: Component Replacement	Planning	T-SR-01	7.0	0.0	7.4	0.0	30.9	25.8	-5.1	2027	2034	7	Not Applicable
Beck 1 SS: ABCB Replacement	Execution	T-SR-02	9.0	3.7	29.9	9.3	54.2	38.3	-15.9	2026	2026	0	Not Applicable
Bracebridge TS: T1 & Component Replacement	Complete	T-SR-03	3.0	11.6	0.0	18.0	8.2	18.4	10.2	2026	2025	-1	Work Definition
Bridgman TS Load Station Transformer Replacement	Execution	T-SR-03	0.0	9.2	0.0	9.0	69.3	91.0	21.7	2024	2026	2	Execution Factors

[11] Phases: Planning, Execution, Complete, or Cancelled.

Witness: Scott Vicary; Donna Jablonsky; Mark Brodie

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Bruce A TS: 500 kV Switchyard Replacement	Execution	T-SR-02	44.4	88.9	0.0	337.9	316.2	487.8	171.6	2027	2027	0	Execution Factors
Bruce B SS: ABCB Replacement	Complete	T-SR-02	0.0	3.6	0.0	4.2	182.3	177.4	-4.9	2024	2022	-2	Not Applicable
Charles TS: T3, T4 & Component Replacement	Execution	T-SR-03	8.3	3.2	19.9	0.0	27.9	48.7	20.9	2026	2027	1	Work Definition
Cherrywood TS: 500 kV ABCB Replacement (Phase 3-1)	Complete	T-SR-02	2.2	2.6	7.0	4.2	74.8	72.1	-2.7	2025	2025	0	Not Applicable
Claireville TS: Component Replacement	Execution	T-SR-01	0.9	1.6	5.3	2.6	27.9	35.9	7.9	2025	2026	1	Execution Factors
Crowland TS: T5, T6 & Component Replacement	Cancelled	T-SR-03	11.6	0.1	33.2	0.0	33.9	-	-	2026	-	-	Not Applicable
Duplex TS: T1, T2, T3, T4 & Component Replacement	Planning	T-SR-03	9.8	0.1	9.3	0.0	22.3	89.0	66.7	2026	2034	8	Work Definition
Elliot Lake TS: Component Replacement	Execution	T-SR-03	7.5	8.0	11.5	0.0	23.5	33.7	10.3	2026	2026	0	Work Definition
Gardiner TS: T1, T2, PCT & Component Replacement	Execution	T-SR-03	26.0	21.6	61.9	0.0	61.9	39.5	-22.4	2025	2026	1	Emergent Needs
Glendale TS: Station Refurbishment and Reconfiguration	Planning	T-SR-03	8.5	0.6	9.7	0.0	52.9	32.4	-20.5	2027	2031	4	Not Applicable
Hunta SS: Component Replacement	Planning	T-SR-01	4.7	0.1	9.4	0.0	10.9	14.6	3.7	2025	2030	5	Reprioritization
John TS: T5 and T6 Transformer Replacement	Complete	T-SR-03	9.0	9.1	15.7	27.5	25.9	27.5	1.6	2025	2025	0	Not Applicable
Kirkland Lake TS: Component Replacement	Execution	T-SR-03	2.5	3.7	8.0	6.1	27.9	35.9	8.0	2025	2027	2	Execution Factors
Lake TS: T2 & Component Replacement	Complete	T-SR-03	8.1	0.2	8.0	0.2	39.9	11.9	-28.0	2026	2024	-2	Not Applicable
Lauzon TS: T6, T5 & Component Replacement	Execution	T-SR-03	10.8	31.3	32.0	42.7	64.1	69.5	5.5	2026	2026	0	Not Applicable

Witness: Scott Vicary; Donna Jablonsky; Mark Brodie

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Lennox TS: ABCB Component Replacement	Complete	T-SR-02	10.7	8.1	11.0	8.2	143.2	148.0	4.8	2026	2025	-1	Not Applicable
Lisgar TS: T1 and Component Replacement	Execution	T-SR-03	0.0	7.5	0.0	7.3	18.1	15.0	-3.1	2031	2026	-5	Not Applicable
Longueuil TS: T3, T4 Component Replacement	Complete	T-SR-03	10.5	9.6	0.0	28.4	24.9	29.5	4.6	2026	2025	-1	Execution Factors
Longwood TS: Component Replacement	Execution	T-SR-03	0.7	1.5	14.7	1.7	14.7	16.3	1.6	2025	2026	1	Work Definition
Mackenzie TS: Component Replacement - Phase 1	Complete	T-SR-01	15.7	18.6	28.3	60.7	47.3	60.9	13.6	2025	2025	0	Work Definition
Main TS: T3, T4 & Component Replacement	Execution	T-SR-03	2.6	13.9	2.6	36.7	48.0	67.3	19.2	2024	2026	2	Execution Factors
Marathon TS: Component Replacement	Execution	T-SR-01	11.1	2.5	11.3	0.0	30.7	36.6	5.9	2026	2028	2	Work Definition
Merivale TS Refurbishment	Execution	T-SR-01 T-SS-05	58.0	88.6	0.0	63.0	297.4	281.0	-16.4	2027	2029	2	Not Applicable
Middleport TS: ABCB Replacement	Complete	T-SR-02	10.0	7.5	34.6	8.1	178.1	165.5	-12.5	2025	2025	0	Not Applicable
Middleport TS: T6 Replacement	Complete	T-SR-01	6.1	14.5	25.4	16.4	24.9	25.7	0.8	2025	2025	0	Not Applicable
Midhurst TS: T4 & Component Replacement	Planning	T-SR-03	3.7	0.0	8.7	0.0	11.0	17.0	6.0	2025	2032	7	Reprioritization
Milton SS: Component Replacement	Execution	T-SR-01	0.0	3.1	0.0	5.9	20.0	28.8	8.9	2024	2028	4	Execution Factors
Murray TS: T11, T12 & Component Replacement	Planning	T-SR-03	17.0	0.9	38.1	0.0	39.6	60.8	21.3	2025	2032	7	Reprioritization
Nanticoke TS: ABCB Replacement	Execution	T-SR-02	6.6	8.0	15.0	10.8	79.0	81.9	2.9	2026	2027	1	Not Applicable
Newton TS: HV Breakers & Component Replacement	Cancelled	T-SR-03	5.4	0.1	13.7	0.0	13.8	-	-	2025	-	-	Not Applicable
Orillia TS: Component Replacement	Execution	T-SR-03	4.8	12.1	11.0	0.0	11.0	31.2	20.3	2025	2026	1	Work Definition

Witness: Scott Vicary; Donna Jablonsky; Mark Brodie

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Otto Holden TS: T3/T4 & Component Replacement	Execution	T-SR-01	12.2	29.6	11.3	2.7	68.7	102.4	33.7	2027	2028	1	Work Definition
Palermo TS: T3, T4 Replacement & Station Expansion	Execution	T-SR-03	7.0	7.8	7.2	0.0	34.3	54.7	20.5	2027	2027	0	Work Definition
Porcupine TS: Component Replacement	Execution	T-SR-01	23.5	13.7	34.0	32.5	88.8	86.9	-1.9	2026	2026	0	Not Applicable
Preston TS: T3, T4 & Component Replacement	Execution	T-SR-03	10.8	24.6	11.3	28.5	23.7	52.0	28.3	2026	2027	1	Work Definition
Russell TS: T1, T2 & Component Replacement	Execution	T-SR-03	12.4	13.2	10.8	0.0	28.6	41.9	13.3	2026	2027	1	Work Definition
Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement	Execution	T-SR-01	0.0	22.7	0.0	53.5	53.6	70.0	16.4	2024	2027	3	Work Definition
Strachan TS: T14 & Component Replacement	Execution	T-SR-03	0.2	2.3	10.9	0.0	10.9	16.6	5.7	2025	2027	2	Execution Factors
Wawa TS: Component Replacement	Execution	T-SR-01	16.9	19.5	21.0	3.7	60.1	99.0	38.9	2026	2029	3	Execution Factors
Whitedog Falls SS: Component Replacement	Complete	T-SR-01	0.1	4.5	0.0	8.9	8.8	12.1	3.3	2025	2025	0	Work Definition
Wonderland TS: T5, PCT & Component Replacement	Cancelled	T-SR-03	11.7	0.0	12.5	0.0	27.0	-	-	2026	-	-	Not Applicable
Overhead Lines Refurbishment Projects, Component Replacement Programs													
A4L Transmission Line Refurbishment	Planning	T-SR-13	23.8	0.0	36.4	0.0	49.1	35.6	-13.5	2025	2031	6	Reprioritization
B5/6C Transmission Line Refurbishment	Execution	T-SR-13	3.1	1.6	17.2	2.8	24.0	24.0	0.0	2025	2026	1	Execution Factors
D2/3H Transmission Line Refurbishment	Planning	T-SR-13	19.1	0.1	22.2	0.0	96.3	189.2	92.9	2026	2031	5	Work Definition
D6 Transmission Line Refurbishment	Execution	T-SR-13	1.7	1.3	7.3	0.0	42.8	55.6	12.8	2025	2028	3	Execution Factors
E1C Transmission Line Refurbishment	Planning	T-SR-13	17.3	0.1	19.2	0.0	55.2	67.9	12.7	2026	2031	5	Reprioritization

Witness: Scott Vicary; Donna Jablonsky; Mark Brodie

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[11]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
E8V/E9V Transmission Line Refurbishment	Planning	T-SR-13	13.0	0.0	7.2	0.0	61.9	25.0	-36.9	2027	2031	4	Not Applicable
H1L/H3L/H6LC/H8LC Transmission Line Refurbishment	Planning	T-SR-13	3.2	0.0	6.0	0.0	6.0	17.5	11.4	2025	2031	6	Reprioritization
L22H Transmission Line Refurbishment	Planning	T-SR-13	26.8	0.0	24.7	0.0	61.3	64.5	3.2	2026	2035	9	Not Applicable
M6/7E Transmission Line Refurbishment	Cancelled	T-SR-13	12.8	0.0	7.1	0.0	26.8	-	-	2026	-	-	Not Applicable
N5K Transmission Line Refurbishment[12]	Cancelled	T-SR-13	10.9	0.0	7.4	0.0	34.8	-	-	2027	-	-	Not Applicable
Q2AH Transmission Line Refurbishment	Planning	T-SR-13	3.9	0.0	9.7	0.0	9.7	11.5	1.9	2025	2031	6	Reprioritization
S2N Transmission Line Refurbishment	Planning	T-SR-13	7.0	0.0	7.2	0.0	29.6	22.6	-7.0	2027	2031	4	Not Applicable
T33E Transmission Line Refurbishment	Planning	T-SR-13	18.2	0.0	15.3	0.0	118.3	230.2	111.9	2027	2032	5	Reprioritization
Protection and Automation													
Ottawa Ring 9 Fibre Infrastructure Development	Execution	T-SR-17	5.6	6.3	0.0	14.3	22.0	24.5	2.5	2026	2026	0	Execution Factors
Telecom Performance - Ring 6 OPGW (B22D,Hannover)	Planning	T-SR-12	4.0	0.0	11.1	0.0	11.1	29.4	18.3	2025	2030	5	Reprioritization
System Service													
Enabling Facilities - Government Project													
Keith TS: Replace 6-115 kV Breakers	Complete	T-SS-Other	0.0	3.3	0.0	4.5	0.0	10.5	10.5	-	2025	-	Emergent Needs
Inter Area Network Capability													

[12] Project being addressed as part of the St. Clair Transmission Line project

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[11]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
Chatham SS x Lakeshore TS: Stations Work	Complete	T-SS-07	3.9	0.9	32.4	0.9	32.4	29.5	-2.9	2025	2024	-1	Not Applicable
Local Area Supply Adequacy													
Richview Manby Transmission Reinforcement - Line	Execution	T-SS-06	12.3	19.7	0.0	35.3	32.6	61.6	28.9	2026	2026	0	Work Definition
Richview x Trafalgar 230 kV Conductor Upgrade	Complete	T-SS-04	9.5	16.2	0.0	28.6	59.3	80.3	21.0	2026	2025	-1	Execution Factors

The following is an overview of the more significant cost and schedule variances for projects that had AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2).

The **Wawa TS: Component Replacement (T-SR-01)** project is forecast to exceed its budget by $38.9M, predominantly due to input cost pressures and increased project complexity including requirements for several temporary line bypasses to accommodate a power-outage staging plan in the region. **Bridgman TS Load Station Transformer Replacement (T-SR-03)** is forecast to exceed its $69.3M budget by $21.7M for a latest total project forecast of $91.0M due to changes in the contingency tie cable design to meet Toronto Hydro's requirements, design maturity, constructability challenges, and cost escalations for cable relocation work completed by Toronto Hydro. These factors, along with material delivery delays and outage management constraints, led to a schedule delay as well, shifting project completion from 2024 to 2026. However, project savings of approximately $8.0M were realized through value engineering and risk management, reducing the overall project cost and mitigating additional cost pressures. **Richview x Trafalgar 230 kV Conductor Upgrade (T-SS-04)** was completed above budget by $21.0M, primarily due to changes in project definition assumptions, including permit-related requirements, construction complexity associated with crossing multiple highways and procurement escalations. Through partial in-servicing and risk management, cost savings of approximately $5.0M were realized, helping to offset cost pressures.

The **Beck 1 SS: ABCB Replacement (T-SR-02)** project is forecast to be completed $15.9M below budget due to the reduced impact of execution factors. This was achieved through effective project execution, enhanced stakeholder coordination, and construction optimization initiatives. Similarly, **Middleport TS: ABCB Replacement (T-SR-02)** project was completed $12.5M below budget due to construction efficiency and effective risk management, and scope optimization. The use of pre-built and partially commissioned panels enabled work to be completed ahead of outages, ensuring that outage windows could be executed as planned and mitigating project risk.

The following is an overview of the more significant cost and schedule variances for projects that did not have an AACE Class 3 estimate at the time the Settlement Proposal was implemented (see Section 1.2).

The Bruce A TS: 500kV Switchyard Replacement (T-SR-02) project is forecast to exceed its $316.2M budget by $171.6M based on the latest total project forecast of $487.8M, with the forecast in-service year remaining as 2027. The original forecast for the 500kV gas insulated switchgear (GIS) was developed based on an earlier investment at the Bruce Nuclear Complex, using pre-pandemic prices. The specialized nature of the required GIS and post-pandemic market forces resulted in higher actual costs for the required equipment. Additional scope was added to the project as well to improve reliability, operational flexibility, and maintainability. Following scope development, an AACE Class 3 estimate was completed with a value of $516.5M and is now forecast to be completed $28.7M below the estimate ($487.8M). Through accelerating the ISAs, the contingency and commissioning costs were lowered, effectively reducing the overall project cost by approximately $30M. Several **Transmission Line Refurbishment (T-SR-13)** projects have experienced cost increases due to maturity and cost escalation factors, and have subsequently been deferred to manage expenditures toward the overall capital envelope, notably T33E Transmission Line Refurbishment and D2/3H Transmission Line Refurbishment. **Duplex TS: T1, T2, T3, T4 & Component Replacement (T-SR-03)** is forecast to exceed its $22.3M budget by $66.7M, with the latest total project forecast of $89.0M, due to updated estimates based on recent comparable projects and the incorporation of scope from another investment at the same site. The integrated scope includes the replacement of two additional transformers and associated end-of-life equipment.

The **Lake TS: T2 & Component Replacement (T-SR-03)** project was completed $28.0M below budget due to a reduction in scope. The original scope included the replacement of three transformers; however, following an opportunity to acquire adjacent land, two of the transformers were moved to a separate future investment at the site. This approach significantly reduced safety, staging, and outage risks while providing flexibility for future

load growth. Similarly, **Gardiner TS: T1, T2, PCT & Component Replacement (T-SR-03)** project is forecast to be completed $22.4M below budget due to scope optimization that prioritized the highest risk assets (i.e. transformers), deferring PCT equipment and medium voltage switchgear replacement to a separate investment. Further savings were realized through construction efficiencies and the use of spare materials from other projects. **Merivale TS Refurbishment (T-SR-01 / T-SS-05)** project is forecast to be completed $16.4M below budget due to contract management where a separate supply vendor and installation general contractor approach was used to balance risk-reward and improve overall cost competitiveness. Additional savings were achieved through early outage availability that accelerated the completion of the west yard a month ahead of schedule, as well as execution efficiencies including design optimization, re-use of existing facilities, and optimized construction sequencing.

5.0 PROGRAM PERFORMANCE

Consistent with the previously discussed reprioritization of work in the System Renewal category to accommodate pressures across the portfolio, aggregate capital expenditure and ISAs for System Renewal programs in Table 4 were below the overall Forecast amounts by -$21.6M and -$16.0M, respectively. This reflects the reprioritization of work toward mandatory, customer-driven, and other high-priority investments while continuing to operate towards the OEB-approved expenditure envelope.

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Table 4 - Transmission Program Summary

Program Characteristics		2025 Transmission Capital Expenditures ($M)			2025 Transmission In-Service Additions ($M)			2025 Tx Units				Performance
Program Description	EB-2021-0110 ISD Number	Forecast	Actual	Variance	Forecast	Actual	Variance	Unit Description	Forecast	Actual	Variance	Variance Category
System Renewal												
Wood Pole Structure Replacement	T-SR-04	57.6	60.6	2.9	57.5	69.1	11.6	# of Structures	944	820	-124	Execution Factors
Steel Structure Coating Program	T-SR-05	20.0	0.4	-19.7	20.0	0.1	-19.9	# of Structures	478	0	-478	Reprioritization
Tx Lines Foundation Assess/Clean/Coat, Life Extension & Tower Member Refurbishment Program	T-SR-06	14.4	14.7	0.3	14.4	14.4	0.0	# of Structures	1354	1363	9	Not Applicable
Transmission Line Shieldwire Replacement	T-SR-07	13.2	20.4	7.2	13.2	18.9	5.8	# of km	297	274	-23	Work Definition
Transmission Line Insulator Replacement	T-SR-08	79.0	53.7	-25.3	78.6	48.3	-30.4	# of Circuit Structures	3690	2536	-1154	Reprioritization
Transmission Station Demand, Spares and Targeted Assets	T-SR-09	72.9	77.1	4.2	58.9	77.3	18.4	N/A	N/A	N/A	N/A	Execution Factors
Protection Relay Replacement Program	T-SR-10	10.5	19.2	8.7	10.4	12.1	1.7	# of Upgrades	45	48	3	Execution Factors
Tx Lines Emergency Replacements	T-SR-15	11.2	12.8	1.6	11.0	10.9	-0.2	# of Work Orders	115	74	-41	Execution Factors
Fiber Entrance Installation and Completion of OPGW	T-SR-17	6.9	0.8	-6.1	4.1	0.7	-3.4	N/A	N/A	N/A	N/A	Not Applicable
Tx RTU Replacement Program	T-SR-Other	6.9	11.5	4.6	6.8	7.2	0.4	# of RTUs	8	14	6	Execution Factors

Witness: Scott Vicary; Donna Jablonsky; Mark Brodie

Reductions in both expenditures and accomplishments are noted in the **Transmission Line Insulator Replacement (T-SR-08)** and **Steel Structure Coating (T-SR-05)** programs due to reprioritization of work, along with system outage constraints. For the Transmission Line Insulator Replacement program, the diversion of crews to storm and wildfire restoration work was also a factor.

Other programs that experienced material variances were:

- The **Wood Pole Structure Replacement (T-SR-04)** program had higher expenditures and ISAs because of carry-over work and partial completions were capitalized.
- The **Transmission Line Shieldwire Replacement (T-SR-07)** program had higher expenditures and reduced accomplishment due to more complex work, including the replacement of shieldwire with optical ground wire (OPGW), which is more costly due to tower peak modifications and required fibre optic cable work.
- The **Transmission Station Demand, Spares and Targeted Assets (T-SR-09)** program had higher expenditures due to the early delivery of a transformer.
- The **Protection Relay Replacement (T-SR-10)** program had higher expenditures due to work deferred from the previous year to 2025 to accommodate priority investments and the transfer of costs to the program associated with Bunting TS Standard Development that were not included in the original budget.
- **Transmission Lines Emergency Replacements (T-SR-15)** had higher expenditures due to wildfire restoration work, which resulted in more expensive repairs and lower accomplishments due to fewer emergency failures and outage constraints.
- The **Remote Terminal Unit** (**RTU) Replacement (T-SR-Other)** program had higher expenditures and accomplishments due to work deferred to 2025 from the previous year and work advanced from 2026 due to resource availability.

SECTION 2.10 – TSP – HOSSM CAPITAL SYSTEM PLAN

2.10.1 INTRODUCTION

The sections in this Exhibit form Hydro One Sault Ste. Marie's (HOSSM) six-year System Plan for the 2027 to 2032 planning period.[1]

In 2016, Hydro One Inc. received OEB approval to acquire Great Lakes Power Transmission LP (which was subsequently renamed HOSSM), as well as approval for a ten-year deferred rebasing period. Since October 1, 2018, and as further described below, HOSSM has been operationally integrated with Hydro One Transmission. However, HOSSM will remain financially and legally separate until such time that a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One. See Exhibit A-08-01 for more details.

HOSSM continues to be the licensed owner and operator of its transmission system, but relies on Hydro One to carry out the day-to-day operations, pursuant to affiliate service agreements as outlined in Exhibit D-02-03. Although HOSSM is distinct and its approved revenue requirement is established separately, many processes including the asset management, planning and work execution approaches are common and integrated with Hydro One Transmission and are described within Hydro One's SPF and TSP.

2.10.2 HOSSM SYSTEM PLAN OVERVIEW

This section summarizes the key components that make up HOSSM's system plan and contextualizes the quantitative and qualitative information provided throughout.

2.10.2.1 KEY ELEMENTS OF THE PLAN

HOSSM strives to provide safe and reliable grid operations on a 24/7 basis. As the lead transmitter in the East Lake Superior region, HOSSM's transmission system plan provides capacity and reliability enhancements to accommodate existing load and growth. Over the

[1] EB-2026-0170, Decision and Order, 14 July 2026: The OEB approved HOSSM's 2027 revenue requirement on an interim basis; 2027-2032 are being rebased as part of this Application.

2027-2032 period, HOSSM plans to invest an average of $32M per year in transmission capital, for a total of $192M, to respond to a range of asset and system needs, and to meet customer service imperatives. Further details on HOSSM's capital plan are presented in section 2.10.9.

HOSSM's proposed OM&A funding will ensure that its assets are operated and maintained in accordance with good utility practice and reliability standards. HOSSM's forecast OM&A expenditures are discussed in Exhibit E-02-06.

2.10.2.2 OVERVIEW OF ASSETS MANAGED

This section summarizes the detailed characteristics and data on the assets covered by the asset management process, including service area, system configuration, asset condition, and asset utilization.

2.10.2.3 SCOPE OF THE TRANSMISSION SYSTEM

HOSSM owns and operates high-voltage assets in the Algoma District, along the eastern shore of Lake Superior, from the municipality of Wawa throughout the city of Sault Ste. Marie, to Echo Bay, Ontario, as depicted in Figure 1.

HOSSM's transmission infrastructure consists of 554 circuit-km of overhead lines, transmitting electricity throughout the Lake Superior Region. HOSSM's transmission infrastructure forms part of the North American bulk electric system (BES), making it subject to mandatory compliance with North American Electric Reliability Corporation (NERC) standards, which determine the required reliability (i.e., adequacy and security) of the BES under most system conditions.

In 2025, HOSSM transmitted 1.464 TWh of electricity from supply points (i.e., generation) to consumers of electricity in Ontario, supplying power to nine transmission connected customers, including three local distribution companies (LDCs) - Algoma Power Inc., PUC Distribution and Hydro One Distribution.

HOSSM's service area is situated in Northern Ontario, subjecting HOSSM's transmission system to a variety of extreme weather conditions, such as blizzards, ice storms, and lightning.

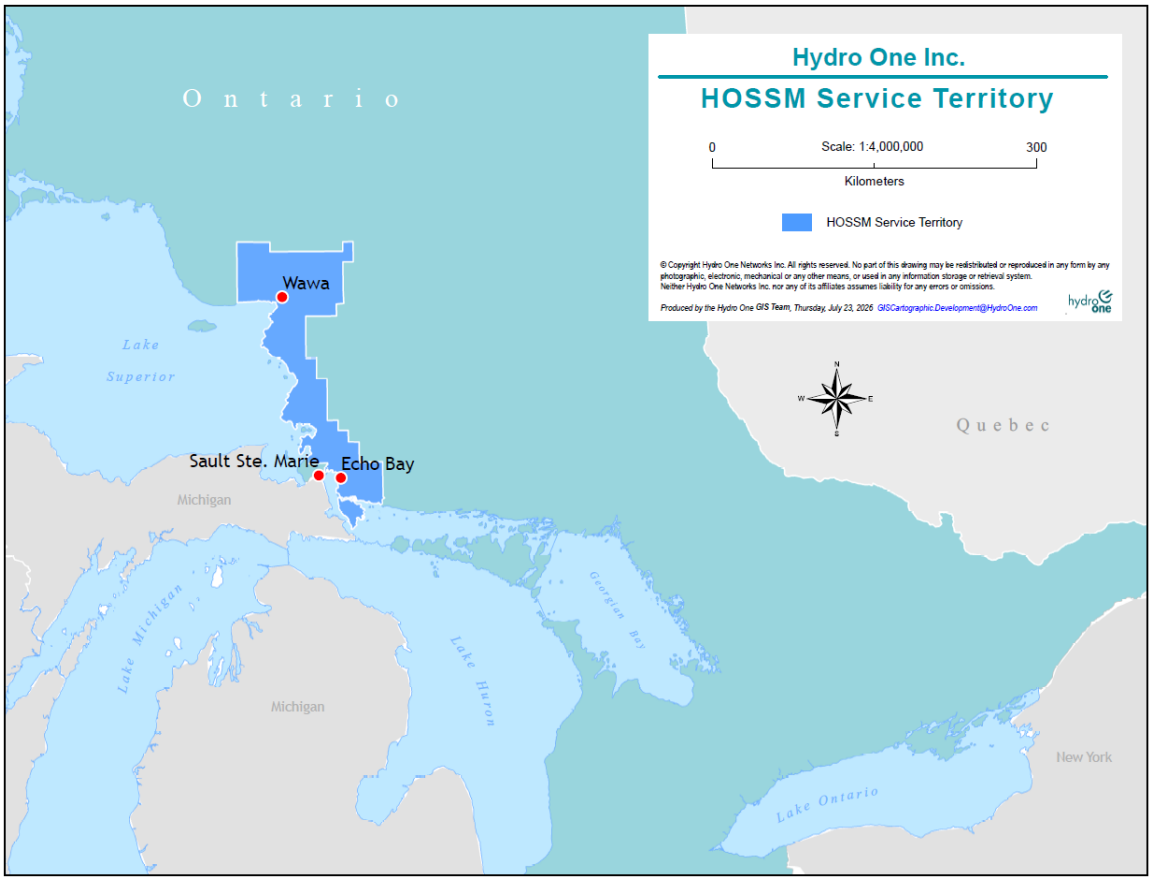

Figure 1: HOSSM Transmission System

2.10.3 TRANSMISSION ASSETS

HOSSM's transmission system consists of transmission lines and transmission stations operated at primarily 230kV, 115kV and 44kV[2]. The transmission system is controlled from Hydro One's centralized control centre, or back-up centre when required, to support reliable operation of the system.

[2] As set out in Schedule 1 of HOSSM's Transmission Licence, its system includes 11 circuit-km of 44 kV lines and associated equipment which have been deemed by the OEB as serving transmission function under Section 84 of the *Ontario Energy Board Act, 1998*.

HOSSM's key transmission system-related assets are presented in Table below. HOSSM's assets are like those installed on Hydro One's transmission system, and are operated, maintained and replaced in accordance with the same lifecycle strategies. Detailed information on HOSSM's assets (demographic, condition and performance information) and lifecycle strategies are discussed in TSP Section 2.2.

Table 1 - HOSSM's Key Transmission System Assets

System Assets	Total
Length of Overhead Transmission Lines (Total Circuit km)	554
Length of Underground Transmission Cables (Total Circuit km)	0
Transmission Stations (Total Number)	15
Installed Transformer Nameplate Capacity (MVA)	1192

2.10.4 BENCHMARKING AND OTHER STUDIES

Hydro One has conducted benchmarking and other studies as discussed in TSP Section 2.3. As discussed in section 2.10.11 below, HOSSM's capital projects are planned and executed using Hydro One's transmission capital delivery process, which has been independently reviewed and compared against the processes of industry peers by E-Source Inc. (see TSP Section 2.3, Attachment 1).

Furthermore, HOSSM has completed transmission total cost benchmarking, which indicates that its transmission costs have been below benchmark expectations over the last decade.[3] These results demonstrate that HOSSM has maintained efficient cost performance while continuing to deliver safe and reliable service.

2.10.5 TRANSMISSION SYSTEM RELIABILITY

HOSSM's transmission system reliability is measured from the perspectives of both delivery point and equipment on the same basis as Hydro One's transmission system. HOSSM's system reliability is discussed in TSP Section 2.4.

[3] Exhibit A-04-01 Attachment 1, Section 4.5.

2.10.6 PERFORMANCE MEASUREMENT AND OUTCOMES

The HOSSM scorecard is aligned with the OEB's Renewed Regulatory Framework (RRF) and is substantially aligned with Hydro One's transmission scorecard (discussed in TSP Section 2.5). Since Hydro One has operationally integrated HOSSM, several HOSSM measures are now consolidated within Hydro One's Transmission scorecard.

The HOSSM Scorecard, including actual performance for the 2019-2025 period, and proposed targets for the forecast period, are provided in Attachment 3 and Service and Reliability indicators are provided in Attachment 4.

2.10.7 OTHER CAPITAL PLANNING FACTORS AND CONSIDERATIONS

This section highlights the planning factors and considerations that shaped, informed, and influenced the development of HOSSM's System Plan in addition to asset needs (Section 2.10.3 herein and TSP Section 2.2), benchmarking (Section 2.10.4 herein and TSP Section 2.3) and system reliability (Section 2.10.5 herein and TSP Section 2.4). These additional factors are consistent with the principles and requirements of the RRF, including customer needs and preferences, and statutory and regulatory requirements.

Because HOSSM is operationally integrated with Hydro One, the Other Capital Planning Factors and Considerations discussed in TSP Section 2.6 were considered in developing the HOSSM System Plan. The factors relevant to HOSSM are summarized below.

2.10.7.1 CUSTOMER ENGAGEMENT

Hydro One undertakes a range of customer engagement activities to inform its capital planning processes, including a formal customer engagement survey that directly supports the development of the Transmission System Plan (TSP), as described in SPF Section 1.6.

These engagement activities provide insight into the outcomes customers value as well as their preferences regarding the level, mix, and pacing of transmission investments. This section explains how customer engagement results were reflected in the development of HOSSM's System Plan.

Customer engagement was undertaken in two stages. The initial stage occurred in mid-to-late 2024. It was conducted to identify customer priorities and outcome preferences in advance of detailed planning. The second stage, in late 2025, sought customer feedback on the draft investment plans, including their views on specific investment trade-offs. This sequencing allowed customer input to inform the development of candidate investments and subsequent refinement of the proposed plans.

HOSSM's proposed 2027-2032 Investment Plan was shaped by customer input, with investments reflecting customer feedback from the customer engagement study, as summarized in Table 2.

Table 2 - Reflection of Customer Feedback in the HOSSM System Plan

Objective	Customer Feedback	How it Appears in the Plan
Transmission Renewal	Maintain the current level of transmission station and cable health by replacing the highest-risk assets and managing failure risk over time.	• Address transformers and/or breakers at 6 stations (T-SR-03)
Transmission Stewardship	Lower the risk of equipment failure and severe weather through balanced investment in line renewal, structural asset stewardship, vegetation management, and system monitoring.	• Replace and refurbish wood poles (T-SR-04). • Carry out proactive vegetation management (E-02-06)

2.10.7.2 REGIONAL PLANNING NEEDS

As discussed in SPF Section 1.2, regional planning addresses supply and reliability needs at the regional and local level, including the facilities that connect and deliver power to groups of load stations within an area or region.

As the lead transmitter in the East Lake Superior region, HOSSM carries out regional planning considering its 115kV and 230kV system, which supplies various parts of the province. At some system boundaries, regional planning may interface with bulk system planning and distribution system planning. This can affect the alternatives considered to

address specific local or regional needs. HOSSM has no investments identified through the regional planning process over the 2027-2032 period.

2.10.7.3 BULK SYSTEM PLANNING

HOSSM considers bulk system planning issued by the Independent Electricity System Operator (IESO) as part of the overall transmission planning context. These bulk system plans provide information on broader system needs and long-term network development across all regions.

HOSSM used the best information available to develop capital expenditure and in-service addition (ISA) forecasts. In doing so, HOSSM has considered recent IESO bulk-planning developments, including the 2022 Need for Northeast Bulk System Reinforcements report which identified the North Shore Link investment discussed in section 2.10.9.3.3 below and TSP Section 2.12, T-SS-11.

The IESO, through its ongoing planning engagements, continues to assess needs across the province. Hydro One anticipates that the IESO will publish new Bulk System Studies and Integrated Regional Resource Plans in 2026 and 2027 (during this Application's proceeding) and more during the 2028-2032 period that may identify further mandatory investments not currently reflected in the investment plan. In July 2026, the IESO published an Integrated Regional Resource Plan for the East Lake Superior region. New investments arising from this report will be managed as described in the paragraph below.

In respect of both Regional Planning and Bulk System Planning, where HOSSM receives a request or direction from a government authority to develop or construct new investments after the investment plan was developed or must carry out investments as a result of Hydro One receiving a request or direction from a government authority to undertake such investments, HOSSM will update the investment plan where possible during this Application's proceeding. Following the OEB's Decision, the impact of new mandatory investments will be recorded in the Externally Driven Transmission Projects Variance Account as discussed in Exhibit G-01-04 Section 3.0.

2.10.7.4 THIRD-PARTY DIRECTED INVESTMENTS

Pursuant to its statutory and regulatory obligations under the *Electricity Transmission Licence, Transmission System Code*, *Public Service Works on Highways Act*, *1990,* as well as other authorities, HOSSM is required to connect customer facilities to its transmission system upon request; relocate its assets upon request from municipal and provincial governments and agencies to support transit expansion and road works; undertake investments necessary to expand or reinforce the Ontario transmission system consistent with IESO directions; and, where applicable advance transmission investments arising from provincial energy policy initiatives, including projects identified as priority transmission projects through an Order in Council.

As a result, HOSSM's System Plan includes investments required to satisfy its statutory and regulatory obligations including system expansion and reinforcement.

2.10.7.5 MAINTAINING A RELIABLE AND RESILIENT GRID

Under the scope of services provided to HOSSM by Hydro One, the same reliability and resilience considerations are applied to HOSSM assets. This includes incorporating updated engineering and design standards, applicable mandatory standards and industry best practices, and consideration of future climate stressors when assets are planned, designed, renewed and maintained. Accordingly, HOSSM investments reflect measures such as appropriate equipment ratings, hardened designs, restoration capabilities, and consideration of flood, stormwater and other climate-related risks to support long-term reliability and resilience.

2.10.7.6 ENVIRONMENTAL STEWARDSHIP

Under the scope of services provided to HOSSM by Hydro One, the same planning, engineering, asset management, vegetation management, and emergency preparedness practices are generally applied to HOSSM work, where relevant. To that extent, HOSSM benefits from climate-related considerations that support asset performance, system resilience, restoration capability, and operational risk management. Where applicable, HOSSM also benefits from operational and maintenance practices that support

greenhouse gas mitigation, including SF_6 leak reduction and the management of gas-insulated equipment.

2.10.7.7 OTHER REGULATORY REQUIREMENTS AND CONSIDERATIONS

Under the scope of services provided to HOSSM by Hydro One, the same planning and execution processes are generally applied to HOSSM work, where relevant. Accordingly, the same applicable regulatory requirements, standards, and considerations - including those relating to safety, reliability, environmental and noise mitigation, and cyber security - are incorporated into HOSSM's planning, design, execution, operation, and maintenance activities. This ensures that HOSSM work is planned and delivered in a manner consistent with Hydro One's compliance obligations and requirements for safe and reliable operation.

2.10.7.8 EFFICIENCIES

HOSSM's capital and OM&A work is performed or coordinated by Hydro One. This arrangement enables HOSSM to maintain low overhead and access specialized, flexible resources as needed, while benefiting from standardized business processes delivered by Hydro One.

2.10.8 INVESTMENT PLANNING PROCESS

HOSSM's investments are identified, evaluated, prioritized, and paced in accordance with Hydro One's investment planning process, discussed in TSP Section 2.7. Hydro One's integrated planning framework, known as the System Planning Process, is comprised of asset management and investment planning processes that provide a comprehensive approach for managing HOSSM's asset base and prudently identifying and prioritizing its investments.

HOSSM's System Plan supports the objective of maintaining long-term system reliability through the replacement of poor condition assets through System Renewal and reinforcement and expansion of facilities through System Service investments.

2.10.9 CAPITAL EXPENDITURES AND TRENDS

This section provides an overview of HOSSM's 2027-2032 capital expenditure plan and the material investments being proposed in HOSSM's System Plan. A summary of net capital expenditures for HOSSM is provided in Table 3 below.

Table 3 - HOSSM - Forecast Capital Expenditures ($M)[4]

OEB Investment Category	Forecast Period						% of Portfolio
	2027	2028	2029	2030	2031	2032	
System Access	2.2	0.0	0.0	0.0	0.0	0.0	1
System Renewal	19.2	35.2	20.7	21.8	22.3	13.4	69
System Service	18.3	29.4	9.2	0.3	0.0	0.0	30
General Plant	0.0	0.0	0.0	0.0	0.0	0.0	0
Total	**39.6**	**64.6**	**29.9**	**22.1**	**22.3**	**13.4**	**100**
System OM&A[5]	**10.6**	**10.9**	**-**	**-**	**-**	**-**	**-**

Over the 2027-2032 period, HOSSM plans to invest an average of $32.0M per year in Transmission capital, totaling $192.0M. This plan represents the level of investment required to maintain a reliable and resilient grid and meet Ontario's growing demand.

System Access investments account for 1% of the 2027-2032 HOSSM capital plan. These investments are non-discretionary investments that facilitate new load and generation customer connections and address transmission asset modifications to accommodate third party requests. HOSSM is required to provide transmission access when requested pursuant to the terms of its Transmitter License and the Transmission System Code. Over the forecast period, HOSSM expects no new customer connections and minimal expenditures in 2027 to complete an ongoing customer connection investment. HOSSM's System Access investments are discussed in Section 2.10.9.3.1 below.

[4] Figures presented in the tables may not sum to the totals shown due to rounding.
[5] System OM&A reflects total Operations, Maintenance and Administration expenses. Further information is provided in Exhibit E-02-06. 2029 - 2032 is determined based on the escalation factor identified in Exhibit A-04-02.

System Renewal investments account for 69% of HOSSM's 2027-2032 capital plan. These investments help manage and mitigate risks stemming from assets that are in poor condition (as indicated by condition assessments), have inadequate performance, are functionally obsolete, or have failed. Over the forecast period, HOSSM expects to increase annual System Renewal expenditures by 39% relative to the 2016-2026 period. HOSSM's System Renewal investments are discussed in Section 2.10.9.3.2 below.

System Service investments account for 30% of HOSSM's 2027-2032 capital plan. These investments are non-discretionary investments identified in IESO bulk system studies, regional planning processes, and government-directed transmission expansion initiatives that identify specific transmission reinforcements required to maintain reliability, ensure local supply adequacy, accommodate forecast load growth, and enable new generation resources. Over the forecast period, HOSSM is carrying out a 230kV switchyard expansion at Third Line TS to accommodate the new double circuits for the Mississagi x Third Line Reinforcement project, also known as the North Shore Link (TSP Section 2.12, T-SS-11). HOSSM's System Service investments are discussed in Section 2.10.9.3.3 below.

Over the 2027-2032 period, HOSSM does not have any planned General Plant investments. Generally, General Plant related expenditures are provided by Hydro One to HOSSM through services Hydro One carries out.[6] Should discrete General Plant investment arise, HOSSM will manage such investments within its funding envelope.

The latter part of HOSSM's deferred rebasing period has also been impacted by an unprecedented set of market forces that have resulted in sustained inflation, significantly increasing the cost of key electrical equipment and materials as discussed in SPF Section 1.8. Hydro One, on behalf of HOSSM, has continued to update project cost estimates to reflect market prices for materials and equipment, including power transformers, breakers, conductors, and other critical inputs. These updated costs now form the basis of the assumptions underlying HOSSM's 2027-2032 investment plans.

[6] For example: HOSSM does not purchase fleet vehicles, however vehicle related costs are included in the cost of services Hydro One delivers to HOSSM.

As outlined in Section 2.10.7.3, where HOSSM receives a request or direction from a government authority to develop or construct new investments after the investment plan was developed or must carry out investments as a result of Hydro One receiving a request or direction from a government authority to undertake such investments, HOSSM will update the investment plan where possible during this Application's proceeding. Following the OEB's Decision, the impact of new mandatory investments will be recorded in the Externally Driven Transmission Projects Variance Account as discussed in Exhibit G-01-04 Section 3.0.

2.10.9.1 OEB RRF OUTCOMES AND CUSTOMER PRIORITIES

As discussed in SPF Section 1.7 and TSP Section 2.7, the OEB's four Renewed Regulatory Framework (RRF) outcomes (Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance) are integrated into Hydro One's investment planning process, which is used to develop HOSSM's Investment Plan.

As discussed in Section 2.10.7.1, HOSSM's proposed 2027-2032 Investment Plan was shaped by customer input, with investments reflecting customer feedback from the customer engagement study, summarized in Table 2 above.

Customers expressed strong support for the replacement of aging and deteriorating transmission system assets to manage the risk of equipment failure and support growth across the province. These include the replacement of transmission station transformers and breakers. Customers also expressed strong support for investments to enhance the stewardship of the transmission system including reinforcing wood poles and accelerating the clearing of overgrown trees.

2.10.9.2 HOSSM INVESTMENT PLAN PRIORITIES

HOSSM's 2027-2032 investment plan is intended to achieve two investment priorities:

i. Maintain a Reliable and Resilient Grid; and
ii. Meet Ontario's Growing Demand for Electricity.

These priorities reflect HOSSM's investment needs and provide the framework used throughout this sub-section to explain the rationale and expected outcomes of the proposed capital plan.

MAINTAINING A RELIABLE AND RESILIENT GRID

A safe, reliable and resilient electricity system requires timely renewal of aging and deteriorated infrastructure, alongside sustained investment to address increasing asset risk. This priority focuses on restoring asset health and stabilizing overall system performance to reduce outage exposure risk and strengthen operating flexibility.

These investments incorporate current industry standards, enabling infrastructure that is resilient and aligned with the System Renewal investment category. This approach emphasizes system redundancy, and modern equipment designs to respond to changing conditions and maintain service continuity during severe weather events.

MEETING ONTARIO'S GROWING DEMAND FOR ELECTRICITY

Meeting Ontario's plans for electrification and growth is a core priority. This priority includes System Access and System Service projects that enable HOSSM to connect new and modified customer load, respond to external drivers, accommodate increasing demand and electrification, and address capacity constraints. Investments planned under this priority are intended to ensure that HOSSM remains able to connect customers, respond to demand growth, support externally driven infrastructure requirements, address emerging capacity needs, and maintain system reliability and power quality across its service territory. These investments are aligned with the System Access and System Service investment categories.

HOSSM's investment plan is organized around the same investment priorities as Hydro One. Each priority, and key corresponding investments (by ISD), is described in TSP Section 2.8.3. Table 4 below summarizes HOSSM's overall capital expenditures by investment priorities.

Table 4 - HOSSM's Forecast Capital Expenditures by Investment Priority

Investment Priority	Forecasting Period						% of Portfolio
	2027	2028	2029	2030	2031	2032	
Maintaining a Reliable and Resilient Grid	19.2	35.2	20.7	21.8	22.3	13.4	**69%**
Meet Ontario's Growing Demand	20.4	29.4	9.2	0.3	0.0	0.0	**31%**
Total	**39.6**	**64.6**	**29.9**	**22.1**	**22.3**	**13.4**	**100%**

2.10.9.3 FORECAST CAPITAL EXPENDITURES AND TREND ANALYSIS

Table 5 - HOSSM – Historical and Forecast Capital Expenditures ($M)

OEB Category	Historical Actual										Bridge Forecast	Forecast Period					
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
System Access	0.0	0.0	0.0	-0.3	0.3	1.2	2.2	7.2	32.3	21.4	12.1	2.2	0.0	0.0	0.0	0.0	0.0
System Renewal	4.3	5.8	5.1	2.5	3.6	7.2	6.4	21.0	37.5	51.2	30.6	19.2	35.2	20.7	21.8	22.3	13.4
System Service	3.1	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.3	29.4	9.2	0.3	0.0	0.0
General Plant	2.1	4.3	0.6	0.6	0.0	3.3	1.0	1.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**9.4**	**13.5**	**5.7**	**2.7**	**3.9**	**11.6**	**9.6**	**29.8**	**70.0**	**72.6**	**42.7**	**39.6**	**64.6**	**29.9**	**22.1**	**22.3**	**13.4**

2.10.9.3.1 SYSTEM ACCESS

System Access investments are non-discretionary investments that facilitate new load and generation customer connections and address transmission asset modifications to accommodate third-party requests. HOSSM is required to provide transmission access when requested pursuant to the terms of the *Electricity Act, 1998*, its Transmission License and the Transmission System Code.

Over the 2016-2026 period, HOSSM carried out several System Access investments discussed in Section 2.10.10.1 below. The most material investment required HOSSM to connect a new 230 kV double circuit transmission line from PUC (Transmission) LP's (PUC) transformer station to HOSSM's Third Line TS (TSP Section 2.12, T-SA-11). PUC's new transmission line will supply the local steel manufacturer's new Electric Arc Furnaces.

Over the forecast period, HOSSM expects no new customer connections based on historical system access requests and anticipated growth. The minimal expenditures in 2027 are needed to complete the ongoing customer connection investment at Third Line TS (TSP Section 2.12, T-SA-11), discussed above.

The following tables summarize HOSSM's historical and forecast System Access capital expenditures as well as material investments that are further discussed in TSP Section 2.12 within the referenced Investment Summary Document (ISD).

Table 6 - HOSSM - Historical System Access Capital Expenditures ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Access	0.0	0.0	0.0	-0.3	0.3	1.2	2.2	7.2	32.3	21.4	12.1

Table 7 - HOSSM - Forecast System Access Capital Expenditures ($M)

OEB Category	Forecast Period					
	2027	2028	2029	2030	2031	2032
System Access	2.2	0.0	0.0	0.0	0.0	0.0

Table 8 - HOSSM – System Access Material Investments

ISD	Investment Title	2027	2028	2029	2030	2031	2032
T-SA-11	HOSSM Third Line TS PUC 230kV Connections	2.2	0.0	0.0	0.0	0.0	0.0

2.10.9.3.2 SYSTEM RENEWAL

System Renewal investments help manage and mitigate risks stemming from assets that are in poor condition (as indicated by condition assessments), have inadequate performance, are functionally obsolete, or have failed.

Over the 2016-2026 period, HOSSM carried out several System Renewal investments with notable station investments including the transformer replacement at Third Line TS (TSP Section 2.12, T-SR-01) and component replacements (including a transformer) at Batchewana TS (TSP Section 2.12, T-SR-Other), and lines investments related to the refurbishment of the Sault #3 transmission line (TSP Section 2.12, T-SR-13), discussed in Section 2.10.10.2 below.

Over the forecast period, HOSSM expects to increase annual System Renewal expenditures by 39% relative to the 2016-2026 period to address assets that are in poor condition (as indicated by condition assessments), have inadequate performance, are functionally obsolete, or have failed.

HOSSM has planned several Connection Station renewal investments (TSP Section 2.12, T-SR-03) including the replacement of the poor condition and obsolete metalclad switchgear at Clergue TS, Watson TS, and Patrick St TS and the replacement of the poor condition transformer and switches at Goulais TS along with a station reconfiguration that benefits connected customers. These four investments account for $88.0M, or 66% of HOSSM's forecast System Renewal expenditures over the 2027-2032 period.

HOSSM has planned for emergency replacement of transmission station assets that have failed or are at an imminent risk of failure and the procurement of strategic spare inventory through its Transmission Station Demand and Spares program (TSP Section 2.12, T-SR-09). The forecasted number of failed units expected to be replaced under demand is expected to be consistent with the five-year historical average. This investment is needed to mitigate safety, system reliability, and environmental risks resulting from failure. This program accounts for $6.2M, or 5% of HOSSM's forecast System Renewal expenditures over the 2027-2032 period.

The majority of HOSSM's transmission lines are installed on wood pole structures. Currently, 12% of these structures are in poor condition. Over the forecast period, HOSSM plans to replace 10% of the wood structure population through its Wood Pole Structure Replacement program (TSP Section 2.12, T-SR-04). This program accounts for $23.4M or 18% of HOSSM's forecast System Renewal expenditures over the 2027-2032 period.

HOSSM has included funding to address transmission lines assets that have either failed or are at imminent risk of failure through its Transmission Line Emergency Restoration program (TSP Section 2.12, T-SR-15). This program ensures timely intervention to maintain system reliability and minimize service disruptions. This program accounts for $5.7M, or 4% of HOSSM's forecast System Renewal expenditures over the 2027-2032 period.

Over the forecast period, HOSSM has budgeted approximately $50K per year in respect of Lines Trouble Call and Storm Damage Response (DSP Section 3.11, D-SR-05), and Pole Sustainment (DSP Section 3.11, D-SR-07) programs for its 11 circuit-kms of 44 kV lines and associated equipment which have been deemed by the OEB as serving a transmission function.

The following tables summarize HOSSM's historical and forecast System Renewal capital expenditures as well as material investments that are further discussed in TSP Section 2.12 within the referenced Investment Summary Document (ISD).

Table 9 - HOSSM - Historical System Renewal Capital Expenditures ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Renewal	4.3	5.8	5.1	2.5	3.6	7.2	6.4	21.0	37.5	51.2	30.6

Table 10 - HOSSM - Forecast System Renewal Capital Expenditures ($M)

OEB Category	Forecast Period					
	2027	2028	2029	2030	2031	2032
System Renewal	19.2	35.2	20.7	21.8	22.3	13.4

Table 11 - HOSSM – Material System Renewal Investments

ISD	Investment Title	2027	2028	2029	2030	2031	2032
T-SR-03	Transmission Station Renewal - Connection Stations	15.5	28.8	14.3	15.2	15.6	6.6
T-SR-04	Wood Pole Structure Replacements	0.8	4.3	4.4	4.5	4.6	4.7
T-SR-09	Transmission Station Demand and Spares	1.1	1.0	1.0	1.0	1.0	1.1
T-SR-15	Transmission Line Emergency Restoration	1.8	0.7	0.8	0.8	0.8	0.8
Total System Renewal		**19.2**	**35.2**	**20.7**	**21.8**	**22.3**	**13.4**

2.10.9.3.3 SYSTEM SERVICE

System Service investments are non-discretionary investments identified in IESO bulk system studies, regional planning processes, and government-directed transmission expansion initiatives that identify specific transmission reinforcements required to maintain reliability, ensure local supply adequacy, accommodate forecast load growth, and enable new generation resources.

Over the 2016-2026 period, HOSSM carried out several System Service investments discussed in Section 2.10.10.3 below. The most material investment required HOSSM to complete upgrades at Anjigami TS and Watson TS. There have been no System Service expenditures since 2018.

Over the forecast period, HOSSM is carrying out a 230kV switchyard expansion at Third Line TS to accommodate new double circuits for the Mississagi x Third Line Reinforcement project, also known as the North Shore Link (TSP Section 2.12, T-SS-11). This project was recommended in the IESO's Northeast Bulk Plan and the Minister of Energy and Mines issued an Order in Council (1531/2023) designating the North Shore Link a priority project and an Order in Council (1532/2023) directing Hydro One to develop the project. Following the Order in Council in 2023, Hydro One Transmission initiated development work, as detailed in TSP Section 2.12, T-SS-11.03, with HOSSM's component of the station work scheduled to proceed from 2027 to 2029.

The following tables summarize HOSSM's historical and forecast System Service capital expenditures as well as material investments that are further discussed in TSP Section 2.12 within the referenced Investment Summary Document (ISD).

Table 12 - HOSSM - Historical System Service Capital Expenditures ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Service	3.1	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 13 - HOSSM – Forecast System Service Capital Expenditures ($M)

OEB Category	Forecast Period					
	2027	2028	2029	2030	2031	2032
System Service	18.3	29.4	9.2	0.3	0.0	0.0

Table 14 - HOSSM – Material System Service Investments

ISD	Investment Title	2027	2028	2029	2030	2031	2032
T-SS-11	North Shore Link: Missi x Third Line	18.3	29.4	9.2	0.3	0.0	0.0

2.10.9.3.4 GENERAL PLANT

Generally, General Plant related expenditures are provided by Hydro One to HOSSM through services Hydro One carries out.[7] However, HOSSM may undertake discrete General Plant investments that fall outside the normal delivery of these services.

Over the 2016-2026 period, HOSSM carried out several discrete investments related to facility repairs and physical security, discussed in Section 2.10.10.4 below.

Over the 2027-2032 period, HOSSM does not have any planned General Plant investments. Should discrete General Plant investment arise, HOSSM will manage such investments within its funding envelope.

The following tables summarize HOSSM's historical and forecast General Plant capital expenditures.

Table 15 - HOSSM - Historical General Plant Capital Expenditures ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
General Plant	2.1	4.3	0.6	0.6	0.0	3.3	1.0	1.6	0.1	0.0	0.0

[7] For example: HOSSM does not purchase fleet vehicles, however vehicle related costs are included in the cost of services Hydro One delivers to HOSSM.

Table 16 - HOSSM – Forecast General Plant Capital Expenditures ($M)

OEB Category	Forecast Period					
	2027	2028	2029	2030	2031	2032
General Plant	0.0	0.0	0.0	0.0	0.0	0.0

2.10.9.4 IMPACT OF CAPITAL INVESTMENT ON OPERATIONS, MAINTENANCE AND ADMINISTRATION SPENDING

HOSSM's investments are identified, evaluated, prioritized, and paced in accordance with Hydro One's investment planning process. Any impact on total OM&A must be considered in the context of the level and type of capital work and the fleet of assets that it is intended to renew. Installing new equipment does not yield lower maintenance costs immediately; it takes time for those reductions to materialize. Furthermore, new equipment still requires routine preventive maintenance, manufacturer-recommended inspections, and warranty-related maintenance, particularly during the first few years of operation. As an example, both new and old transmission lines require helicopter and foot patrols at the same frequency.

Similarly, while newer equipment may reduce unplanned corrective maintenance, there are still costs due to external factors such as severe weather, vehicle collisions, and wildlife impacts. Given the small portion of assets planned for replacement in the 2027-2032 period, maintenance savings resulting from the planned capital investments are negligible in relation to the maintenance funding required to maintain the remaining pool of aging assets.

2.10.10 HISTORICAL CAPITAL EXPENDITURES VARIANCES

In 2016, Hydro One Inc. received OEB approval to acquire Great Lakes Power Transmission LP and in that application provided Great Lakes Power Transmission LP's forecast capital expenditures without the transaction proceeding, as shown in Table 17 below.[8] Since the transaction was approved in 2016, HOSSM has been in a deferred rebasing period.

[8] EB-2016-0050, Exhibit A-02-01 – Table 2.

Over the 2016-2026 period, HOSSM's capital expenditures have predominantly been driven by a limited number of material projects, each discussed under the relevant OEB investment category below. During this period, HOSSM reprioritized its investments, particularly in System Renewal, to allow it to accommodate new mandatory customer connection work in System Access and an unprecedented set of market forces that arose in the latter part of HOSSM's deferred rebasing period which has resulted in sustained inflation, significantly increasing the cost of key electrical equipment and materials as discussed in SPF Section 1.8.

Over the deferred rebasing period, HOSSM's cumulative actual and forecast capital expenditures are approximately $78.8M higher than the MAADs Status Quo Forecast scenario (i.e., "without transaction") compared to the forecast savings of $17.1M for the MAADs Base scenario (i.e., base "with transaction") vs. Status Quo Forecast scenario, as shown in Table 17. In the first six years of operational integration, HOSSM reduced the General Plant category due to synergies, and overall capital expenditures were below the MAADs Status Quo Forecast scenario. However, these savings were offset in the last four years by material and mandatory customer driven investments in System Access of $64.9M at Third Line TS (TSP Section 2.12, T-SA-11) and large System Renewal expenditures of $36.7M at Third Line TS (TSP Section 2.12, T-SR-01) which were being undertaken together for efficiency.

As discussed in Section 2.10.4, HOSSM has completed transmission total cost benchmarking, which indicates that its transmission costs have been below benchmark expectations over the last decade. These results demonstrate that HOSSM has maintained efficient cost performance while continuing to deliver safe and reliable service.

Table 17 - HOSSM - Historical and Bridge Capital Expenditure Summary ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
System Access	0.0	0.0	0.0	-0.3	0.3	1.2	2.2	7.2	32.3	21.4	12.1
System Renewal	4.3	5.8	5.1	2.5	3.6	7.2	6.4	21.0	37.5	51.2	30.6
System Service	3.1	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant	2.1	4.3	0.6	0.6	0.0	3.3	1.0	1.6	0.1	0.0	0.0
Total	**9.4**	**13.5**	**5.7**	**2.7**	**3.9**	**11.6**	**9.6**	**29.8**	**70.0**	**72.6**	**42.7**
MAADS Status Quo Forecast[9]	n/a	19.4	16.2	17.6	18.6	17.5	20.6	19.9	18.3	17.4	17.8
Status Quo Savings from Acquisition	**n/a**	**5.9**	**10.5**	**14.9**	**14.7**	**5.9**	**11.0**	**-9.9**	**-51.7**	**-55.2**	**-24.9**
MAADS Base Forecast[10]	n/a	**19.4**	**16.2**	**14.7**	**14.1**	**15.3**	**17.6**	**16.9**	**17.8**	**16.9**	**17.3**
Base vs Status Quo Savings	**n/a**	**0.0**	**0.0**	**2.9**	**4.5**	**2.2**	**3.0**	**3.0**	**0.5**	**0.5**	**0.5**

2.10.10.1 SYSTEM ACCESS

Over the 2016-2026 period, HOSSM carried out several System Access investments. The most material investment was a request to connect a new 10km 230 kV double circuit transmission line from PUC's transformer station to HOSSM's Third Line TS (TSP Section 2.12, T-SA-11). This investment, with expenditures of $64.9M over the historical period, requires HOSSM to complete material station reconfiguration work at Third Line TS including new breakers, switches, yard expansion and a new protection and control building. PUC's new transmission line will supply the local steel manufacturer's new Electric Arc Furnaces.

HOSSM completed station upgrades of $2.9M over the historical period at Echo River TS, installing a spare transformer to provide contingency support in the event of a failure of the single existing transformer, and included the replacement of poor condition breaker within the project. Work was also undertaken to construct a new line tap and make

[9] EB-2016-0050, Exhibit A-02-01 – Table 2.
[10] EB-2016-0050, Exhibit A-02-01 – Table 3.

protection modifications at Hollingsworth TS to accommodate the expansion needs of a mine; and make protection modifications and upgrade grounding at several stations to accommodate the connections associated with a local steel manufacturer ($4.2M).

The table below presents historical capital expenditures for System Access.

Table 18 - HOSSM - Historical and Bridge System Access ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Access	0.0	0.0	0.0	-0.3	0.3	1.2	2.2	7.2	32.3	21.4	12.1

2.10.10.2 SYSTEM RENEWAL

Over the 2016-2026 period, HOSSM carried out several System Renewal investments with notable station investments including the transformer replacement at Third Line TS (TSP Section 2.12, T-SR-01) and component replacements (including a transformer) at Batchewana TS (TSP Section 2.12, T-SR-Other), and lines investments related to the refurbishment of the Sault #3 transmission line (TSP Section 2.12, T-SR-13).

Third Line TS, located in the City of Sault Ste. Marie, serves the majority of the city's residential and industrial load. This investment, with expenditures of $36.7M over the historical period, replaces the T2 autotransformer at Third Line TS, driven by its deteriorating condition and the risk that its failure would subject the station to single contingency through T1, the loss of which would result in extensive service outages in the Sault Ste. Marie area. HOSSM is also completing protection system upgrades at the station (TSP Section 2.12, T-SR-01).

The Sault #3 transmission line (TSP Section 2.12, T-SR-13) investment, with expenditures of $68.8M over the historical period, involves the refurbishment and capacity increase of the 115kV circuit between Third Line TS and Mackay TS, connecting generation from the Wawa area to the Sault Ste. Marie area. The original transmission line was placed in service in 1929 and is approximately 90.5km in length. This project is a significant

component of the overall System Renewal expenditures during the historical period and is expected to support system reliability and accommodate future load requirements once completed, in 2026.

Over the 2016-2026 period, HOSSM has connection station renewal work (TSP Section 2.12, T-SR-03) of $6.9M to upgrade Goulais TS transformers and other components, and $4.8M to replace Clergue TS metalclad switchgear due to emergent needs. HOSSM is also investing $15.5M in component replacements (including a transformer) at Batchewana TS (TSP Section 2.12, T-SR-Other) and invested $2.3M in protection replacements at Watson TS.

Over the 2016-2026 period, HOSSM is expected to invest $9.6M to replace poor condition wood poles (TSP Section 2.12, T-SR-04) and $4.6M to replace wood poles on P21G; $5.8M to address minor demand repairs (TSP Section 2.12, T-SR-09), and $8.6M for emergency transmission line replacements (TSP Section 2.12, T-SR-15). In addition, HOSSM completed $7.4M on structure repairs and replacement, and invested $1.3M to replace T1 transformer at Mackay TS

To accommodate higher overall capital expenditures, several investments or programs were reprioritized including work in the Wood Pole Replacement program (TSP Section 2.12, T-SR-04), Northern Ave T1 Replacement, and the Watson TS Metalclad Replacement (both TSP Section 2.12, T-SR-03).

The table below presents historical capital expenditures for System Renewal.

Table 19 - HOSSM - Historical and Bridge System Renewal ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Renewal	4.3	5.8	5.1	2.5	3.6	7.2	6.4	21.0	37.5	51.2	30.6

2.10.10.3 SYSTEM SERVICE

Over the 2016-2026 period, HOSSM's completed System Service investments refurbishing Anjigami TS to upgrade aging and deteriorating station equipment to improve 44kV supply redundancy and reliability, and Watson TS T2 breaker and protection upgrades to improve reliability and safety. Since 2018, HOSSM has had no System Service expenditures.

The table below presents historical capital expenditures for System Service.

Table 20 - HOSSM - Historical and Bridge System Service ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Service	3.1	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

2.10.10.4 GENERAL PLANT

Over the 2016-2026 period, General Plant expenditure was predominantly driven by, $3.7M for land rights in 2017 for future station expansion, $3.5M for the acquisition of the Sackville Work Centre and $1.0M for the subsequent roof replacement to address the failing and end-of-life roof system, $1.2M for SCADA integration, and $1.1M for Physical Access control work.

The table below presents historical capital expenditures for General Plant.

Table 21 - HOSSM - Historical and Bridge General Plant ($M)

OEB Category	Historical Actual										Bridge Forecast
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
General Plant	2.1	4.3	0.6	0.6	0.0	3.3	1.0	1.6	0.1	0.0	0.0

2.10.11 CAPITAL WORK EXECUTION

Since Hydro One has operationally integrated HOSSM, HOSSM's capital projects are planned and executed using Hydro One's transmission capital delivery process, which has

been independently reviewed and compared against the processes of industry peers by E-Source Inc. (see TSP Section 2.3, Attachment 1). Further information on Hydro One Transmission's capital delivery model can be found in TSP Section 2.11.

2.10.12 MATERIAL INVESTMENT SUMMARY DOCUMENTS

Investment Summary Documents (ISD) are attached to TSP Section 2.12. ISDs are provided where any proposed HOSSM capital expenditure exceeds the materiality threshold of $0.29M in a single year. HOSSM has no General Plant investments.

SECTION 2.10 – ATTACHMENT 1 – HOSSM DX CHAPTER 2 APPENDIX 2 – AA – CAPITAL PROJECTS FOR TRANSMISSION

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SECTION 2.10 – ATTACHMENT 2 – HOSSM DX CHAPTER 2 APPENDIX 2 – AB – CAPITAL EXPENDITURES SUMMARY FROM CHAPTER 5 CONSOLIDATED DISTRIBUTION SYSTEM PLAN FILING REQUIREMENTS

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SECTION 2.10 – ATTACHMENT 3 – HOSSM – PERFORMANCE MEASUREMENT AND OUTCOMES

1.0 INTRODUCTION

In 2016, Hydro One Inc. received OEB approval to acquire Great Lakes Power Transmission LP (which was subsequently renamed Hydro One Sault Ste. Marie (HOSSM)), as well as approval for a ten-year deferred rebasing period. Since October 1, 2018, HOSSM has been operationally integrated with Hydro One. However, HOSSM will remain financially and legally separate until such time that a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One. See Exhibit A-08-01 for further details.

In HOSSM's application for 2019 Transmission Revenue Requirement and related matters (EB-2018-0218), the OEB approved HOSSM's proposed scorecard with amendments.[1]

Since Hydro One operationally integrated HOSSM, several HOSSM scorecard measures have been consolidated within Hydro One's Transmission's scorecard metrics, with actuals for the current period and targets for the 2027-2032 period being presented on a combined basis.

HOSSM's scorecard, including actual performance for the 2019-2025 period relative to the 2019-2023 targets set out in EB-2018-0218, and proposed targets for the 2027-2032 period are provided in Figure 1 below. HOSSM does not have OEB approved targets for 2024-2026, as such, results are compared to the prior year actuals. The sections that follow discuss metric performance and indicate whether a HOSSM specific target has

[1] EB-2018-0218, Decision and Order, June 20, 2019, sec. 8 Performance Scorecard: 1) A separate MD&A section, 2) Actual values for each historical year and targets for 2020 and beyond for each measure (or an explanation why the data was not provided), 3) CDPP standards, and 4) T-SAIFI reliability metric divided into momentary and sustained outages. The scorecard must be filed with the OEB each year, starting in 2020 with 2019 results. The timing of that filing is expected to coincide with deadlines established for electricity distributors.

been established, or whether HOSSM is proposing to remove the metric from its scorecard as it will be reported within the Hydro One scorecard metric.

Unless otherwise noted, the definition and calculation of the HOSSM metrics are the same as those for Hydro One Transmission's metrics, discussed in TSP Section 2.5. As such, these details have been included below on an exception basis.

Performance Outcomes	Performance Categories	Measures	Performance								Targets[2]										
			2019	2020	2021	2022	2023	2024	2025	Trend	2019	2020	2021	2022	2023	2027	2028	2029	2030	2031	2032
Customer Focus	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	0%	6%	6%	6%	0%	0%	0%	▼	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Customer Satisfaction	Overall % Customer Satisfaction in Corporate Survey	Consolidated with Hydro One Tx Scorecard[3]																		
		Satisfaction with Outage Planning Procedures (% Satisfied)	Consolidated with Hydro One Tx Scorecard[3]																		
Operational Effectiveness	Safety	Lost Time Injuries or Illnesses	Consolidated with Hydro One Tx Scorecard[3]																		
	System Reliability	T-SAIFI-S (Avg # of sustained interruptions per DP)	0.33	0.83	0.5	1.22	0.83	1.22	0.83	▲	0.55	0.53	0.52	0.51	0.50	**0.79**	**0.79**	**0.78**	**0.78**	**0.78**	**0.77**
		T-SAIFI-M (Avg # of momentary interruptions per DP)	0	0	0	0	0	0	0	►	0.03	0.03	0.03	0.03	0.03	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**
		T-SAIDI (Average # Minutes of Power Interruptions per DP)	40.1	167.6	72.3	47.7	55.1	25.1	24.6	▼	45.6	44.7	43.8	42.9	42.1	44.9	44.7	44.5	44.4	44.2	44.0
		**System Unavailability (%)	0.01%	0.08%	0.34%	0.01%	0.55%	0.78%	0.79%	▲	-	-	-	-	-	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
		Unsupplied Energy (minutes)	30.7	23.8	31.2	16.5	32.7	7.1	10.3	▼	12.3	12.1	11.9	11.6	11.4	19.4	19.4	19.3	19.2	19.1	19.0
	Asset and Project Management	In-Service Additions (% of OEB approved plan)	425%	102%	115%	35%	148%	47%	104%	▼	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
		CapEx as % of OEB Approved Plan	30%	67%	82%	57%	71%	76%	103%	▲	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	5.89%	6.20%	8.40%	9.79%	18.47%	25.93%	22.93%	▲	4.83%	5.87%	5.65%	5.66%	4.93%	10.62 %	14.69 %	-	-	-	-
		Sustainment Capital per Gross Fixed Asset Value (%)	1.23%	1.88%	4.03%	5.29%	12.15%	11.59%	14.33%	▲	1.93%	2.90%	2.77%	2.84%	2.27%	Removed					
		OM&A per Gross Fixed Asset Value (%)	4.56%	4.16%	3.86%	3.65%	3.51%	3.23%	2.59%	▼	2.90%	2.97%	2.89%	2.81%	2.61%	2.23%	2.12%	-	-	-	-
Public Policy Responsiveness	Connection of Renewable Generation	* % On-time Completion of Renewables Connection Impact Assessments	None requested	None requested	None requested	None requested	None requested	None requested	None requested	►	100%	100%	100%	100%	100%	Removed					
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning Progress - % Deliverables met	Consolidated with Hydro One Tx Scorecard[3]																		
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	1.32	1.12	1.75	0.23	0.28	0.08	0.04	▼	-	-	-	-	-	-	-	-	-	-	-
		Leverage: Total Debt to Equity	0.86	0.85	0.76	0.68	0.61	0.55	0.51	▼	-	-	-	-	-	-	-	-	-	-	-
		Profitability: Regulatory Return on Equity (Deemed in Rates)	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	▼	-	-	-	-	-	-	-	-	-	-	-
		Profitability: Regulatory Return on Equity (Achieved)	10.56%	14.48%	16.57%	17.54%	19.45%	20.10%	17.07%	▲	-	-	-	-	-	-	-	-	-	-	-

Figure 1: HOSSM Scorecard and Targets

[2] Targets for 2018-2023 were established in EB-2018-0218; no targets for 2024-2026 were set. Targets for 2027-2032 are proposed within this Application.
[3] 2021-2025 results reported in TSP Section 2.5 on a consolidated basis. Prior 2019-2020 results may be found in EB-2021-0110, TSP Section 2.5.

Witness: Spencer Gill; Mark Brodie, Anthony Nava

The following sections discuss each of the measures shown in Figure 1 above. Unless otherwise noted, each measure follows the same definition and criteria as described in TSP Section 2.5 (TSP - Performance Measurement and Outcomes).

2.0 CUSTOMER FOCUS MEASURES

2.1 SERVICE QUALITY

CUSTOMER DELIVERY POINT PERFORMANCE, STANDARD OUTLIERS AS PER CENT OF TOTAL DELIVERY POINTS

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

The performance for 2020-2022 was higher than target due to one delivery point exceeding a group or individual threshold in each of those years. This resulted in a 6% impact due to the small number of HOSSM delivery points. For all other years the result was 0% which was in line with the target.

Table 1 - CDPPS Outliers as Percentage of Total Delivery Points (%)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	0%	0%	0%	0%	0%	N/A	N/A	
Actual	0%	6%	6%	6%	0%	0%	0%	▼

TARGETS

The OEB recently approved changes to the CDPP standards on November 27, 2025 in a letter to transmitters (EB-2021-0307). On March 1, 2026, as required by the OEB, Hydro One filed a revised CDPP Standards to reflect these changes. Once approved, HOSSM will provide an update to this metric reflecting the updated standards. This new standard will see CDPP Standards based on more recent data as was requested in the Decision and Order for HOSSM's application for 2019 Transmission Revenue Requirement (EB-2018-0218).

Over the 2027-2032 period, the HOSSM target for CDPPS Outliers as a percentage of Total Delivery Points is 0%.

Table 2 - CDPPS Outlier Targets (%)

	2027	2028	2029	2030	2031	2032
Target	0%	0%	0%	0%	0%	0%

2.2 CUSTOMER SATISFACTION

2.2.1 OVERALL CUSTOMER SATISFACTION IN CORPORATE SURVEY (PERCENT SATISFIED) (CONSOLIDATED WITH HYDRO ONE)

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Historical performance and future year targets for this metric are reported on a consolidated basis for Hydro One Transmission and HOSSM in TSP Section 2.5.

2.2.2 SATISFACTION WITH OUTAGE PLANNING PROCEDURES (PERCENT SATISFIED) (CONSOLIDATED WITH HYDRO ONE)

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Historical performance and future year targets for this metric are reported on a consolidated basis for Hydro One Transmission and HOSSM in TSP Section 2.5.

3.0 OPERATIONAL EFFECTIVENESS

3.1 SAFETY

3.1.1 LOST TIME INJURIES OR ILLNESS (CONSOLIDATED WITH HYDRO ONE)

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Historical performance and future year targets for this metric are reported on a consolidated basis for Hydro One Transmission and HOSSM in TSP Section 2.5.

3.2 SYSTEM RELIABILITY

3.2.1 T-SAIFI-S

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

In EB-2018-0218 the OEB ordered HOSSM to amend its scorecard and report the T-SAIFI reliability metric divided into momentary and sustained outages. The average number of sustained interruptions per Delivery Point in 2025 was 0.83, a decrease in the index value of 0.39 or about 32% compared to 2024, primarily due to fewer Equipment and Unknown caused interruptions.

HOSSM's average performance over the past five years (2021-2025) was 0.92, and the performance trend is rising (see Figure 2).

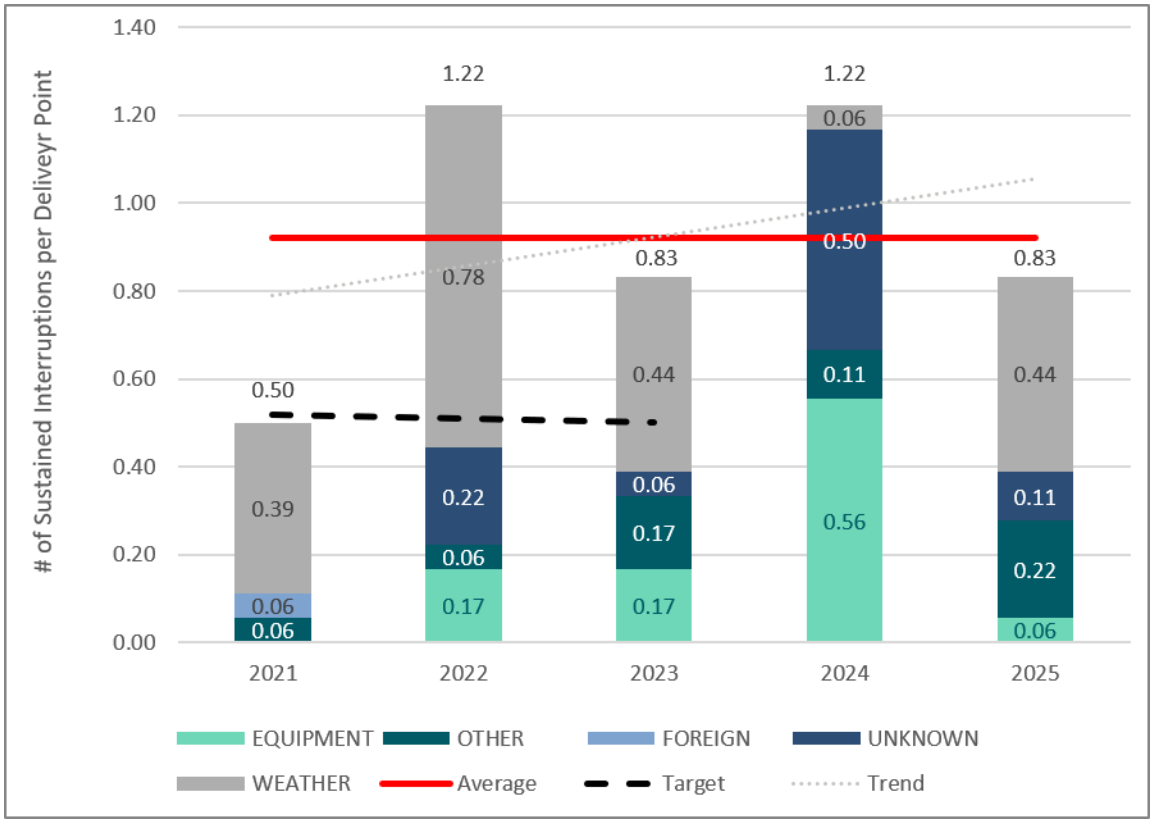

Figure 2: Transmission System Average Interruption Frequency Index – Sustained

TARGETS

Over the 2027-2032 period, HOSSM aims to improve T-SAIFI-S performance by 2% over 6 years to align with Hydro One's approach. Targets have been presented on the table below.

Table 3 - T-SAIFI-S Targets

	2027	2028	2029	2030	2031	2032
Target	0.79	0.79	0.78	0.78	0.78	0.77

3.2.2 T-SAIFI-M

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

In EB-2018-0218 the OEB ordered HOSSM to amend its scorecard and report the T-SAIFI reliability metric divided into momentary and sustained outages. The average number of momentary interruptions per Delivery Point in 2025 was 0, consistent with the result for the last five years.

HOSSM's average performance over the past five years (2021-2025) was 0 interruptions per Delivery Point, and the performance trend is flat (see Figure 3).

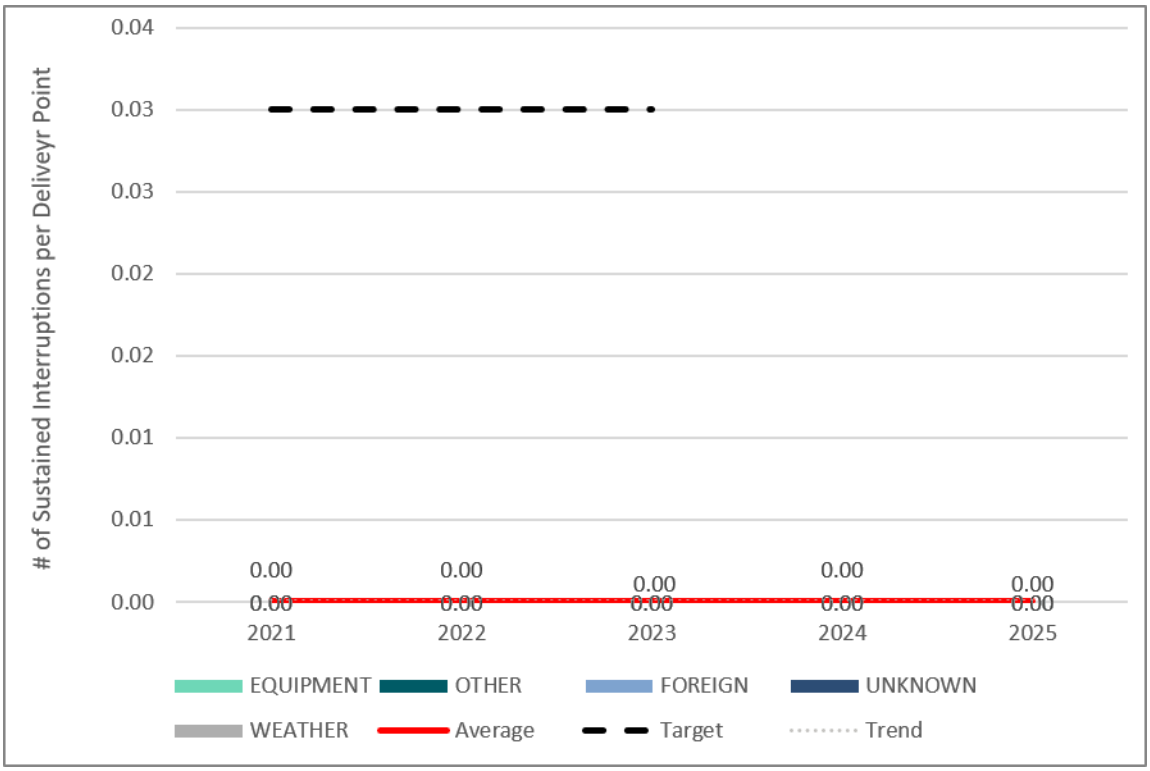

Figure 3: Transmission System Average Interruption Frequency Index – Momentary

TARGETS

Over the 2027-2032 period, HOSSM aims to maintain T-SAIFI-M performance at 0. Targets have been presented on the table below.

Table 4 - T-SAIFI-M Targets

	2027	2028	2029	2030	2031	2032
Target	0.04	0.04	0.04	0.04	0.04	0.04

3.2.3 T-SAIDI

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

The average duration of sustained interruptions per Delivery Point in 2025 was 24.6 minutes, a decrease of 0.5 minutes or about 2% compared to 2024.

HOSSM's average performance over the past five years (2021-2025) was 45 minutes (see Figure 4 below) and the five-year performance trend is improving. T-SAIDI performance can vary significantly from year to year for the following reasons:

- the small number of Delivery Points can cause the index to fluctuate appreciably;
- a small number of events can cause the index to fluctuate appreciably;
- major events are distributed randomly over the years; and
- radial supplied Delivery Point performance can vary significantly because these Delivery Points lack alternative means of supply in the event of an interruption.

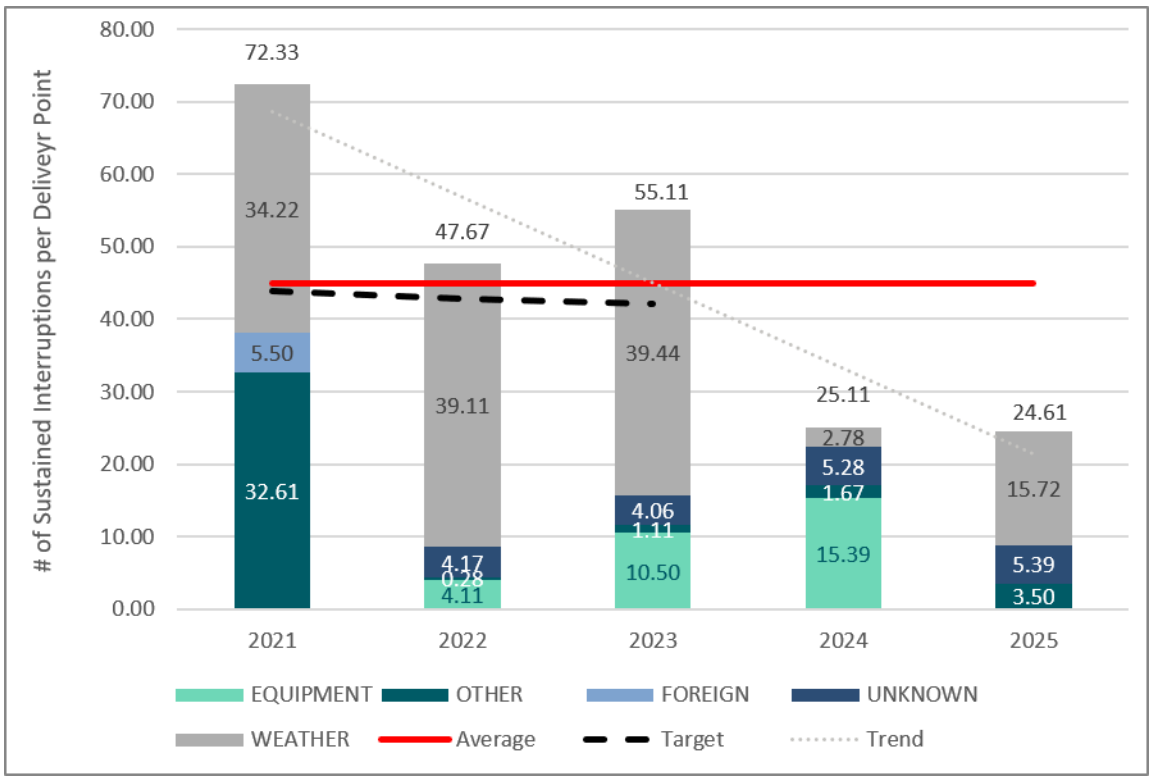

Figure 4: Transmission System Average Interruption Duration Index (Minutes)

Table 5 - Transmission System Average Interruption Duration Index (Minutes)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	45.6	44.7	43.8	42.9	42.1	N/A	N/A	
Actual	40.1	167.6	72.3	47.7	55.1	25.1	24.6	▼

TARGETS

Over the 2027-2032 period, HOSSM aims to improve T-SAIDI performance by 2% over 6 years to align with Hydro One methods. Targets have been presented in the table below.

Table 6 - T-SAIDI Targets

	2027	2028	2029	2030	2031	2032
Target	44.9	44.7	44.5	44.4	44.2	44.0

3.2.4 SYSTEM UNAVAILABILITY

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

For 2025, System Unavailability was 0.79%, which is in line with the 2024 result. System unavailability in 2025 was largely driven by long duration outages on breakers. Historical System Unavailability is presented on the table below.

Table 7 - System Unavailability (% Time Unavailable)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Actual	0.01%	0.08%	0.34%	0.01%	0.55%	0.78%	0.79%	▲

HOSSM's average System Unavailability over the past five years (2021-2025) was 0.49% and the performance trend indicates an increase in system unavailability over this period.

TARGETS

Over the 2027-2032 period, HOSSM aims to improve system unavailability performance compared to recent years. Targets have been presented in the table below.

Table 8 - System Unavailability (% Time Unavailable) Targets

	2027	2028	2029	2030	2031	2032
Target	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%

3.2.5 UNSUPPLIED ENERGY

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Unsupplied Energy for 2025 was 10.3 system minutes, which was higher than the 2024 result due to more weather-related interruptions. Due to the limited number of Delivery Points, substantial fluctuations can occur from one year to the next. Historical Unsupplied Energy is presented on the table below.

Table 9 - Unsupplied Energy (System Minutes)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	12.3	12.1	11.9	11.6	11.4	N/A	N/A	
Actual	30.7	23.8	31.2	16.5	32.7	7.1	10.3	▼

HOSSM's average performance over the past five years (2021-2025) was 19.5 minutes of unsupplied energy and the performance trend is improving.

TARGETS

Over the 2027-2032 period, HOSSM aims to improve Unsupplied Energy performance by 2% over 6 years to align with Hydro One methods. Targets have been presented in the table below.

Table 10 - Unsupplied Energy (System Minutes) Targets

	2027	2028	2029	2030	2031	2032
Target	19.4	19.4	19.3	19.2	19.1	19.0

3.3 ASSET & PROJECT MANAGEMENT

The measures in this group track Hydro One's performance in accomplishing the work necessary for the safe and reliable operation of the Transmission System. They cover the investments necessary to renew the system, maintain service to customers, and expand the system to serve new customers or accommodate infrastructure development. The measures address capital investments and Operations, Maintenance, & Administration spending.

3.3.1 IN-SERVICE ADDITIONS (% OF OEB APPROVED PLAN)

Performance Category	Measure	Description
Asset & Project Management	In-Service Additions (% of OEB Approved Plan)	HOSSM measures the progress of in-service additions as the ratio of actual total in-service additions to the total amount of planned in-service additions. For the 10-year deferred rebasing period, in-service additions are measured against budgeted amounts in lieu of an OEB approved plan.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

HOSSM measures the progress of in-service additions as the ratio of actual total in-service additions to the total amount of planned in-service additions. In-service addition performance is presented in the table below.

Table 11 - In-Service Additions (% of OEB Approved Plan)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	100	100	100	100	100	100	100	
Actual	425%	102%	115%	35%	148%	47%	104%	▼

In-service additions in 2022 and 2024 were lower than planned primarily due to the Sault #3 115 kV Transmission Line project. Following operational integration, Hydro One identified additional scope based on asset condition, which extended project development and delayed construction. As a result, the associated in-service additions were deferred. The project was substantially completed in 2025 and has since been placed into service.

TARGETS

Over the 2027-2032 period, HOSSM aims to complete 100% of the annual planned in-service additions.

Table 12 - In-Service Additions (% of OEB Approved Plan)

	2027	2028	2029	2030	2031	2032
Target	100	100	100	100	100	100

3.3.2 CAPITAL EXPENDITURES AS PERCENT OF OEB APPROVED PLAN

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

HOSSM measures the progress of capital expenditures as the ratio of actual total capital expenditures to the total amount of planned capital expenditures. Capital expenditures as a percent of OEB approved plan are presented in the table below.

Table 13 - Capital Expenditures (% of OEB Approved Plan)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	100	100	100	100	100	100	100	
Actual	30%	67%	82%	57%	71%	76%	103%	▲

Over the 2019-2024 period, Capital Expenditures were below target primarily due to the following:

- During the 2019-2022 period, the HOSSM capital plan was updated following operational integration with Hydro One. As a result, funding was allocated to complete legacy projects (those started prior to operational integration) and to the wood pole replacement program (planned and unplanned).
- During the 2023-2025 period, capital expenditures increased compared to 2019-2022 as new projects began to be executed.

TARGETS

Over the 2027-2032 period, HOSSM aims to complete 100% of the annual planned capital expenditures.

Table 14 - Capital Expenditures (% of OEB Approved Plan)

	2027	2028	2029	2030	2031	2032
Target	100	100	100	100	100	100

3.4 COST CONTROL

3.4.1 TOTAL OM&A AND CAPITAL PER GROSS BOOK VALUE OF IN-SERVICE ASSETS

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Total OM&A and capital expenditure relative to the gross fixed asset value in 2025 was 22.93%, or 3.0% lower compared to 2024, due to an increase in Gross Book Value of In-Service assets tied to in-servicing of a considerable portion of the Sault #3 115kV Line Refurbishment project. Total OM&A and Capital per Gross Book Value of In-Service Assets is presented in the table below.

Table 15 - Total OM&A and Capital per Gross Book Value of In-Service Assets (%)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	4.83	5.87	5.65	5.66	4.93	N/A	N/A	
Actual	5.89	6.20	8.40	9.79	18.47	25.93	22.93	▲

HOSSM's average performance over the past five years (2021-2025) was 17.1% and the performance trend is rising.

TARGETS

For 2027 and 2028, HOSSM is targeting a ratio of 10.62% and 14.69%. Targets for 2027-2032 will be updated based on the OEB approved amounts determined in this Application and through the application of the Custom IR framework's annual update applications.

Table 16 - Total OM&A and Capital per Gross Book Value of In-Service Assets (%) Targets

	2027	2028
Target	10.62%	14.69%

3.4.2 SUSTAINMENT CAPITAL PER GROSS FIXED ASSET VALUE (%) (REMOVE)

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Total sustainment capital expenditure relative to the gross fixed asset value in 2025 was 14.33%, or 2.74% higher compared to 2024, due to the increase related to the Sault #3

115kV Line Refurbishment project. Total Sustainment Capital per Gross Book Value of In-Service Assets is presented in the table below.

Table 17 - Sustainment Capital per Gross Fixed Asset Value (%)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	1.93	2.90	2.77	2.84	2.27	N/A	N/A	
Actual	1.23%	1.88%	4.03%	5.29%	12.15%	11.59%	14.33%	▲

HOSSM's average performance over the past five years (2021-2025) was 9.48% and the performance trend is rising.

TARGETS

HOSSM proposes to remove this measure as the 2028-2032 capital plan is predominantly system renewal work and therefore is largely reflected in the "CapEx as % of OEB approved plan" measure.

3.4.3 OM&A PER GROSS FIXED ASSET VALUE (%)

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Total OM&A relative to the gross fixed asset value in 2025 was 2.59%, or 0.64% lower compared to 2024, due to an increase in Gross Book Value of In-Service assets tied to in-servicing of a considerable portion of the Sault #3 115kV Line Refurbishment project. Total OM&A per Gross Book Value of In-Service Assets is presented in the table below.

Table 18 - OM&A Per Gross Fixed Asset Value (%)

	2019	2020	2021	2022	2023	2024	2025	Trend
Target	2.90	2.97	2.89	2.81	2.61	N/A	N/A	
Actual	4.56	4.16	3.86	3.65	3.51	3.23	2.59	▼

HOSSM's average performance over the past five years (2021-2025) was 3.37% and the performance trend is declining.

TARGETS

For 2027 and 2028, HOSSM is targeting a ratio of 2.23% and 2.12%. Targets for 2027-2032 will be updated based on the OEB approved amounts determined in this Application and through the application of the Custom IR framework's annual update applications.

Table 19 - OM&A Per Gross Fixed Asset Value (%) Targets

	2027	2028
Target	2.23	2.12

4.0 PUBLIC POLICY RESPONSIVENESS

4.1 CONNECTION OF RENEWABLE GENERATION

4.1.1 ON-TIME COMPLETION OF RENEWABLES CUSTOMER IMPACT ASSESSMENTS (REMOVE)

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Over the past five years (2021-2025), HOSSM did not receive any renewable generation CIA requests, resulting in no assessments requiring completion.

TARGETS

HOSSM is proposing to remove this metric on the same basis as Hydro One and as discussed in TSP Section 2.5: Hydro One is proposing to remove this metric because the regulatory provisions under O. Reg. 326/09 that established a distinct 150-day timeline for completion of assessments for renewable generation connections no longer exists. With this revocation, renewable generation projects are now treated under the same connection assessment framework as all other transmission-connected generators, without a separate timeline requirement.

As a result, maintaining a standalone metric for "renewables CIAs" is no longer relevant or reflective of the current regulatory requirements. Furthermore, in recent years HOSSM has had no renewable-specific CIA requests, further supporting the removal of this metric.

4.2 REGIONAL INFRASTRUCTURE PLANNING AND LONG-TERM ENERGY PLAN RIGHT SIZING

4.2.1 REGIONAL INFRASTRUCTURE PLANNING PROGRESS (CONSOLIDATED WITH HYDRO ONE)

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Historical performance and future year targets for this metric are reported on a consolidated basis for Hydro One Transmission and HOSSM in TSP Section 2.5.

5.0 FINANCIAL PERFORMANCE

5.1 FINANCIAL RATIOS

The measures below were selected to provide financial visibility and to demonstrate that the continuous improvements in execution and cost performance highlighted in 'Operational Effectiveness' are sustainable. The measures used for this scorecard align with the Financial Ratio measures used in the Electricity Distributor Scorecard.

5.1.1 LIQUIDITY: CURRENT RATIO

Performance Category	Measures	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 is defined as cash or other assets to be converted to cash within the year. Current liabilities is defined as short term debts or financial obligations that become due within the year.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

HOSSM reported a current ratio of 0.04 in 2025. The 2025 result indicates that for every one dollar of current liabilities, HOSSM had $0.04 in current assets.

Table 20 - Liquidity: Current Ratio

	2019	2020	2021	2022	2023	2024	2025
Actual	1.32	1.12	1.75	0.23	0.28	0.08	0.04

HOSSM current ratio over the past five years (2021-2025) is trending downwards due to lower current assets and/or higher current liabilities. Due to the nature of this measure, HOSSM has not provided a forecast outlining future financial performance expectations.

5.1.2 LEVERAGE: TOTAL DEBT TO EQUITY RATIO

Performance Category	Measures	Description
Financial Ratios	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	The debt-to-equity ratio is a measure of HOSSM's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60 per cent to 40% debt-to-equity structure (a ratio of 1.5).

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

HOSSM's total debt to equity ratio as measured for its business was 0.51 in 2025. The debt to equity ratio is a measure of HOSSM's financial leverage and serves to identify the ability to finance assets and fulfill creditor obligations.

Table 21 - Leverage: Total Debt to Equity Ratio

	2019	2020	2021	2022	2023	2024	2025
Actual	0.86	0.85	0.76	0.68	0.61	0.55	0.51

HOSSM's debt to equity ratio has been trending downwards, which is primarily attributable to the decrease in total debt.

5.1.3 PROFITABILITY – ACHIEVED REGULATORY RETURN ON EQUITY

Performance Category	Measures	Description
Financial Ratios	Profitability: Regulatory Return on Equity - Deemed Return on Equity (included in rates)	Measures the OEB-approved Return on Equity that is embedded in the transmitter's base rates. Return on Equity is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

HOSSM's 2025 achieved regulatory return on equity (ROE) was 17.07%, against an OEB-deemed ROE of 9.19%.

Table 22 - Achieved Regulatory Return on Equity (%)

	2019	2020	2021	2022	2023	2024	2025
Deemed	9.19	9.19	9.19	9.19	9.19	9.19	9.19
Actual	10.56	14.48	16.57	17.54	19.45	20.10	17.07

Historically, HOSSM's achieved ROE has been above the deemed ROE, driven largely by higher-than-expected revenue from weather-related variability, and lower OM&A arising from efficiencies. Under HOSSM's Earnings Sharing Mechanism (ESM), earnings exceeding the deemed ROE by more than 300 basis points during the last five years of the deferred rebasing period were shared with ratepayers on a 50:50 basis.

Due to the nature of this measure, HOSSM has not provided a forecast outlining future financial performance expectations, except that the company strives to achieve the OEB deemed return.

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SECTION 2.10 – ATTACHMENT 4 – HOSSM – APPENDIX 2-G – SERVICE RELIABILITY AND QUALITY INDICATORS

This attachment has been filed separately in MS Excel format.

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SECTION 2.11 – TSP – CAPITAL WORK EXECUTION STRATEGY

2.11.1 INTRODUCTION

This Exhibit details how Hydro One executes its large and complex portfolio of capital work on the stations, lines and equipment that comprise the transmission system (the Capital Work Program). Hydro One's rigorous approach to planning and executing work, which is described in this Exhibit, will enable the company to achieve its forecast transmission capital investments.

The selection and prioritization of capital work is determined through the Investment Planning process discussed in SPF Section 1.7. This evidence focuses on how Hydro One executes the planned investments through programs and projects.

Hydro One has demonstrated the ability to successfully deliver large capital work plans and reduce the variability of its capital expenditures and in-service additions. This is the result of a mature capital delivery process with strong oversight, governance and expertise, and efficient execution resourcing using both Hydro One's skilled internal workforce and qualified external contractors. The capital delivery process includes both a Project Delivery Model and Program Delivery Model which create a repeatable and rigorous approach to executing the projects and programs which comprise the Capital Work Program. The capital delivery process is adaptable to accommodate the necessary growth in capital work and includes a continuous improvement model to ensure that it is driving best practices.

Hydro One's transmission capital delivery process has been independently reviewed and compared against the processes of industry peers by E Source Inc. (see TSP Section 2.3, Attachment 1). E Source concluded that Hydro One has a mature project delivery process that performs very well relative to industry peers and has improved in maturity and quartile rankings compared to the previous study completed in 2020.

This Exhibit includes a detailed discussion of the Project Delivery Model and the Program Delivery Model. The various phases of the models are discussed with emphasis on the

processes and methods followed to optimize capital work execution. The Exhibit also includes descriptions of the key organizational functions accountable during the execution process including estimating, scheduling, project controls, change management, oversight and governance. The Exhibit continues with details of the main factors which impact capital work execution, including resources and safety. The Exhibit concludes with a description of the continuous improvement initiatives Hydro One has implemented to continuously refine its capital delivery process into the next rate period.

2.11.2 CAPITAL DELIVERY PROCESS

The transmission capital delivery process starts with the planning and prioritization of capital work through Hydro One's Asset Management and Investment Planning Process (see SPF Section 1.7). As outlined in that section, capital work is planned to address asset condition and anticipated system needs using a risk-based approach. The product of the planning process is a series of investment needs that are met through the development of transmission capital projects and programs, including System Access and System Service Investments which are non-discretionary and required to connect customers and reinforce the system.

Projects and programs are the vehicles by which Hydro One's transmission Capital Work Program is planned and delivered. A project is defined as a specific undertaking at a particular location that occurs during a specific time and may extend beyond one fiscal year. Together, the projects form the Project Portfolio. Alternative approaches can be taken to achieve project objectives and there is a greater level of risk because each project includes a unique combination of elements related to the work to be executed and site conditions. Execution of the Project Portfolio follows the Project Delivery Model detailed below. An example of a project is refurbishment of a Transmission Station. A program is defined as a specific body of work where the type of work is repetitive, recurs year after year. Together, the programs form the Program Portfolio. Execution of the Program Portfolio follows the Program Delivery Model detailed below. An example of a program is Pole Replacements. Together, the Project Portfolio and the Program Portfolio form the transmission Capital Work Program.

2.11.2.1 PROJECT DELIVERY PROCESS

The Project Portfolio makes up approximately 80% of the total Capital Work Program. Once the Investment Planning Process has determined what investments are required, as discussed in SPF Section 1.7, Hydro One's Project Delivery Model is used to develop and execute the projects necessary to meet the Investment Plan. The Project Delivery Model has three phases:

1. Project Initiation
2. Project Definition:
   a) Project Scoping
   b) Project Planning
3. Project Execution:
   a) Execution Phase
   b) Project Closure

The Project Delivery Model is illustrated in Figure 1 below. Each of the phases and sub-phases is discussed in the sections that follow.

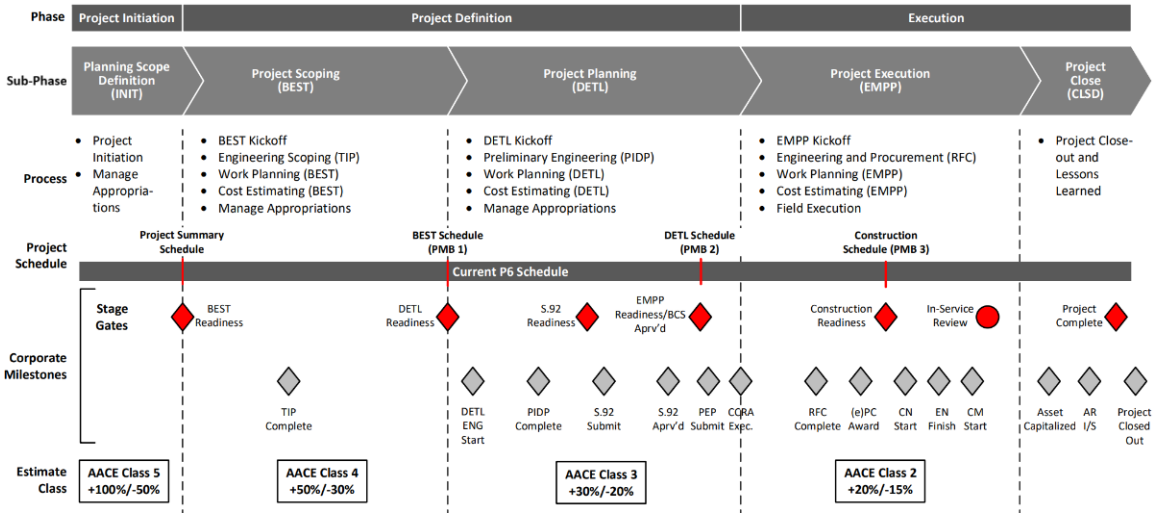

Figure 1: Transmission Capital Project Delivery Model

At the completion of each sub-phase, all projects with a material cost and/or reputational impact to Hydro One go through a Stage Gate Review. Stage Gate Reviews are held to evaluate a project's progress against plan and to determine whether a project should proceed to the next phase of the Project Delivery Model. For larger projects, Hydro One

defines five stage gate approvals for each project: one in Project Initiation, two in Project Definition, one in Project Execution and one at Project Close.[1] The review is conducted by the Capital Portfolio Delivery Vice-President and includes participation from Vice-Presidents and Directors across the organization who are responsible for sub-elements of the project plan (e.g. Planning, Engineering, Project Controls, etc.).

2.11.2.1.1 PROJECT INITIATION

In the Project Initiation Phase, Planning takes the needs identified in the Investment Planning Process and develops them into projects with high-level project scopes. The Planner evaluates the scope of work and engages with the necessary lines of business including Engineering, Station Services, Transmission Lines, External Relations, and Indigenous Relations to provide further expertise. The Planner, with input from Project Delivery[2], assesses the appropriate path through the delivery model based on the project scope and complexity (see TSP Section 2.11.6.1). This process includes clarifying assumptions that are project-specific and form the basis of the scope, including current asset condition, anticipated IESO requirements, schedule constraints, and identifying interim milestones for the subsequent Project Definition Phase, enabling the company to monitor progress and identify challenges early in the process. From this work, a high-level planning allowance and project summary schedule are identified with input from Project Delivery using comparator projects and execution expertise.

At the Project Initiation Phase, estimates rely on planning-level costs to provide indicative cost estimates. Planning-level costs are annually updated to reflect changes in market conditions. Given the long time horizon of a project, cost assumptions used during the Project Initiation Phase become out-of-date as the project progresses through the Project Delivery Model phases. During the subsequent Project Definition Phase, cost assumptions are further refined to mitigate estimating risks based on available information and through integration of expertise from cross-functional teams.

[1] As discussed in Section 2.11.6.1, smaller projects go through a simplified process.
[2] Project Delivery is the organization within Hydro One comprised largely of Project Managers that are involved throughout the lifecycle of a project.

2.11.2.1.2 PROJECT DEFINITION

The Project Definition Phase consists of two sub-phases: Project Scoping and Project Planning. Project Definition is led by the Project Delivery group and accomplished using cross-functional teams. These teams include Hydro One professionals from engineering, project controls, real estate, environmental services, construction services, system operations, supply chain, and maintenance workgroups, as well as the various lines of business representing customers, communities, including Indigenous Communities, and external agencies. The Project Definition Phase allows for early integration of diverse expertise across disciplines and workgroups while the project plan is being defined. This collaborative approach ultimately reduces risk, improves cost and schedule certainty, and ensures project plans are viable prior to project execution.

In the Project Scoping and Project Planning sub-phases, a project's scope of work and execution plan are further refined. The refinements include developing the work staging plan, the integrated project schedule and cost estimates (including risk/opportunity registers and a basis of estimate). As work in the Project Definition Phase progresses and project requirements are further developed, including a more detailed design, a bottom-up, task-based estimate with identified risks and assumptions can be developed, resulting in increased estimate accuracy.

2.11.2.1.2.1 PROJECT SCOPING

The objective of Project Scoping is to produce a final scope of work, which includes an Association for the Advancement of Cost Engineering (AACE) Class 4 estimate and schedule.

Project Delivery conducts a site meeting with the project team to review the constructability, operability, maintainability, safety and environmental impacts of the project. This gives the project team an opportunity to identify any outage requirements or incremental scope, such as components that may need to be made compliant with applicable standards. The project team also identifies long-lead materials requiring procurement and environmental assessment requirements to be completed during Project Planning. Anticipated execution risks and potential outage issues arising from customer constraints or geographic

concerns may also be incorporated into the project plan during scoping. Consideration of Indigenous consultation requirements occurs at this stage, including developing an understanding of how a project may impact Indigenous communities and their rights.

At the end of Project Scoping, a preliminary project execution plan is completed, which contains an initial estimate and a schedule that identifies relevant project milestones selected from a pre-determined list. The project must also pass through the Project Planning Readiness stage gate before proceeding to the Project Planning sub-phase. There is a standard set of planning criteria that are used to measure the projects' readiness to proceed, and the criteria are aligned with the key deliverables of the Project Delivery Model. These are based on industry best practices and include factors such as developing an appropriate outage staging plan; ensuring that land access and environmental requirements are met; demonstrating a plan to support the necessary regulatory submissions and approvals; ensuring that appropriate consultation plans are in place with customers, communities, including Indigenous Communities, and generators.

At this phase of the project delivery process, sufficient cost-based estimates and available site-specific information have been developed to prepare an AACE Class 4 estimate, which has an expected accuracy range of minus 30% to plus 50% (see TSP Section 2.11.2.1.4.2.1 for more on the AACE estimating process). Projects that are permitted to pass the stage gate are viewed as ready to meet the schedule and cost outcomes presented within the estimate accuracy bands for the current stage of project development.

2.11.2.1.2.2 PROJECT PLANNING

In Project Planning, Project Delivery works with the cross-functional project team members to prepare a project execution plan that captures the scope, schedule, and cost requirements and identifies risks that have the potential to change these requirements. During this phase, the team may conduct preliminary stakeholder and Indigenous Community engagements. The engagements with Indigenous Communities are an important aspect of the environmental assessment process during Project Planning, as they provide opportunities to better understand their perspectives and participation regarding a project.

The project execution plan includes the following items, as referenced in the capital Project Delivery Model:

- Engineering package: At the conclusion of this phase, all major materials are identified, engineering studies and surveys are complete, all preliminary discipline-specific drawings and instructions for construction are complete, and phasing of the work is determined;
- Schedule: A more comprehensive schedule is prepared at this point identifying key activities by discipline and asset (for example, the timeframe to construct foundations and install breakers and transformers);
- Risk Registry: A risk registry is created to capture the potential execution risks and associated mitigation plans. To quantitatively analyze risk and develop project contingencies, a cross-discipline risk workshop is conducted for all projects over $10.0M, which identifies the potential likelihood and consequences of project risks (see TSP Sections 2.11.2.1.2 and 2.11.4.1 for more information on the risk definition and management). The output of the risk workshop informs the project contingency amount;
- Opportunities Register: An opportunities register is developed to document cost-efficiency or estimate reduction opportunities and forecast potential savings.
- Outage plan: A preliminary outage staging plan is prepared to identify the work planned for execution in each year, the elements that may need to be removed from service, system constraints, and contingency plans or bypasses if an outage is not an option.

An AACE Class 3 estimate with an expected accuracy range of minus 20% to plus 30% is prepared using information provided in the engineering deliverables and project execution plan. This entire package of materials is reviewed by Project Delivery in preparation for the Project Execution Readiness stage gate.

Between the Project Planning and Project Execution phases, the final plan is reviewed and approved by the appropriate expenditure authority. Upon approval, the project is expected to be executed according to the scope, cost and timeline set out in the project plan, within the AACE Class 3 expected estimate accuracy range.

2.11.2.1.3 EXECUTION PHASE

In the Execution Phase, work moves through the Project Execution and Project Closure sub-phases. Project Execution contains three steps: (i) detailed engineering and procurement; (ii) construction; and (iii) commissioning. Transmission capital work is executed by three lines of business, Stations Construction, Station Services, and Transmission Lines:

- Stations Construction is responsible for the safe, reliable, and efficient execution of construction services on transmission and distribution stations. The work is executed by Construction Trades Unions.
- Transmission Lines is responsible for executing the Capital Work Program in a safe, reliable, and efficient manner on the approximately 29,000 kilometres of transmission lines. This work is executed by the Power Workers Union (PWU) and Construction Trades Unions.
- Station Services is responsible for the safe, reliable, and efficient operation and maintenance of station assets located in approximately 300 Transmission Stations and 1,000 Distribution Stations. They are also responsible for commissioning activities for all transmission and distribution stations during capital work execution. The work is executed by PWU and Society of United Professionals (SUP) unionized employees.

2.11.2.1.3.1 DETAILED ENGINEERING AND PROCUREMENT

In this phase, detailed design packages are developed and issued for construction, environmental approvals are obtained, and major equipment is procured. Major equipment consists of critical components, typically with long manufacturing lead times, which require review and approval of drawings and test reports by Hydro One (for example, power transformers, high-voltage circuit breakers, and switches). See Exhibit C-06-01, Section 3 for a description of Hydro One's approach to inventory planning, procurement, and management of critical and long-lead items.

2.11.2.1.3.2 CONSTRUCTION

In collaboration with Engineering and Project Delivery, Construction Services, Transmission Lines, and Station Services (as the executing lines of business), review the

ready-for-construction engineering packages to verify that the design reflects the approved scope, validate constructability, identify any conflicts or omissions, update plans, and verify costs before moving into construction. These steps are taken to minimize errors and changes before construction begins, both of which can increase costs and cause delays.

In Project Execution, the project is built to the required technical standards and detailed engineering specifications. Project Delivery is responsible for coordinating all workgroups that contribute to delivering the work plan on time and in a manner that is safe and cost-effective. Project Delivery:

- monitors the work plan through regular communication with construction;
- manages change order requests, if required;
- ensures the timely delivery of material, equipment, and drawings; and
- provides monthly cost, schedule, and work accomplishment (scope) updates on the project for the purposes of month-end reporting as described below in TSP Section 2.11.4.1.1.

Detailed job planning and regular onsite planning meetings are used as key communication tools during the process. These tools are used throughout the construction phase including during site preparation, civil/electrical work, major equipment installation and site remediation activities to ensure the safe execution of planned project work.

2.11.2.1.3.3 COMMISSIONING

The Commissioning Phase commences following construction. All new station assets enter a structured, multi-stage commissioning process designed to validate safety, functional performance, and operational readiness. Projects transition to the Station Services and Operating divisions through a formal handover that includes the review of as-built documentation, completion of standardized site acceptance testing, verification of protection and control systems, and confirmation of Supervisory Control and Data Acquisition (SCADA) and communication interfaces. These controls ensure technical

integrity, compliance with regulatory and internal standards, and that all equipment is safe and ready for energization.

Once commissioning activities are complete, assets are formally transferred to the System Operations Division for integration into system monitoring and control. This includes configuration of operational parameters, alarms, and telemetry, validation of switching and operating procedures, and the entry of the equipment into outage management and long-term maintenance planning systems. This disciplined approach ensures that each capital asset enters service fully validated, safely integrated, and positioned to deliver reliable operational performance. It also reduces commissioning-related rework or delays and supports the long-term value of the investments.

2.11.2.1.3.4 PROJECT CLOSURE

The Project Closure Phase ensures that all post-in-service project closure activities are completed within agreed-upon timelines. Through the project closure process, the newly built or refurbished assets are transitioned into operations in a timely manner, and all records, drawings, and systems are updated to reflect the assets as-built.

A site meeting is held for transmission capital projects with a budget of $5.0M or greater to review project objectives and ensure they have been met and to verify that all deliverables have been accepted by stakeholders. The project closure process engages key individuals who participated in the project lifecycle to ensure knowledge transfer for future projects and to reinforce a culture of continuous improvement.

2.11.2.1.4 PROJECT MANAGEMENT AND CONTROLS

This section describes in more detail the process Hydro One uses to manage and control projects as they proceed through the Project Delivery Model.

2.11.2.1.4.1 PROJECT MANAGEMENT

Project Delivery Managers (PMs) are accountable for a project from the beginning of the Project Scoping phase through to Project Closure. PMs have the authority to design the project execution plan from the beginning, with the input of all supporting lines of business.

They are accountable for planning, coordinating, tracking, reporting, and mitigating risk and opportunities on the project during both the Project Definition and Project Execution phases. Successfully fulfilling these accountabilities requires PMs to have a broad set of skills, including leadership, communication, coordination, cost control, schedule management, and risk management. The PM is the single point of contact on a project and is critical to its success. They are required to manage the planned schedule and unplanned impacts to the schedule, such as outage delays, while maintaining schedule and cost commitments. Placing these accountabilities in a single individual reduces the handoffs during the project lifecycle and provides a consistent approach to planning, execution, and closeout. This approach leads to earlier recognition of potential issues and risks, and increases the likelihood of delivering projects on scope, schedule, and cost while managing any necessary changes.

2.11.2.1.4.2 PROJECT CONTROLS

Hydro One's Project Controls functions contribute to the efficient execution of its Project Portfolio by developing estimates, tracking, and reporting detailed project data with attention to schedule and cost metrics.

2.11.2.1.4.2.1 ESTIMATING

As mentioned above, Hydro One utilizes the AACE Classification Scheme, which is an industry-established estimating classification method intended to appropriately communicate and set expectations for estimate accuracy by project phase. The estimates are based upon the maturity of underlying deliverables associated with completed planning, engineering, and construction work. Through estimating software, Hydro One's estimating team maintains a structured catalogue of historical costs, enabling standardized and repeatable estimating practices across disciplines. This standardization enhances estimating consistency, accuracy, and overall operational efficiency.

To adapt to the scale of the Capital Work Program, Hydro One continuously develops its estimating methodology. This is accomplished through process alignment across estimating disciplines, enhanced review processes, standardization of change management, and strengthened governance. Collaboration between the Project Estimator,

Construction Estimator, and Commissioning Estimator ensures a comprehensive and accurate project estimate that is fully aligned with the overall scope. This enhanced collaborative review occurs at multiple levels within the project, including with Field Supervisors, Project Managers, Managers, and Directors reinforcing the rigour behind validating project information and confirming that the estimated cost and plan are well supported.

As the estimating process has evolved, collaboration between planning, engineering, and construction has increased. To facilitate this, the role of the Capital Delivery Planner was created to enhance project outcomes, improve planning accuracy, ensure constructability, mitigate risks, and support continuous improvement. With this, field experts were integrated into the commissioning estimating function, infusing the team with decades of field experience and execution expertise, resulting in a robust, discipline-aligned estimating process that reflects operational realities and supports precision in planning, staging, and cost forecasting.

2.11.2.1.4.2.2 SCHEDULING

Hydro One utilizes Primavera P6 (P6) as a project scheduling tool. P6 is used to create standardized project schedule reports in both the Project Definition and Project Execution phases. The use of P6 improves communication of schedule information throughout the capital project delivery process.

In the Project Definition Phase, including both the Project Scoping and Project Planning sub-phases, P6 is used to capture schedule information, define the appropriate level of detail required at each phase in the delivery model, and conduct internal comparisons of schedule duration across similar projects.

In the Execution Phase, a standard work breakdown structure is applied consistently, together with a defined set of business rules and standard templates for all investments. This standardization ensures consistency in approach and level of detail between the way work is scheduled and the way it is estimated and executed. A consistent set of project milestones is used to present a standard view of individual projects and the overall portfolio,

which provides enhanced visibility into resource planning and scheduling and facilitates rapid monitoring of project and portfolio performance.

2.11.2.1.4.2.3 CHANGE MANAGEMENT

Change Management is the process of controlling project information to determine how to efficiently implement changes from the project plan. Hydro One's change management process allows project teams to track costs and forecast and communicate variances in resourcing and expenses both during a project and at Project Closure.

Hydro One's change management process continues to evolve in response to a growing transmission capital Project Portfolio. Improvements to change management include quantity changes, which help identify when changes related to designs or volumes of equipment/material have occurred, such as the number of required switches or length of trenches. In addition, automated reporting tools have been implemented to support cost controllers and field staff with monitoring workflows, improving visibility into change order status and potential project impacts.

2.11.3 PROGRAM DELIVERY PROCESS

The Program Portfolio makes up approximately 20% of the total Capital Work Program. The Program Portfolio is planned and executed using a programmatic methodology with a focus on like-for-like planned asset replacement (for example, insulators, wood poles, and tower coating) as well as unplanned replacements. The transmission capital Program Portfolio is executed by three lines of business: Stations Construction, Station Services, and Transmission Lines. The planning of a program is less involved than that of a project given the repeatable nature of the work involved.

The Program Delivery Model has three phases:

1. Program Planning;
2. Program Development:
    i. Work Program Planning; and
    ii. Work Initiation and Scheduling;
3. Program Execution.

Each of these phases and sub-phases is discussed in the sections that follow. Figure 2 depicts the Program Delivery Process starting from initial planning through to execution.

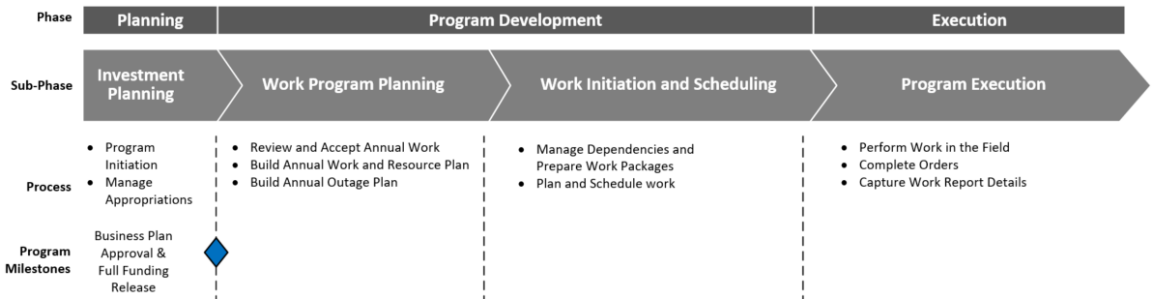

Figure 2: Transmission Capital Program Delivery Model

2.11.3.1 PROGRAM PLANNING

The Investment Planning Process involves the identification of the scope of program work through the planning and prioritization process identified in SPF Section 1.7. Transmission capital program work is released on an annual basis after the approval of the Hydro One Investment Plan. Program managers and the execution lines of business are involved in the Investment Planning Process to ensure that execution factors are considered in optimizing the delivery of the Program Portfolio. This collaborative effort also allows for program scope and cost to be determined at the Program Planning phase using planning-level costs. Visibility to future-year (usually two additional years) scope is provided to the executing lines of business to help plan resources, training, and material purchases. Additionally, it gives them the opportunity to gain efficiency by bundling work geographically or bringing work forward if an execution challenge is encountered (for example, a cancelled outage, resource conflict, or permit issue).

2.11.3.2 PROGRAM DEVELOPMENT

2.11.3.2.1 WORK PROGRAM PLANNING

Following the Program Planning phase, the Program Development phase begins. The Program Development phase includes the Work Program Planning and Work Initiation and Scheduling sub-phases, which focus on the refinement of scope, schedule, cost, and execution strategies. During the Work Program Planning phase, the Work Management Team, comprising program managers, works with the executing lines of business to plan

the outages, resources, material, and equipment to safely and efficiently deliver the planned work program. The Work Management Team seeks to further optimize the work program, looking at enablers such as resources and system outages across the entire Program Portfolio. For example, Station Services and Transmission Lines bundle work across multiple programs to ensure resource efficiency by executing as many units as possible during an outage, while the Environmental Services team helps to plan the work in a way that minimizes environmental impacts, such as by replacing wood poles in ecologically sensitive areas when the ground is frozen.

2.11.3.2.2 WORK INITIATION AND SCHEDULING

Throughout the Work Initiation and Scheduling phase, detailed work packages are prepared for the execution workgroups, capturing material, equipment, and standards required to complete the work safely. Program work is scheduled for execution considering the criticality of work, resource availability and utilization, staff and public safety, and the requirement for system outages. Outage planning is initially done annually and refined through a continual process. Work is bundled during scheduling to make the best use of outages and resources, limiting the number of planned bulk electric system outages required.

2.11.3.3 PROGRAM EXECUTION

In the Program Execution phase, work is efficiently executed through to commissioning by three lines of business, Stations Construction, Station Services, and Transmission Lines. These three groups work closely with program managers to identify and report any unforeseen issues requiring additional time or resources, effectively reprioritizing work. They are responsible for providing meaningful input on the condition of assets and any potential risks or opportunities that may impact the Hydro One system. To increase efficiency while maintaining safety, Hydro One recently enhanced its ability to execute program work with the expansion of live-line work, thereby reducing the number of outages required in certain situations, which is beneficial for both the company and customers. Hydro One has highly trained and certified crews with strict procedures in place to ensure the work is performed safely.

2.11.4 PROJECT AND PROGRAM OVERSIGHT

This section presents Hydro One's approach to managing the overall Capital Work Program comprised of the Project Portfolio and Program Portfolio by tracking work accomplishments and cost performance and addressing the need for changes to project schedules and costs. This section also discusses the role of Hydro One's senior management in overseeing the delivery of the Capital Work Program.

2.11.4.1 TRACKING AND REPORTING

As part of its capital delivery process, Hydro One has established the mechanisms below to enable appropriate tracking and reporting of project and program progress.

2.11.4.1.1 REPORTING ON PROJECT AND PROGRAM STATUS

Hydro One reviews its project and program status monthly. Projects in the Project Definition Phase that are planned for construction in the next one to three years are reviewed from a readiness perspective. Projects in the Execution Phase are reviewed from an execution perspective. Hydro One uses a combination of standard reporting requirements, key performance indicators, and a change management approval process at the program, project, and portfolio levels to provide assurance that its capital work is being well managed.

This review process allows Hydro One to respond to a changing landscape as projects naturally encounter realities that differ from forecasts and estimates, such as outage constraints, delays in external approvals and material delivery, evolving customer needs, and emergent investment needs. Programs are reviewed against their plans for expenditures and unit replacements, with any changes in cost monitored throughout the year and against the previous year's performance.

Hydro One regularly reviews the amount of contingency held within each project with consideration of project status and risks/opportunities, future year capital expenditures and in-service addition assumptions. Although held at a project level, the overall contingency in the Project Portfolio is reviewed monthly to assess the allocation across the portfolio.

2.11.4.1.2 PORTFOLIO MANAGEMENT

Hydro One reviews its Capital Work Program monthly through multiple lenses to provide a comprehensive and detailed view of the Project and Program Portfolios. This ensures that work is being completed as planned and that insight into future work is available, allowing the company to adapt to demand and unforeseen circumstances.

The Capital Work Program is analyzed through three different lenses with multiple aspects reviewed within each lens. First, capital expenditures and in-service additions for the year are analyzed against the budget at a monthly, year-to-date, and year-end level. As part of this analysis, the Portfolio Management team takes into consideration the risks and opportunities for specific projects and programs and the effect on the Capital Work Program. Additionally, contingency for the Project Portfolio and units for the Project Portfolio and Program Portfolio are analyzed to review how much work is left for the year and the overall impact these factors have on the respective portfolios. Second, projects are reviewed on a project-total basis to confirm they are on track and on budget, and to identify variances where applicable and take appropriate action. Lastly, the Capital Work Program is evaluated under a multi-year lens to review the upcoming work for the next five years and determine portfolio readiness (that is, the percentage of future work that is currently in the Planning Phase versus the Execution Phase). In this view, the overall forecast and budget for the upcoming years are compared, showing the projects or programs driving any variance. Conducting portfolio management through multiple perspectives establishes a cohesive and thorough representation of the overall health of the transmission Capital Work Program.

2.11.4.2 GOVERNANCE

Hydro One utilizes various governance methods to review and monitor projects and programs to ensure costs and schedules are managed effectively and expectations are met across the portfolios.

2.11.4.2.1 STAGE GATE APPROVALS

Stage Gate Approvals provide ongoing visibility into individual project performance, risks, and issues and are an important input to the Project Portfolio review and governance process.

2.11.4.2.2 EXECUTIVE REVIEW

On a monthly basis the Capital Work Program is reviewed through a series of meetings starting at the Director level and advancing up to the responsible Vice-President and ultimately to the Executive Leadership Team.

2.11.4.2.3 REPRIORITIZATION

As discussed in SPF Section 1.7, reprioritization refers to the planning process by which changes are made to the investments included in Hydro One's Investment Plan.

2.11.5 FACTORS IMPACTING WORK EXECUTION

2.11.5.1 EXECUTION RESOURCES AND APPROACH

Hydro One will employ a range of resources to execute the Capital Work Program over the rate period, including internal resources, the casual building trades workforce and external resources provided through contracts with qualified service providers. The internal workforce will largely complete its work using regular time hours, but overtime will be used when necessary or to increase efficiency, as discussed below.

Hydro One has three internal workgroups that are accountable for executing its transmission Capital Work Program: Stations Construction, Transmission Lines, and Station Services.

Building Trades Unions and the PWU workforce will continue to execute most of the Capital Work Program to ensure that Hydro One remains a knowledgeable owner and efficiently manages risk when working on brownfield refurbishments. This approach allows for knowledge retention while supporting operational agility and long-term sustainability. Hydro One Transmission requires an increase in resources to be able to execute the increased Capital Work Program planned for the 2028–2032 period. Hydro One

Transmission plans to fill the majority of the increased resource demand with casual trades staff starting in 2028. During the 2028–2032 period, Hydro One Transmission forecasts a relatively flat regular headcount while absorbing the increased workload through casual resources and by taking advantage of efficient outsourcing opportunities to maintain flexibility, scalability, and cost control. See Exhibit E-06-02 Workforce Planning for more details on the transmission resource plan for 2028–2032.

Overtime levels are expected to be like those in previous years. Overtime is typically required to address imminent component failures and prioritized repairs to ensure assets are placed back in operational condition to avoid or address outages. Overtime usage is also required to perform outage work that is time-constrained and may need to be done during a customer outage (that is, an outage during plant shutdowns to mitigate production interruptions, typically weekends and holidays). Given that the timing of customer outages is difficult to predict and work must be performed at specific periods, overtime provides flexibility to accommodate these constraints.

Within transmission, overtime hours accounted for approximately 7% of all hours worked by Stations Construction, Transmission Lines, and Station Services in 2025, improving from the 2023 level of approximately 8%. The usage and planning assumptions for overtime are heavily scrutinized by the company. The Transmission Lines and Stations groups require that overtime be pre-approved by management and perform monthly reviews to monitor the prudent use of overtime. Opportunities for optimizing the use of overtime are reviewed and pursued where appropriate. Nevertheless, overtime is essential to execute the Capital Work Program efficiently. In certain situations, the most cost-effective approach is to complete more work over shorter durations rather than hiring (and thus on-boarding, training, supervising, and directing) additional employees to perform the same volume of work over a longer period. Moreover, it is not always the case that deploying additional workers on-site results in a proportionate increase in work completed. Beyond the optimal crew size for a given job, excess workers may hamper efficiency. Finally, for projects that require significant setup and takedown, using overtime to complete the job in one day rather than completing it over two days of regular time is safer and can reduce costs.

Hydro One's execution strategy over the rate period includes leveraging external delivery partners to complement existing internal teams and provide operational flexibility to meet the growing Capital Work Program. The company expects to require an increased volume of contracted-out work in the rate period to meet the demands of the increased capital investment portfolio. Demand for load growth investments is increasing and partnering with external delivery firms allows Hydro One to safely and efficiently respond to this demand. Hydro One works with these partners to find the most efficient way to execute the work program, which includes involving them early in the development phases to ensure that the scope of work and delivery method are clear and well understood.

A variety of services are used by Hydro One to help deliver its Capital Work Program including third-party engineering, procurement, and construction (EPC) services for select projects; specialty construction skills that are not retained within Hydro One (for example, tunnelling, high-voltage cable installation, and high-tech OEM and industrial buildings); and specialty equipment rentals with operators (for example, cranes and vacuum trucks for day-lighting buried services). In selecting the optimal model for the type of work, Hydro One has a pool of pre-qualified service providers for line refurbishments, buildings, substations, and high-voltage cable work and uses a competitive Request for Proposal process to select the best service provider for a particular work assignment. Externally delivered projects also adhere to the Project Delivery Model and are subject to the same Stage Gate governance, tracking and reporting as internally delivered projects.

Hydro One engages external delivery partners to increase agility, flexibility and the ability to scale up quickly to respond to a growing work program and deliver on strategic priorities. Hydro One plans to utilize its skilled internal resources to execute more complex tasks that require a high degree of coordination and cooperation throughout the organization and across the industry as well as some simple work that provides flexibility and training opportunities for its staff. This includes station refurbishments, customer connections, like-for-like program replacements and some transmission line refurbishment projects. Hydro One uses external delivery partners to respond to needs where the scope can be clearly delineated or where specific skillsets are not available internally, such as with high voltage cable projects and tunnelling activities.

2.11.5.2 SAFETY

Hydro One is committed to becoming the safest and most efficient utility through initiatives that drive operational performance in alignment with its values, vision, and mission. As shown in Figure 3, these initiatives have resulted in a steady decrease (improvement) in the Station Services, Stations Construction, and Transmission Lines recordable injury rate, despite substantial growth in the work program. These results represent best-in-class performance and reflect Hydro One's operational discipline, continuous improvement, and dedication to ensuring every employee goes home safe at the end of each day.

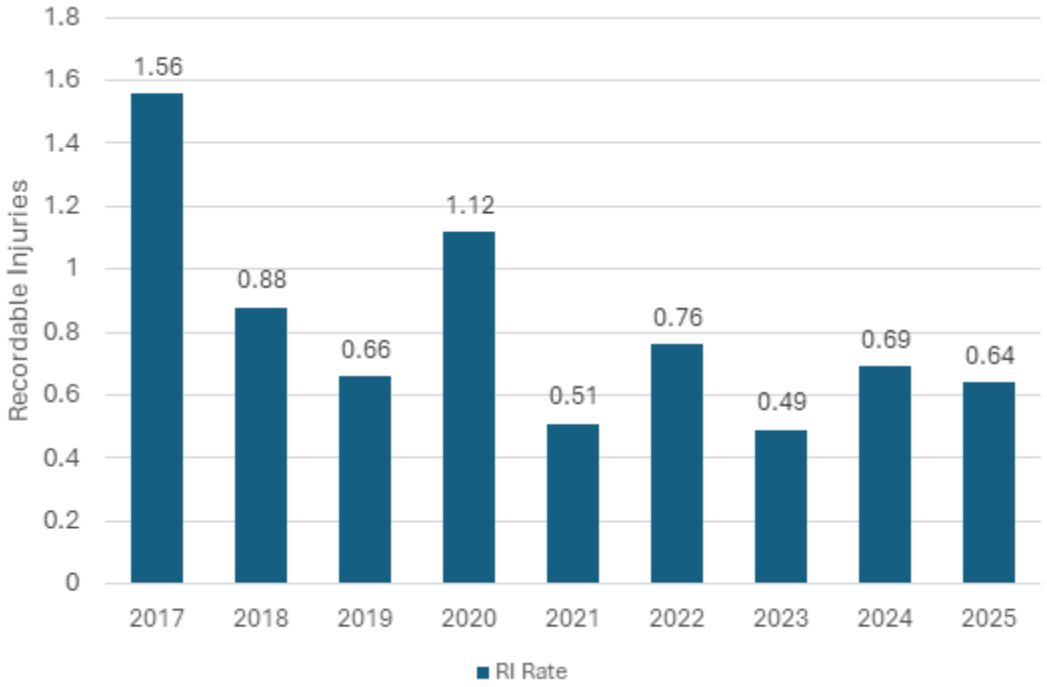

Figure 3: Recordable Injury Rate per 200,000 Hours Worked (Transmission and Stations)

In 2020, Hydro One created a dedicated Health and Safety Team to lead the transformation of the safety culture, and the Health, Safety, and Environment function was recently redesigned to provide a more effective focus on health and safety management systems, training and development, operations field support and learning, and analytics and reporting.

By the end of 2024, Hydro One successfully implemented 12 initiatives that established a strong foundation for long-term cultural change. Following the completion of the 2020–2024 Safety Improvement Plan, Hydro One has established its next phase of safety strategy.

The 2026–2030 Safety Refresh builds on the foundation of what was achieved over 2020–2024. Guided by employee input, it strengthens what is working and identifies new opportunities to enhance the company's safety culture. Seventeen initiatives across six strategic pillars have been identified, integrating physical and psychological safety into all aspects of life at Hydro One.

Hydro One has continued to influence and drive a safety-focused mindset throughout the lifecycle of a capital project. In 2023, improvements to safety oversight and governance during the construction phase of a project were introduced by formalizing the identification of hazards and risks in the Project Planning sub-phase. This improvement has enabled mitigation plans to be integrated into the project plan prior to execution commencing, ensuring improved visibility to safety risks and more time to define mitigation strategies.

For more information regarding the company's approach to safety in the execution of its transmission work, see Exhibit E-02-05 Transmission O&M Work Execution Strategy.

2.11.6 CONTINUOUS IMPROVEMENTS

Hydro One has recently undertaken several initiatives to increase the effectiveness and efficiency of its Capital Work Program delivery. These initiatives are described in the following sections.

2.11.6.1 TRANSMISSION CAPITAL PROJECT DELIVERY MODEL ENHANCEMENTS

In 2020, Hydro One launched an initiative to enhance the Transmission Capital Project Delivery Model. Although initially planned to conclude in 2021, this work marked the start of an ongoing commitment to continuously refine the model so it remains effective and scalable for transmission capital project delivery. Hydro One expects the positive

outcomes on capital project execution to continue throughout the rate period and has introduced a framework to drive continued improvements.

Several improvements were introduced in 2020 and 2021 that marked a significant shift in Hydro One's approach. These early enhancements focused on clarifying decision authorities, strengthening the role and influence of Project Delivery operating within a matrixed organization, and improving the predictability of project outcomes. Collectively, these foundational improvements strengthened current functioning processes, making them more robust, consistent, and effective. They delivered the following outcomes:

- Enhanced accountability and decision-making efficiency through refining and clarifying decision rights and obligations for each line of business involved in transmission capital projects. This enhancement built on existing practices to ensure decisions are not only timely and well-informed but also supported by clear ownership throughout the project lifecycle.
- Improved schedule reliability during the Execution Phase by further empowering Project Delivery to reinforce expectations and by introducing Work Package Agreements. These agreements elevated and formalized key milestones and cost commitments from each line of business. They also strengthened the tracking and reporting of Planning Phase commitments and ensured line of business leadership had validated resource availability before the start of the Execution Phase.
- Greater visibility, consistency, and control of project changes and funding through strengthened change management processes. This included adopting consistent terminology and cost deviation categories, refining the governance around how project changes are funded to better align with approval limits, and clearly defining responsibilities for the Control Account Manager within each line of business.

To support the sustained evolution of the Project Delivery Model, Hydro One developed a continuous improvement framework to strengthen consistency and alignment with Project Management best practices. A major milestone in this journey was the establishment of a Centre of Excellence (CoE) in 2021. The CoE was created to own, govern, and maintain the Project Delivery Model and remains accountable for ensuring its continued evolution. Its mandate includes driving consistent application of the Project Delivery Model (PDM)

across the organization, aligning project delivery practices across the portfolio, and enabling teams through guidance and best practices. Currently, the CoE acts as a supporting Project Management Office (PMO) with plans to evolve it into a controlling PMO, further enhancing project governance and increasing predictability, consistency, and transparency.

As part of ongoing continuous improvement efforts, Hydro One has continued to enhance how critical supporting lines of business are integrated into the Project Delivery Model, ensuring their input and expertise are captured at the appropriate points in the project lifecycle. Improvements have focused on better integrating Indigenous Relations, Community Relations, and Real Estate earlier in the project lifecycle to help reduce potential variability in later project phases. These changes emphasize clearer alignment of roles and responsibilities and reinforce consistent engagement by Project Delivery during the Project Scoping sub-phase when preliminary project plans are being developed. This approach ensures each supporting line of business has a timely opportunity to influence the project plan based on its specialized expertise and the interests it represents. In addition, the requirement for Work Package Agreements has been extended to include Indigenous Relations, Community Relations, and Real Estate, formalizing commitments and supporting accountability as projects progress through both Project Definition and Project Execution.

Recently, significant effort has also been directed toward enhancing the involvement of Station Services within the Project Delivery Model to improve the planning and execution of commissioning activities on capital projects. While Station Services has long played a key role in the delivery model, increased emphasis has been placed on engaging this function earlier and more consistently in the project lifecycle. As a result, formal commissioning planning has been advanced to the Project Scoping sub-phase, and roles and responsibilities have been realigned across all phases of the model, ensuring project plans reflect current asset and site conditions and ultimately alleviate schedule compression. Additionally, these improvements will provide earlier visibility into future resourcing needs and enable potential resourcing risks to be proactively identified and mitigated before they materialize.

The full Project Delivery Model is used for major transmission capital projects; however, there are avenues to accelerate the process based on project size and complexity to ensure that the level of rigour is fit for purpose. As a result, Hydro One developed alternative tailored paths through the Project Delivery Model for those projects that do not warrant all process requirements. The paths determine the appropriate combination of inputs, tools, techniques, and outputs to effectively deliver the project. A ranking system based on project cost and complexity has been developed to allow Hydro One to apply greater scrutiny and rigour to projects that expose Hydro One to a higher degree of risk during execution and apply a simplified approach to projects that do not require the full Project Delivery Model. This simplified tailored model has been applied on a limited number of projects and is still evolving to meet the needs of Hydro One's capital Project Portfolio.

2.11.6.2 CONTINUOUS IMPROVEMENT MODEL (FIELD PRODUCTIVITY INITIATIVES)

Over the 2021-2022 period, Hydro One implemented the Continuous Improvement Model (CIM) across multiple executing lines of business including Station Construction, Station Services, and Transmission Lines to further improve labour efficiencies in work execution. The CIM is a system of integrated elements to plan, execute, and measure work completion. It focuses on clarifying roles and accountabilities, resulting in more efficient work assignments, reduced variances between planned and actual project durations and decreasing downtime through increased scheduling efficiency. The CIM drives continuous operational effectiveness by ensuring safety, quality of service and cost management.

CIM provides a framework to address three fundamental areas:

- Providing a structured methodology and tools for more effective planning, work execution and reporting, which results in more efficient work execution.
- A province-wide problem resolution program that facilitates the identification, prioritization and tracking of continuous improvement opportunities in execution.
- Alignment of roles, responsibilities and accountabilities across the work management and execution teams that ultimately drives improved work execution.

The ongoing benefits of this program include the following:

- Improved safety culture and engagement of crews, through enhanced field leadership tools and work execution rigour;
- Improved efficiency through proactive identification and prioritization of high impact activities;
- Increased efficiency through the use of more consistent scheduling tools;
- Increasing coordination to improve work management efficiency and reduce engineering rework; and
- Improved coordination of field activities to reduce work durations.

Based on the CIM, Hydro One has implemented systematic processes to quantify, categorize and escalate issues that arise during work execution. Issues are analyzed and addressed through a resolution process, using a consistent escalation framework with levels corresponding to the importance of the issue, to drive the implementation of permanent solutions. This has proven to increase engagement as staff are stakeholders in the development of solutions.

2.11.6.3 EARLY CONTRACTOR INVOLVEMENT

For select larger projects, Hydro One has implemented an Early Contractor Involvement (ECI) initiative to ensure prudence in selecting optimum solutions and more reliable estimates during project execution. This approach involves the hiring of two EPC contractors during the development phases of a project, with emphasis on innovation and efficiency. The most optimized plan deliverables are used to competitively award a fixed-price contract to one of the two EPC contractors. This strategy supports the cost-effective delivery of large, high impact projects, and reduces execution risk to customers.

2.11.6.4 CREW SIZE OPTIMIZATION INITIATIVE

In 2025, Stations Construction, Transmission Lines and Station Services have launched initiatives to further refine the crew deployment approach to ensure optimal crew size while maintaining productivity and safety. This has led to reduced construction costs and the ability to complete more work. This was achieved through the development of a safe crew

sizing calculator, improved accuracy regarding time and unit reporting, and improved scheduling.

2.11.6.5 STREAMLINING ENVIRONMENTAL PERMITS AND APPROVALS INITIATIVE

Building off the success of the productivity savings realized through the Environmental Assessment (EA) Modernization initiative during the previous rate period, Hydro One is focused on assessing additional streamlining opportunities applicable to subsequent phases of the project lifecycle, namely via post-EA permitting processes. Efficiencies in this space will not only produce cost savings but improve schedule certainty which is an important consideration with a growing Capital Work Program, especially as many projects transition from planning to permitting and construction.

Certain project permits can be lengthy taking more than a year to obtain. Such timelines and uncertainty can strain project schedules in the lead up to construction start. To this end, Hydro One is assessing multiple opportunities to streamline internal processes as well as to engage with regulatory agencies to assess opportunities for sensible changes that create efficiencies while maintaining environmental protection and meaningful consultation. To inform this, concerted effort is needed to map out processes and timelines, and identify synergies across the portfolio, including the optimization of responsibilities in different execution models, for the broad scope of regulatory frameworks that currently apply.

2.11.6.6 TECHNOLOGY IMPROVEMENTS

Hydro One has made progress over the last five years in enhancing available technology. An area of focus is increasing data analytics and reporting capabilities through the usage of technology like Power BI. Adopting Power BI has enabled lines of business to create interactive dashboards and reports using multiple data sources while integrating into existing tools. Additionally, Hydro One is undertaking an initiative to update its SAP system to SAP S/4HANA. SAP S/4HANA is a real-time, integrated enterprise platform that supports end-to-end processes with embedded analytics and user-friendly reporting capabilities. It can be implemented with a Project Management Information System (PMIS)

tool which Hydro One is also exploring. The PMIS tool would merge disparate data sources into a single location that is easily accessed through the improved Power BI dashboards, enhancing reporting and analytics. These applications will increase efficiency, accuracy, and insights by optimizing processes and enabling collaboration. This allows individuals to focus more on value added reporting and drives strategic decision making across the organization, readying Hydro One for the growing Capital Work Program.

Hydro One's 2028-2032 plan to modernize information and operating technology systems includes investments in data analytics and artificial intelligence (AI). With an accelerated growth of data volumes across the company expected over the plan years, Hydro One is investing in data and AI platforms and marketplace to convert the data into actionable insight. These tools will enable a more efficient execution of capital work, improving scheduling, risk identification, resource optimization, and decision-making across project and program delivery processes, while reducing errors and variability. For further details about these data analytics and AI investments, see GSP Section 4.11, G-GP-26.

2.11.6.7 ESTIMATING IMPROVEMENTS

As mentioned above, Hydro One's estimating process has evolved to adapt to the growing Capital Work Program and will continue to advance through targeted enhancements to refine accuracy, efficiency, and cross-functional alignment. One key initiative includes introducing a cost breakdown structure, in addition to the existing work breakdown structure (WBS), to ensure consistency across all disciplines in project execution, scheduling, and reporting. The main benefit of a Cost Breakdown Structure, being applied in addition to the WBS, is that it provides enhanced visibility and control over costs by capturing costs at the equipment/material level, and enables improved budgeting, forecasting, reporting, and decision-making throughout the project lifecycle. Additionally, a formalized Estimate Preparation Plan will be introduced to establish clear expectations and standardize input requirements, ensuring completeness, traceability, and alignment. This reinforces a streamlined and disciplined approach, while also reducing estimate preparation and submission timelines. Bolstering alignment ensures a consistent and integrated approach to estimate development which will enable input refinement, strengthening input maturity and improving accuracy.

2.11.6.8 RESOURCE PLANNING IMPROVEMENTS

One major improvement made to resource planning is the development of the Transmission & Stations Integrated Resource Forecast (TSIRF) tool which presents a high-level forward looking resource forecast. It is used to inform high-level resource strategies, identify resource risks to the investment plan, inform contracting strategy (internal vs external), and coordinate cross-business work exchange with other lines of business. TSIRF is a cohesive solution, integrating high-level resource planning for Stations Construction, Transmission Lines, Station Services and Engineering into one application which previously was achieved through multiple tools.

To ensure accuracy and continuous improvement, a rigorous process is conducted each year with multiple runs of TSIRF which are then reviewed and validated by multiple stakeholders including field superintendents. Management uses TSIRF output as a consideration in workforce planning and its resource requirements that are forecasted as part of the larger Hydro One business planning process.

2.11.7 CONCLUSION

Hydro One has demonstrated that it can execute a very large and growing Capital Work Program while maintaining the flexibility needed to accommodate required adjustments in its capital work plan due to changing priorities, project challenges and emergent investments. The improvement initiatives discussed in this exhibit have been implemented to ensure that the company can conduct its increasing work program in a cost-effective, safe and reliable manner. The transmission capital work execution strategy will result in greater effectiveness throughout the project and program delivery process and increased accuracy in forecasting work and timelines. Adopting new technologies is central to these planned improvements. A continued focus on the business objectives of the transmission system plan including safety, quality, efficiency, and meeting customer commitments will ensure Hydro One’s success in accomplishing its Capital Work Program.

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SECTION 2.12 – TSP – MATERIAL INVESTMENT SUMMARY DOCUMENTS

2.12.1 INTRODUCTION

Transmission System Plan (TSP) Investment Summary Documents (ISD) are attached to this section. ISDs are provided where any proposed Hydro One capital expenditure within the TSP exceeds the materiality threshold of $4M in a single year or $0.29M in a single year for HOSSM. ISDs for General Plant investments are provided in the GSP Section 4.11 (Exhibit B-04-01).

Hydro One has endeavored to maintain the ISD structure from its previous transmission application (EB-2021-0110) and, where applicable, has added new ISDs and retired ISDs that are completed or are no longer required.

In the previous Application, investments that had capital expenditures below the materiality threshold were grouped within each OEB category as “Other” investments. In this Application, most investments (material or below materiality) have been assigned to an applicable ISD.

Based on the foregoing, investments may have expenditures assigned to one ISD in the 2023-2027 period (or “Other”) and forecast expenditures in the 2028-2032 period in another ISD. Therefore, the variance analyses in some ISDs include historical expenditures from another ISD from the previous Application, presenting expenditure trends on a comparable basis between the two periods.

Table 1 below presents the material Hydro One Transmission ISDs included in the TSP and Table 2 includes material HOSSM ISDs included in the TSP.

1 **Table 1 - TSP - Material Hydro One Investments**

ISD	Investment Title
	System Access
T-SA-03	Halton TS: Build a Second 230/27.6kV Station
T-SA-05	New & Future Transmission Load Connection Plans
T-SA-06	Protection And Control Modifications for Distributed Energy Resources
T-SA-07	Compatible Land Use Projects
T-SA-08	H29/H30: Reconductor 230kV Circuits
T-SA-09	New Transformer Station in Northern York Region
T-SA-10	Build Leamington Area Transformer Stations and Line
T-SA-11	Customer Connections – Regulated Entities
T-SA-12	Customer Connections – Non-Regulated Entities
	System Renewal
T-SR-01	Transmission Station Renewal - Network Stations
T-SR-02	Transmission Station Renewal - Air Blast Circuit Breakers
T-SR-03	Transmission Station Renewal - Connection Stations
T-SR-04	Wood Pole Structure Replacements
T-SR-05	Steel Structure Coating Program
T-SR-06	Tower Foundation Clean/Coat & Life Extension Program
T-SR-07	Transmission Line Shieldwire Replacement
T-SR-08	Transmission Line Insulator Replacement
T-SR-09	Transmission Station Demand and Spares
T-SR-10	Protection Relay Replacement Program
T-SR-11	Legacy SONET System Replacement
T-SR-12	Telecom Performance Improvements
T-SR-13	Transmission Line Renewal
T-SR-14	Mobile Radio System Replacement
T-SR-15	Transmission Line Emergency Restoration
T-SR-16	High Voltage Underground Cable System Replacements
T-SR-17	OPGW Infrastructure Projects
T-SR-19	Control Equipment Replacements
T-SR-20	Transmission Line Access and Right of Way Program Investment
T-SR-21	Static VAR Compensators and Series Capacitors Replacement Program
T-SR-22	Transmission Station Component Replacement

	System Service
T-SS-06	Southwest GTA Transmission Reinforcement
T-SS-09	West of London Transmission Reinforcement
T-SS-10	Greenstone Transmission Line Project - Station
T-SS-11	Bulk Planning
T-SS-12	Regional Planning
T-SS-13	Mitigating Short-Circuit Limitations at Hydro One Stations to Enable Resource Connections
T-SS-14	Bowmanville SS Loop Replacement
T-SS-16	Waasigan Station Work

ISDs are not included in this Application for the following investments because they have either been concluded or have expenditures below the applicable materiality threshold in the 2028-2032 rate period. Where applicable, material historic variances are described below:

- **T-SA-01 (New Customer Connection Station)** – Completed. One of two facility connections under this ISD were cancelled by the customer. Actual expenditures were approximately $6.3M under forecast, reflecting a combination of reduced scope of work and updated construction costs.
- **T-SA-02 (115 kV Mine Connection)** – Completed. Actual expenditures were approximately $4.7M under forecast as the project was completed on schedule, reducing costs associated with schedule risk.
- **T-SA-04 (Connect Metrolinx Traction Substations)** – This work was placed on hold due to customer scheduling, resulting in under-spending of approximately $4.2M, with immaterial spending remaining in the 2028-2032 period.
- **T-SR-18 (C5E/C7E Underground Cable Replacement)** – Completed. Actual expenditures were approximately $8.1M under forecast, due to lower project management, engineering and contract costs.
- **T-SS-02 (St Lawrence TS: Phase Shifter Upgrade)** – Completed.
- **T-SS-03 (Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade)** – Completed. Actual expenditures were approximately $5.1M under forecast, due to efficiencies from outage execution.

- **T-SS-04 (Richview x Trafalgar 230 kV Conductor Upgrade)** – Completed. Detailed variance explanation provided in TSP Schedule 2.9, Attachment 2.
- **T-SS-05 (Merivale TS: Add 230/115 kV Autotransformers)** – Completed.
- **T-SS-07 (West of Chatham Reinforcement)** – Completed.

Table 2 - Material HOSSM Investments

ISD	Investment Title
	System Access
T-SA-11	Customer Connections - Regulated Entities
	System Renewal
T-SR-03	Transmission Station Renewal - Connection Stations
T-SR-04	Wood Pole Structure Replacements
T-SR-09	Transmission Station Demand and Spares
T-SR-15	Transmission Line Emergency Restoration
	System Service
T-SS-11	Bulk Planning

T-SA-03	**HALTON TS: BUILD A SECOND 230/27.6KV STATION**
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	0.0	0.0	11.2	18.9	15.0	45.1

Summary:

This investment is required to facilitate a request from Milton Hydro to increase transformation capacity in the Town of Milton to accommodate forecasted customer load growth. The investment was included in Hydro One's 2023-2027 capital expenditure plan with a required in-service date of Q2 2027. Milton Hydro has deferred the required in-service date to Q4 2032.

The investment involves the construction of a new 230/27.6kV Dual Element Spot Network (DESN) station with two 75/125MVA transformers along with a new 27.6kV switchyard at the existing Halton TS site to provide the required increase in capacity at Halton TS.

Hydro One is obligated to expand facilities when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in inadequate transformation capacity to supply customer demand in the Town of Milton.

1.0 INVESTMENT NEED

This investment is required to facilitate a request from Milton Hydro to increase transformation capacity in the Town of Milton to accommodate forecasted customer load growth.

As identified in the IESO's 2024 GTA West Needs Assessment, Milton Hydro has forecasted nearly 80 MW of new load that exceeds the available capacity at Halton TS and a new station is an appropriate solution to supply the new load.[1]

The need to build a second 230/27.6kV station (Halton #2 TS) was initially forecasted to be required by the summer of 2022. This was identified in the 2nd cycle Regional Planning process in the Need Assessment and the Integrated Regional Resource Planning phases, which took place from 2019-2021. Following those studies, Milton Hydro provided a revised load forecast. It included provisions for new load to be supplied by Glenorchy MTS, and upsized Palermo TS, deferring the need for Halton #2 TS. The August 2024 GTA West Need Assessment Study, carried out under the regional planning process, reiterated the need for Halton #2 TS and identified a need date of 2026.

In the near term, Milton Hydro plans to use Oakville Hydro's Glenorchy MTS and upsized Palermo TS to meet the increasing demand before Halton TS #2 is available. Over the mid-term, this approach is insufficient to satisfy Milton Hydro's forecasted needs as demand continues to grow.

Hydro One is obligated to expand facilities when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in inadequate transformation capacity to supply customer demand in the Town of Milton.

[1] 3rd Cycle Need Assessment Report GTA West.pdf
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtawest/Documents/Needs-Assessment-GTA-West-2024.pdf

2.0 INVESTMENT DESCRIPTION

The investment involves the construction of a new 230/27.6kV DESN station with two 75/125MVA transformers along with a new 27.6kV switchyard at the existing Halton TS site. The new transformer station will be supplied by the existing 230kV transmission circuits (T38B/T39B), which also supply the existing Halton TS. This work will increase the existing capacity at Halton TS by approximately 170MVA.

The proposed investment is intended to provide relief solely for Milton Hydro load, as any increase in Halton Hills Hydro load is supplied from Halton Hills Hydro Municipal Transformer Station (MTS), which went into service in Q2 2019.

A map showing the project location is provided in Figure 1 below.

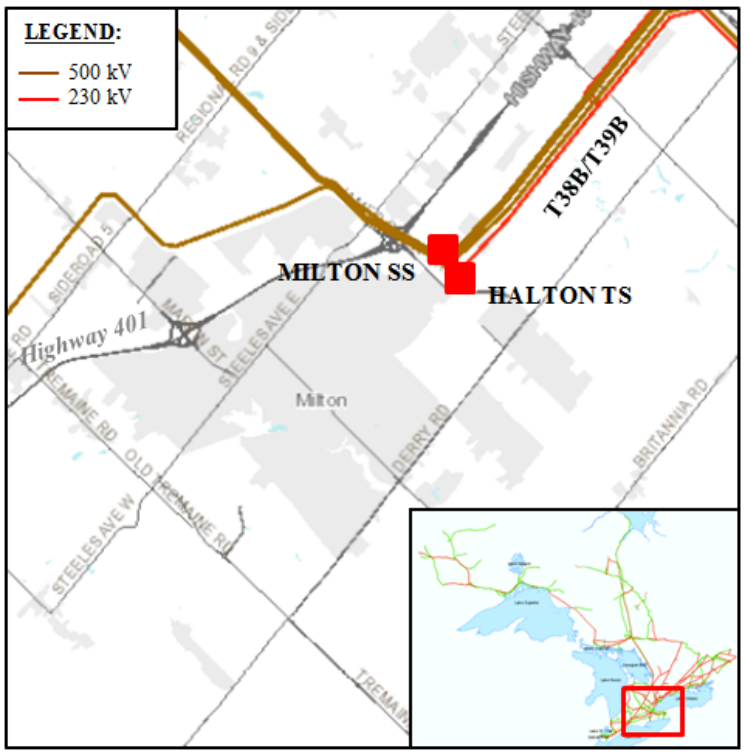

Figure 1: Second DESN to be added at Halton TS

The System Impact Assessment and Customer Impact Assessment are expected to be completed for the project by Q4 2026 to confirm that the project will not adversely affect

the reliability of the IESO-controlled grid or service to other transmission connected customers.

3.0 OUTCOMES

This investment will provide the transformation capability required to meet Milton Hydro's forecast customer load growth.

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Satisfy customer request for additional capacity.
Operational Effectiveness	• Increase capacity, and improve operational flexibility, with the addition of a second DESN.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

4.0 EXPENDITURE PLAN

This investment is non-discretionary as it is required to meet customer load growth. The project costs, as presented in Table 2 below, will be recoverable through incremental revenue from the appropriate rate pool and a capital contribution from the customer.

The investment costs are estimated based on best available information. Capital contribution amounts are estimated per Hydro One's Transmission Connection Procedure in accordance with the Transmission System Code. Project costs and capital contribution amounts are subject to true-up once the project is placed in-service, subject to the terms of a Connection Cost Recovery Agreement (CCRA).

Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One Investment Expenditures[2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	3.3	12.5	21.2	19.5	15.5	71.9
Less Removals	0.0	0.0	0.3	0.6	0.5	1.4
Less Capital Contributions	3.3	12.5	9.7	0.0	0.0	25.4
Net Capital Expenditures	**0.0**	**0.0**	**11.2**	**18.9**	**15.0**	**45.1**

Hydro One expects to place the investment in service in 2032 at a project total of $45.1M**.**

Although the investment was included in Hydro One's prior transmission rate application (EB-2021-0110), a customer-requested delay meant that no expenditures, planned or actual, are forecast for the 2023-2027 prior rate period. This is reflected in Hydro One's revised capital expenditure and ISA forecast, which implemented the OEB-approved Settlement Proposal in EB-2021-0110.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred investment.

ALTERNATIVE 1: STATUS QUO

The Status Quo alternative is not considered viable as it would not provide adequate transformation capacity to supply customer demand in the Town of Milton. Hydro One is obligated to provide expanded facilities when requested by customers in accordance with its Transmission License and the Transmission System Code.

ALTERNATIVE 2: TRANSFER LOADS TO OTHER AREA STATIONS

This alternative to transfer loads to other area stations was rejected because other nearby stations have insufficient capacity to provide Milton Hydro capacity needs in the mid-term. Other stations located further from the Milton Hydro load center were ruled out because of the challenges associated with arranging supply from a more distant station. These

[2] Figures presented in the tables may not sum to the totals shown due to rounding.

challenges include, but are not limited to, managing voltage performance and the need to secure additional right-of-way.

ALTERNATIVE 3: BUILD A SECOND DESN AT HALTON TS (RECOMMENDED)

The existing footprint of Halton TS has sufficient space to build the new facilities, and there is sufficient capacity on the existing 230kV lines at the station to supply the new transformer station.

Alternative 3 is the recommended alternative as it is the only practical alternative to provide the capacity needed beyond the mid-term. This recommended alternative is in accordance with the recommended plan in the August 2024 GTA West Needs Assessment for providing additional capacity to support the area's growth.

6.0 EXECUTION RISK AND MITIGATION

Hydro One does not anticipate any major execution risks. However, there is the potential for normal project risks that may affect the timely completion of the project, such as the availability of the outages required to execute the work and timely customer approval of the CCRA. These risks will be mitigated by working with the customer on setting a schedule that aligns with outage availability. There is also a risk that the customer requirements may change, resulting in a delay or cancellation of the need for this project. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer ultimately decides to cancel the project.

T-SA-05	**NEW & FUTURE TRANSMISSION LOAD CONNECTION PLANS**
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	10.0	10.0	25.0	32.0	33.0	110.0

Summary:

This investment is required to enable Hydro One to accommodate future requests from load customers to connect to Hydro One's transmission system where the need and scope have yet to be determined. The forecast amounts are not currently allocated to specific projects; however, it is necessary to maintain these unallocated connection amounts to enable Hydro One to respond to load customer requests that are expected to arise during the planning period but are currently unknown. The planned expenditures have been forecasted based on typical historical costs incurred for new load connections over the past five-year period, with near-term reduction to reflect a lower level of uncertainty.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code.

1.0 INVESTMENT NEED

This investment is required to enable Hydro One to accommodate future requests from load customers to connect to Hydro One's transmission system where the need and scope have yet to be determined. This investment anticipates load customer requests that are expected to arise during the test period but are currently unknown.[1] Customer connection activity has increased significantly during the 2023-2027 rate period, reflecting growing demand for access to the electricity system. As set out in TSP Section 2.8, in 2024, Hydro One managed approximately 97 customer connection projects. By the end of Q2 2026, the number has risen to 166 projects, representing an increase of more than 70%.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code.

2.0 INVESTMENT DESCRIPTION

This investment has been established to cover future load connection projects anticipated in the planning period where the need and scope have not yet been identified. Individual projects will be initiated based on the customers' requirements for capacity and/or reliability improvements or needs identified through regional planning.

Load customer connections are typically addressed by providing new or modified transformation and/or line connection facilities. Each investment will address specific customer needs. Based on past customer requests, the necessary investments may require Hydro One to construct one or more of the following:

- New feeder positions at existing transformer stations;
- New or modified transformation facilities at existing transformer stations;
- New connection lines; and/or
- New transformer stations.

[1] Hydro One's known load connections over the 2028-2032 period are provided as follows: customer connection projects for regulated entities are provided in TSP Section 2.12, T-SA-03, T-SA-08, SA-09, SA-10 and T-SA-11, while non-regulated customer connection projects are provided in TSP Section 2.12, T-SA-12.

Commencement of each project will be subject to signing a Connection Cost Recovery Agreement (CCRA) with the customer and obtaining all necessary regulatory and environmental approvals.

3.0 OUTCOMES

This investment will address specific customer requests for connection or transformation capacity to supply the customers' forecasted load growth or address other customer connection needs.

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Satisfy customer requests for connection, increased capacity, improved reliability or power quality.
Operational Effectiveness	• Investments may also provide increased operational effectiveness.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.

4.0 EXPENDITURE PLAN

This investment is non-discretionary. The investment covers multiple future load connection projects for which the need and scope have not yet been defined. As such, the forecast amounts are not currently allocated to specific projects; however, it is necessary to maintain these unallocated connection amounts because load connection projects materialize during the planning period, and this investment enables Hydro One to respond to customer requests in a timely manner once connection requirements are identified.

Individual project costs will be recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customer(s), determined on a project-by-project basis as per Hydro One's Transmission Connection Procedure in accordance with the Transmission System Code. Investment costs are estimated based

on typical historical costs incurred. Project costs and capital contribution amounts are subject to true-up once the project is placed in-service, subject to the terms of the CCRA.

The projects' actual in-service costs would be included in the rate base when the projects go in service, subject to OEB approval. For any projects that require Leave to Construct approval under Section 92 of the *Ontario Energy Board Act, 1998.*, the proposed expenditures will be tested during the Section 92 process.

Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One - Investment Expenditure

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	33.3	33.3	83.3	106.7	110.0	366.6
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	23.3	23.3	58.3	74.7	77.0	256.6
Net Capital Expenditures	**10.0**	**10.0**	**25.0**	**32.0**	**33.0**	**110.0**

In developing the estimated net capital expenditures, historical net actual cost for load connection projects in the past 5 years (~$30.0M annually) was used as a basis for the 2028 forecast. Based on the IESO's 2026 Annual Planning Outlook's compounded annual load growth rate, a growth factor of 1.5% was applied on an annual basis out to 2032 to align with provincial load growth forecast as a result of broader electrification.

As Hydro One expects greater project certainty in the near term (2028-2030), the net amounts in 2028, 2029 and 2030 are reduced to reflect a lower risk of unknowns. Capital contributions from these future projects are estimated on the assumption that future unknown projects will likely be triggered by customers with shorter economic evaluation periods, such as an industrial customer, as the majority of local distribution customers would have signaled new connections early or through the regional planning process. Due to the shorter economic evaluation period, Hydro One estimates about two-thirds of the gross capital will be covered by customer capital contribution.

5.0 ALTERNATIVES

This investment will be in response to a specific customer(s) request received in the future; alternatives (if any) will be reviewed with the customer(s) as part of the connection assessment process.

6.0 EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, the potential exists for normal project risks that may affect the timely completion of the project, such as availability of outages required for the work to be executed and timely customer approval of the CCRA. These risks will be mitigated by working with the customer on setting a schedule that aligns with outage availability. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer ultimately decides to cancel the project.

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T-SA-06	**PROTECTION AND CONTROL MODIFICATIONS FOR DISTRIBUTED ENERGY RESOURCES**
Primary Trigger:	Customer Request, Reliability
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	0.0	0.0	0.0	0.0	0.0	0.0

Summary:

This investment is needed to upgrade protection and control capabilities on Hydro One's transmission system to accommodate the connection of distributed energy resources (DERs) on local distribution company (LDC) distribution systems. The DERs are generation facilities, including energy storage systems, which connect to the distribution system. These connections may require modifications to the upstream transmission protection system to maintain safe and reliable operation of the distribution and transmission systems.

Where DER connections on distribution systems create upstream transmission impacts, Hydro One is required to take the measures necessary to preserve reliability and performance of the transmission system in accordance with applicable statutory, licence, Market Rules, and OEB code requirements. Not proceeding with this investment would result in new DERs not being able to connect.

1.0 INVESTMENT NEED

This investment is needed to perform required protection and control upgrades on the Hydro One transmission system to accommodate the connections of distributed energy resources on local distribution company distribution systems. The DERs are generation facilities, including energy storage systems, which connect to the distribution system and these connections may require modifications to upstream transmission protection systems to maintain safe and reliable operation of the distribution and transmission systems.

Where DER connections on distribution systems create upstream transmission impacts, Hydro One is required to take the measures necessary to preserve reliability and performance of the transmission system in accordance with applicable statutory, licence, Market Rules and OEB code requirements. Not proceeding with this investment would result in new DERs not being able to connect.

2.0 INVESTMENT DESCRIPTION

Following the conclusion of the Feed-in Tariff (FIT) program in 2018, distributed energy resource 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.

In 2023, the IESO launched the Expedited Long Term Request for Proposals (ELT1 RFP) and Long Term 1 (LT1 RFP), under which approximately 52 MW of DER have been connected or are in the execution phase for connection at the distribution system level. In 2026, the IESO completed their review of submissions under the Long Term 2 Request for Proposals (LT2 RFP) Window-1. Six successful applicants have received contracts for a total of 85 MW with target in-service by the end of 2029.

To accommodate the connection of DERs at the distribution system level, Hydro One's transmission system requires protection and control system modifications and additions in transmission stations to ensure proper protection of transmission assets, reliability of supply to the distribution systems, and safe interconnection. All the transmission costs

required for connecting new DERs to LDC distribution systems are 100% recoverable from DER customers.

This investment addresses protection and control modifications and additions such as:

- Feeder protection replacement to preserve the protection capability of the feeders and to provide directioning to prevent false tripping;
- Bus protection modification to prevent mis-operation;
- Line back-up protection installation to protect transmission assets from DERs' fault current contribution;
- Transfer trip signalling installation to prevent DER islanding and to coordinate with reclosing and restoration;
- Station telecom facilities installation to enable transfer trip signalling; and
- Station telemetry expansion to provide feeder telemetry and additional equipment alarms.

Commencement of each DER connection under this investment is subject to the signing of a Connection Cost Recovery Agreement (CCRA) with the customer(s).

3.0 OUTCOMES

This investment will allow the required connection of DERs throughout Ontario to occur without compromising system reliability by maintaining proper protection and loading capability of Hydro One's transmission assets.

3.1 OEB RRF OUTCOMES

Table 1 below presents anticipated benefits as a result of the Investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Support DER connections to distribution systems.
Operational Effectiveness	• Preserve the loading and protection capability of the transmission system while incorporating DERs.
Public Policy Responsiveness	• Comply with Hydro One's obligation where DER connections on distribution systems create upstream transmission impacts, to take the measures necessary to preserve reliability and performance of the transmission system in accordance with its Transmission Licence and applicable statutory, Market Rules and OEB code requirements.

4.0 EXPENDITURE PLAN

This investment is non-discretionary. The program expenditures, as presented in the table below, will be fully recoverable through capital contributions from the customers. Gross expenditures have been forecasted based on current DER customer requests and anticipated future requests resulting from the IESO Industrial Conservation Initiative (ICI) and Long Term RFP (ELT1, LT1 & LT2) programs. The capital contribution amounts are estimated per Hydro One's Connection Procedures in accordance with the Transmission System Code, subject to the terms of a CCRA.

Table 2 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	5.1	5.1	5.1	5.1	5.1	25.3
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	5.1	5.1	5.1	5.1	5.1	25.3
Net Capital Expenditures	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.

5.0 ALTERNATIVES

No alternatives were considered, as failing to implement the protection and control modifications and additions would result in the inability to respond to connection requests. Required modifications will be determined on the basis of each request and connections will only be made where the necessary modification can be performed.

6.0 EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal investment risks that may affect the timely completion of the investment, such as outage availability to execute the work and timely customer approval of the CCRA. These risks are mitigated by working with customers on setting a schedule that aligns with outage availability. The CCRA will allow Hydro One to recover the actual costs incurred even if customers ultimately decide to cancel the investment.

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T-SA-07	COMPATIBLE LAND USE PROJECTS
Primary Trigger:	Mandated Obligations
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	45.9	47.7	49.3	54.7	42.0	239.6

Summary:

This investment involves the relocation or modification of existing transmission assets to accommodate third-party development projects because the transmission assets conflict with proposed third-party infrastructure. The primary triggers for the investments are Hydro One's obligations to address external third-party requests. The costs of these investments are recoverable from third parties in most situations except certain cases where the relocation work is non-recoverable based on legal or property rights considerations. This ISD outlines the material investments required due to third-party requests and indicates the cost recovery plan of each one. Two investments outlined in this ISD are continued projects from the previous Hydro One transmission revenue requirement application for the 2023-2027 period and are noted as such in Table 1 below.

These investments are required to allow Hydro One to meet its obligations to accommodate development work by Provincial proponents and other third parties while also maintaining reliability and public safety with respect to the siting and operations of affected Hydro One transmission assets.

1.0 INVESTMENT NEED

This investment is required to respond to third-party requests for the relocation, removal, or reinforcement of transmission assets in response to project proposals, such as roadwork, transit systems development, and other major infrastructure or development work that may encroach upon or impact Hydro One assets and rights-of-way.

Hydro One's transmission corridors span lands with diverse ownership including, but not limited to, Provincial, private, Crown and Hydro One-owned. In certain locations it is not possible to accommodate certain proposed third-party land uses without relocating or modifying Hydro One assets. This investment is required to fund these relocations and modifications.

2.0 INVESTMENT DESCRIPTION

The proposed investment involves accommodating third-party requests to utilize Hydro One's transmission corridors for compatible land use purposes where there is conflict between the proposals and existing Hydro One assets. Hydro One may require additional or modified land rights to accommodate these requests. In such cases, the proponents will acquire the additional land rights at their cost on Hydro One's behalf.

The material investments forecast over the 2028-2032 period, including the estimated gross costs and details relating to each identified investment, are outlined in Table 1 below. Due to circumstances specific to each investment, the associated costs may not be fully recoverable from third-party proponents. The most common investment drivers are municipal and regional transit planning, highway and road expansions, and development projects adjacent to or crossing Hydro One's transmission corridors.

1 **Table 1 - List of Material Investments**

No	Project Name	Description	Total Gross Project Total ($M)
1	**West Toronto Transmission Line Relocation** *Proponent: Metrolinx*	Metrolinx is proceeding with infrastructure upgrades along its Barrie Rail Corridor as part of the GO Expansion program. A section of the Hydro One double-circuit line K1W/K3W is located within the rail corridor between Eglinton Avenue West and St. Clair Avenue West in Toronto. To accommodate Metrolinx's planned development, Hydro One must relocate the 115kV double-circuit line. Hydro One and Metrolinx jointly determined to proceed with an underground tunnel solution. Under an existing real estate licence agreement with Metrolinx, Hydro One is contractually obligated to fund 85% of the project cost while Metrolinx is responsible for the remaining 15%. The licence agreement was entered into in 1997 by the former Ontario Hydro and the Canadian National Railway Company (CN Rail). Following Ontario Hydro's restructuring in 1999, Hydro One assumed Ontario Hydro's rights and obligations under the agreement. Metrolinx subsequently acquired the rail corridor and assumed CN Rail's corresponding rights and obligations. Hydro One exercised a licence renewal option in 2018. This investment was previously included in Hydro One's last transmission application for the 2023-2027 period (EB-2021-0110). However, due to project scope development, the in-service date was extended to the 2028-2032 rate period. Hydro One expects to place the investment in service in Q4 2032. The expected net Project Total is $276.4M. The in-service date is subject to Metrolinx's commitments and project progress.	**325.2**

2	**MTO – Highway 401 and Highway 6 Expansion** *Proponent: MTO*	The MTO is proposing to construct a new Highway 401 and Highway 6 South/West Interchange. Hydro One has two 500 kV transmission circuits (M585M and V586M) that cross Highway 401 in the vicinity of the proposed South/West Interchange. To accommodate this proposal, Hydro One needs to replace one of its transmission structures with a taller tower to maintain proper safety clearances. This investment was previously included in Hydro One's last transmission application for the 2023-2027 period (EB-2021-0110), however, due to delays by the MTO, the in-service date has been extended into the 2028-2032 planning period. The capital costs associated with this investment are 100% recoverable from the MTO. The expected in-service date for this investment is Q4 2028, which is subject to the MTO's commitments and subject to further delays if not achieved on time.	**5.6**
3	**Transmission Line Relocation**	A proponent is proposing an expansion of its site, which will require Hydro One to relocate a section of its existing 500kV transmission circuit D501P to a new alignment The capital costs associated with this investment are 100% recoverable from the Proponent. The expected in-service date for this investment is Q3 2031, which is subject to Proponent's commitments and subject to further delays if not achieved on time.	**97.9**
4	**MTO Highway 6 South Widening from Hwy 403-James St** *Proponent: MTO*	The MTO is proposing the widening of Highway 6 South, a new interchange, and intersection improvements in the City of Hamilton. To accommodate this project, Hydro One needs to modify/relocate existing 230kV transmission circuits M27B/M28B, Q24HM/Q29HM, M34H, Q23BM/Q25BM to maintain proper safety clearances. The capital costs associated with this investment are 100% recoverable from the MTO. The expected in-service date for this investment is Q4 2029, which is subject to the MTO's commitments and subject to further delays if not achieved on time.	**7.0**

5	**Whites Road Realignment- Phase 1** *Proponent: Regional Municipality of Durham*	The Regional Municipality of Durham is proposing the realignment of Whites Road between Finch Avenue and Taunton Road in Pickering, which will include constructing a high bridge to cross West Duffins Creek. This project will require modification/relocation of Hydro One's existing 230 kV transmission circuit C10A to maintain proper safety clearance. The capital costs associated with this investment are 100% recoverable from the Regional Municipality of Durham. The expected in-service date for this investment is Q3 2028, which is subject to the Regional Municipality of Durham's commitments and subject to further delays if not achieved on time.	**11.4**
6	**TTC Western Yard** *Proponent: TTC*	The Toronto Transit Commission (TTC) is proposing to construct a new subway maintenance and storage facility adjacent to Kipling Subway Station in Toronto. This project will require modification and/or relocation of Hydro One's existing 230 kV transmission circuits – R1K/R2K to maintain proper safety clearance. The capital costs associated with this investment are 100% recoverable from the TTC. The expected in-service date for this investment is Q2 2028, which is subject to the TTC's commitments and subject to further delays if not achieved on time.	**4.6**
7	**Transmission Line Relocation**	A Proponent is proposing to construct a new road. As a result of this project, Hydro One will be required to modify/relocate its existing 115 kV and 230 kV transmission circuits – S2B, S22A and X27A to maintain proper safety clearance. The capital costs associated with this investment are 100% recoverable from the Proponent. The expected in-service date for this investment is Q3 2028, which is subject to Proponent's commitments and subject to further delays if not achieved on time.	**3.7**

**Note: The Total Gross includes the total cost of the project, including any costs prior to the test years, if applicable.*

3.0 OUTCOMES

These investments will allow Hydro One to fulfill its obligations to accommodate the development work of provincial proponents and other third parties while also ensuring that reliability and public safety are maintained with respect to the siting and operations of affected Hydro One transmission assets.

3.1 OEB RRF OUTCOMES

Table 2 below presents anticipated benefits as a result of the Investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 2 - Outcome Summary

Customer Focus	• Satisfy the proposed project-related requirements of proponents and third parties.
Operational Effectiveness	• Maintain sufficient clearance to Hydro One transmission assets to ensure reliability and public safety.
Public Policy Responsiveness	• Support provincial policies on transit development as well as compatible land uses on Hydro One transmission corridors through the relocation and modification of transmission facilities to accommodate compatible uses that conflict with existing transmission assets.

4.0 EXPENDITURE PLAN

Table 3 below summarizes forecast capital expenditures for the 2028-2032 rate period. The investment costs, as presented in the table below, are typically recoverable through capital contributions from the proponents; however, one investment (West Toronto Transmission Line Relocation) outlined in Table 1 above presents a unique situation where Hydro One is responsible for significant portions of the investment cost. The size and complexity of these investments vary from year to year, and the planned investment cost is based on preliminary estimates for the investments, which are in various stages of development.

Table 3 - Hydro One - Investment Expenditures[1,2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	88.2	82.9	81.7	88.1	49.4	390.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	42.3	35.2	32.4	33.4	7.4	150.7
Net Capital Expenditures	**45.9**	**47.7**	**49.3**	**54.7**	**42.0**	**239.6**

Table 4 includes the prior project total and current project total for the West Toronto Transmission Line Relocation, which is the only material investment under this ISD. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The maturity of the project at the time of filing is presented in Table 4 below, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

Table 4 - Hydro One – Material Investment Net Expenditures

Investment Name	Prior Type	Prior Proj. Total[3]	Prior In-Service Year	Type	Proj. Total	In-Service Year
West Toronto Transmission Line Relocation	P	56.8	2029	P	276.4	2032

The variance for the West Toronto Transmission Line Relocation is primarily attributable to a significant scope change, jointly determined by Hydro One and Metrolinx, to proceed with a tunnel solution. This approach was selected to meet schedule commitments to Metrolinx and address the space constraints associated with the existing circuits' location in a dense urban area. An open-cut solution was not preferred because it would require extensive third-party utility clearances, permits, and other approvals, increasing execution complexity and schedule risk. Hydro One expects to incur $41.0M prior to 2028 and $235.3M during the 2028-2032 period for this project.

[1] Forecast net capital expenditures for the 2028-2032 period include $4.3M of immaterial investments.
[2] Figures presented in the tables may not sum to the totals shown due to rounding.
[3] "Prior Proj. Total" refers to the project total related to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

As proposed in Exhibit G-01-03 Section 3.1, the Externally Driven Transmission Projects Variance Account will record the revenue requirement impact of variances between the in-service additions embedded in Hydro One's approved revenue requirement relating to this investment and the actual in-service additions for this investment over the 2028-2032 period.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

The status quo is not an option as Hydro One's assets are in conflict with proponents' proposed developments. Often these conflicts involve ensuring that Hydro One's facilities have sufficient safety clearances to adjacent infrastructure once the proposed developments are completed. As a result, not proceeding with this work could subject Hydro One employees to unsafe working conditions. For third-party uses that contemplate public infrastructure, such as roads, these conflicts could pose safety risks to the general public. Furthermore, not proceeding with these investments would prevent proponents, such as municipalities and transit and road authorities, from executing their planned projects, which include significant public infrastructure.

ALTERNATIVE 2: PROCEED WITH PROPOSED INVESTMENTS (RECOMMENDED)

Hydro One works with third parties that propose land uses and assesses whether the proposals are technically compatible with the safe and reliable operation of Hydro One's transmission infrastructure. Some proposals may be deemed to be incompatible and thus would not proceed. For those proposals that are compatible, and require relocation or modification of Hydro One assets, no alternatives are considered, as these investments are required to respond to specific proponent and third-party requests. However, each investment is scoped, planned, and executed to provide the lowest cost relocation or modification possible, given the nature of existing infrastructure.

6.0 EXECUTION RISK AND MITIGATION

Certain normal project execution risks may affect the timely completion of each investment, such as the availability of outages required for the work to be executed, delays in obtaining environmental or regulatory approvals, and timely proponent execution of capital cost recovery agreement(s). These risks will be mitigated by working with proponents to establish a schedule that considers these constraints. These investments are also demand-driven and susceptible to delays, cancellations, and scope changes driven by external factors that are beyond Hydro One's control.

Hydro One may require additional or modified land rights to accommodate the modified transmission assets. In these cases, the proponents will be required to acquire the additional land rights on Hydro One's behalf. Ongoing coordination and engagement, as well as structured capital cost recovery agreements, mitigate the risk of investment uncertainty in the event of scope changes or cancellation. The capital cost recovery agreement(s) will allow Hydro One to recover the actual costs incurred even if the proponent ultimately decides to cancel its project.

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T-SA-08	**H29/H30: RECONDUCTOR 230KV CIRCUITS**
Primary Trigger:	Regional Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	10.4	4.9	0.0	0.0	0.0	15.3

Summary:

This investment is required to upgrade the 230kV double circuit line H29/H30 supplying Pleasant Transformer Station (TS) to meet forecast load growth. The investment was included in Hydro One's 2023-2027 capital expenditure plan, with an in-service date of Q2 2027. In 2025, Alectra Utilities Corporation (Alectra) requested a further capacity increase, which extended the in-service date to Q2 2029.

The upgrade work covers replacing the existing line conductor with a higher current-rated conductor to provide sufficient thermal capacity. The investment is expected to meet capacity need due to forecasted load growth and improve operational effectiveness by providing sufficient transmission capacity.

Hydro One is obligated to provide or expand facilities when requested by customers and as required to meet load growth in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in inadequate transmission capacity to supply the forecast Pleasant TS load.

1.0 INVESTMENT NEED

The investment will facilitate satisfying the forecast load increase in the area as documented in the 2022 GTA West Regional Infrastructure Plan[1] and the 2024 Needs Assessment for GTA West.[2]

The in-service date for this investment has shifted from Q2 2027 to Q2 2029. The 2022 GTA West Regional Infrastructure Plan indicated that the line capacity is expected to be exceeded by 2027. A subsequent Hydro One Distribution load forecast adjustment supported deferral of the need to 2028. Thereafter, Alectra requested an additional capacity increase, which extended the in-service date to Q2 2029. In the interim, line capacity will be managed at the operational level.

Hydro One is obligated to provide or expand facilities when requested by customers and as required to meet load growth in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in inadequate transmission capacity to supply the forecast Pleasant TS load.

2.0 INVESTMENT DESCRIPTION

This investment involves the upgrading of the 8.5km long 230kV double circuit line H29/H30 between Hurontario SS and Pleasant TS. The upgrading work covers the replacement of the existing conductor with a higher current-rated conductor. Figure 1 shows the routing of the circuits.

The upgraded line will provide adequate capability to fully meet the need and will enable loading of the step-down transformer facilities at Pleasant TS to their maximum rated capacity.

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[1] GTA West Regional Infrastructure Plan, February 23, 2022, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtawest/Documents/RIP-Report-GTA-West-2022.pdf

[2] Needs Assessment Report, GTA West, August 30, 2024, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtawest/Documents/Needs-Assessment-GTA-West-2024.pdf

A map of the location is presented in Figure 1 below.

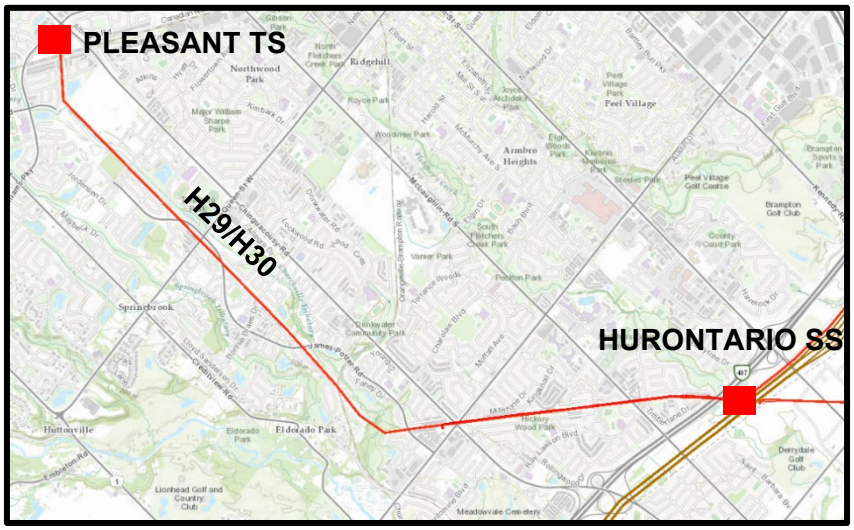

Figure 1: Radial Circuits of H29/H30 Supplying Pleasant TS

The System Impact Assessment and Customer Impact Assessment have been completed and confirmed that the project is not expected to adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

3.0 OUTCOMES

This investment will provide adequate capacity to meet forecast load growth at Pleasant TS.

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the Investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Ensure adequate capacity to supply Pleasant TS loads
Operational Effectiveness	• Improve operational flexibility as a result of increase in capacity
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to expand the transmission system to support load growth

4.0 EXPENDITURE PLAN

This investment is non-discretionary as it is required to meet customer load growth. The investment costs, as presented in Table 2 below, will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers.

The investment costs are estimated based on best available information. Capital contribution amounts are estimated pursuant to Hydro One's Transmission Connection Procedures in accordance with the Transmission System Code. Capital contribution amounts are expected to be received prior to 2028 for this investment. Project costs and capital contribution amounts are subject to true-up once the project is placed in-service, subject to the terms of the Connection and Cost Recovery Agreement (CCRA). Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One – Investment Expenditures[3]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	11.2	5.2	0.0	0.0	0.0	16.4
Less Removals	0.8	0.4	0.0	0.0	0.0	1.2
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**10.4**	**4.9**	**0.0**	**0.0**	**0.0**	**15.3**

Table 3 below includes the prior project total, current project total, as well as the maturity of the project at the time of filing, where Execution (E) reflects fully approved project work

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

Table 3 - Hydro One – Material Investment Net Expenditures

Investment Name	Prior Type	Prior Proj. Total[4]	Prior In-Service Year	Type	Proj. Total	In-Service Year
H29/H30: Reconductor 230kV Circuits	P	6.0	2027	E	24.0	2029

This investment is expected to be placed in service in 2029 at a forecast project total of $24.0M net. In 2024, Hydro One began the project cost estimate and long lead-time material procurement and expects to incur $8.7M prior to 2028. For the 2028-2032 period, Hydro One expects the project total to be $18.0M higher than the prior project total due to the following:

- Higher and sustained inflationary pressures experienced by Hydro One during the 2023-2027 period relative to the inflation assumptions embedded in its last transmission application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historic material cost escalation trends are described in SPF Section 1.8.3, including conductors, cables and wires, which have increased by 65% on average since 2020.
- Capital contributions have decreased to $1.1M due to the increased load forecast.

The in-service year changed from 2027 to 2029 due to the additional capacity request from Alectra discussed above.

[4] "Prior Proj. Total" refers to the Project Total related to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

Hydro One is obligated to provide or expand facilities, as required, to meet load growth in accordance with its Transmission License and the Transmission System Code. The Status Quo alternative is not viable as it does not provide adequate transmission capacity to supply the load demand at Pleasant TS.

ALTERNATIVE 2: UPGRADE LINE CONDUCTOR (RECOMMENDED)

This alternative covers upgrading the line by replacing the existing conductor with a conductor having a higher current rating. The 2022 GTA RIP and the 2024 Needs Assessment both have identified this as the most effective solution to address the capacity limitation.

6.0 EXECUTION RISK AND MITIGATION

The risks associated with the execution of this investment as planned arise from potential delays in securing the Section 92 approval. These risks will be mitigated by initiating the Section 92 application process in a timely manner.

Normal project risks that may also affect the timely completion of the investment include the availability of outages required for the work to be executed while maintaining supply to Pleasant TS. These risks will be mitigated by setting a schedule that aligns with outage availability.

T-SA-09	**NEW TRANSFORMER STATION IN NORTHERN YORK REGION**
Primary Trigger:	Regional Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	7.3	19.7	25.0	-5.4	0.0	46.6

Summary:

This investment involves building a new 230/44 kV load-serving station in Northern York Region. The primary trigger for the investment is the need for additional transformation capacity to meet area load growth, as the capacity of existing area stations is expected to be exceeded by 2027. This need is confirmed in the latest Greater Toronto Area (GTA) North Regional Planning reports, including the Integrated Regional Resource Plan (IRRP) issued October 2025 and the Regional Infrastructure Plan (RIP) issued May 2026. The planned in-service date of this station is Q4 2031.

Hydro One is obligated to provide facilities as required to meet load growth in accordance with its Transmission Licence and the Transmission System Code. Not proceeding with this investment would result in inadequate transformation capacity to supply projected customer demand in the area.

1.0 INVESTMENT NEED

Northern York Region is supplied by two 230/44 kV transformer stations, Armitage TS and Holland TS. It is also partially supplied by Brown Hill TS. Based on the current load forecast, by 2027 the loading at Armitage TS and Holland TS will exceed their combined capacity of 485 MW. This investment is required to increase the transformation capacity to accommodate the forecasted customer load growth in the Northern York Region, as documented in the GTA North RIP.[1] This investment was originally expected to be placed in-service in 2027 but was delayed by the customer. The station has a planned in-service date of Q4 2031. During the period between 2027 and 2031, Hydro One will work with the customer to support, where feasible, load transfers or other operational measures identified by the customer to manage loading until the new station is placed in service.

Hydro One is obligated to provide facilities as required to meet load growth in accordance with its Transmission Licence and the Transmission System Code. Not proceeding with this investment would result in inadequate transformation capacity to supply projected customer demand in the area.

2.0 INVESTMENT DESCRIPTION

The investment involves the construction of a new 230/44 kV Dual Element Spot Network (DESN) station with two 75/125 MVA transformers along with a new 44 kV switchyard at a new site pursuant to the recommendation in the GTA North RIP. The new transformer station will be supplied by 230 kV transmission circuits H82V/H83V which run between Holland TS and Claireville TS. This work will increase the transformation capacity in Northern York Region by approximately 150 MW.

[1] Regional Infrastructure Plan Report, GTA North, dated May 6, 2026, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/GTA-North-RIP-May-2026.pdf

A map showing the project location is provided in Figure 1 below.

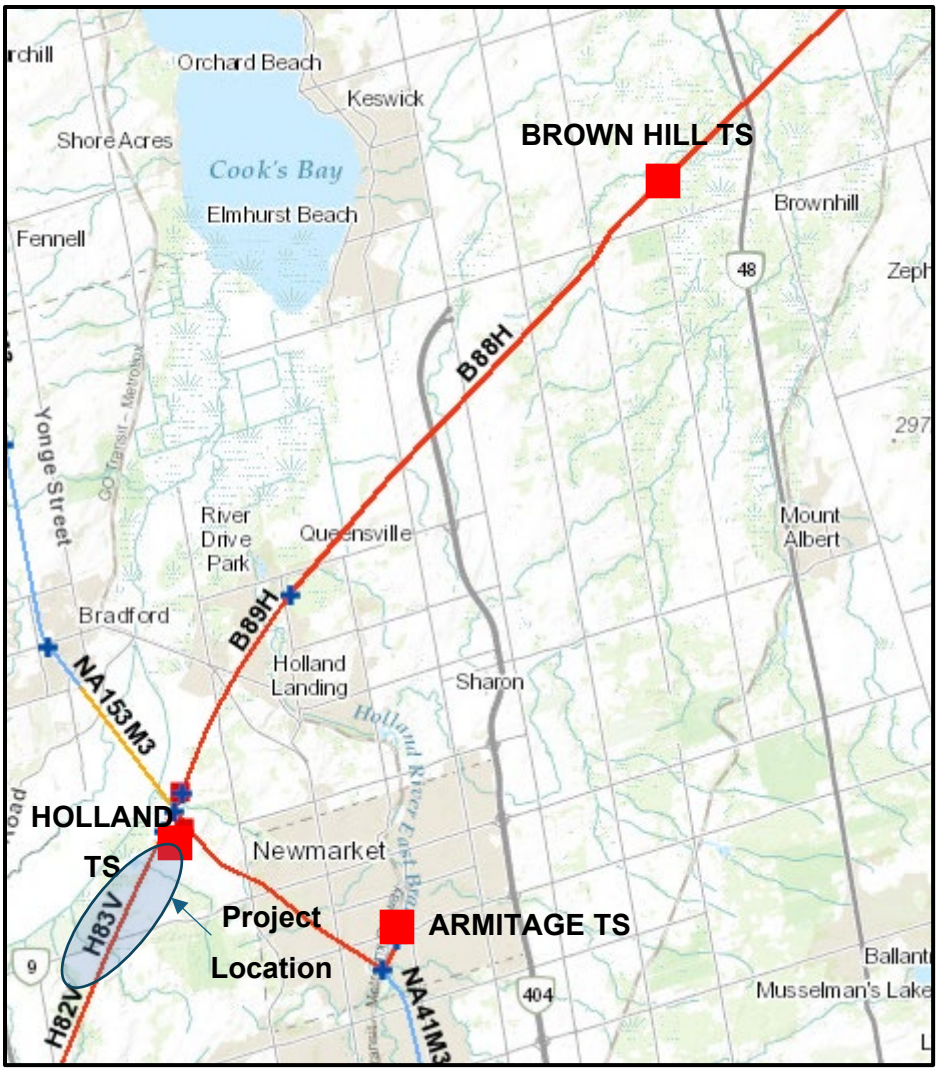

Figure 1: Proposed New Station Location

The System Impact Assessment and Customer Impact Assessment are expected to be completed for the project by Q1 2028 to confirm that it will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

3.0 OUTCOMES

This investment will provide the additional transformation capacity required to accommodate forecast load growth in Northern York Region.

3.1 OEB RRF OUTCOMES

Table 1 below presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcome Summary

Customer Focus	• Satisfy customer need for additional transformation capacity
Operational Effectiveness	• Increase transformation capacity and improve operational flexibility with the addition of a new station.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence to provide customers with non-discriminatory access.

4.0 EXPENDITURE PLAN

This investment is non-discretionary because it is required to meet forecasted customer load growth in the Northern York Region. The project expenditures, as presented in the table below, will be fully recoverable through incremental revenue from the appropriate rate pool and capital contributions from customers.

The investment costs are forecasted based on best available information. Capital contribution amounts are estimated per Hydro One's Transmission Connection Procedures in accordance with the Transmission System Code. Project costs and capital contribution amounts are subject to true-up once the project is placed in-service, subject to the terms of the Connection Cost Recovery Agreement (CCRA) with Hydro One Distribution.

Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 rate period.

Table 2 - Hydro One - Investment Expenditures[2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	7.3	19.7	25.0	12.2	0.0	64.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	0.0	0.0	0.0	17.6	0.0	17.6
Net Capital Expenditures	**7.3**	**19.7**	**25.0**	**-5.4**	**0.0**	**46.6**

Table 3 below includes the prior project total, current project total, as well as the maturity of the project at the time of filing, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

Table 3 - Hydro One - Rate Period Net Investment Expenditures

Investment Name	Prior Proj. Phase	Prior Proj. Total[3]	Prior In-Service Year	Proj. Phase	Proj. Total	In-Service Year
New Transformer Station In Northern York Region	P	13.2	2027	P	48.4	2031

This investment is expected to be placed in-service in 2031 at a forecast project total of $48.4M net. The forecast project total includes $1.8M of expenditures prior to 2028 and $46.6M of net capital expenditures during the 2028–2032 rate period.

Hydro One expects the project total to be approximately $35M higher than the prior project total of $13.2M primarily due to higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its last transmission application (EB-2021-0110), as described in SPF 1.8. Neither the inflation assumptions in

[2] Figures presented in the tables may not sum to the totals shown due to rounding.
[3] "Prior Proj. Total" refers to the project total related to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

the last transmission application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Additionally, the capital contribution was reduced by $8M due to an increase in load forecast as detailed in the 2025 IRRP[4] along with consideration for the revised in-service timeline, resulting in a corresponding $8M increase in net project cost.

The in-service date for the station was delayed from 2027 to 2031 due to customer delay.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

This is a non-discretionary investment and therefore the status quo is not a feasible alternative. Failure to undertake this investment would lead to insufficient transformation capacity to supply customer load growth, which would violate the conditions of Hydro One's Transmission Licence.

ALTERNATIVE 2: SUPPLY LOAD GROWTH FROM BROWN HILL TS

Due to the more than 20 km distance between Brown Hill TS and the Armitage TS and Holland TS service territory, Brown Hill TS is not a suitable facility for transferring excess load without incurring significant distribution costs. This alternative would be more expensive as one or more longer distribution feeders would be needed and is therefore not recommended.

ALTERNATIVE 3: BUILD NEW TRANSFORMER STATION IN NORTHERN YORK REGION (RECOMMENDED)

[4] GTA North (York Region) Integrated Regional Resource Plan, dated October 10, 2025, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/York/gta-north-York-IRRP-Report.pdf

This alternative involves building a new transformer station at a new site in Northern York Region, including the acquisition of a new site and the connection of the station to existing 230 kV lines, as discussed above.

Alternative 3 is the recommended and only practical alternative to provide the required capacity. Hydro One will work with the area LDCs to determine a suitable site.

6.0 EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the project, such as availability of the outages required for the work to be executed. These risks will be mitigated by working with the area customer to develop a schedule that aligns with outage availability. There is also a risk that the area customers' requirements may change, resulting in a delay or cancellation of the need for this project. The CCRA will allow Hydro One to recover the actual costs incurred even if the project is ultimately delayed or cancelled.

1 This page has been left blank intentionally.

T-SA-10	BUILD LEAMINGTON AREA TRANSFORMER STATIONS AND LINE
Primary Trigger:	Customer Request, Regional Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	29.8	65.3	95.0	115.0	-13.7	291.3

Summary:

This investment involves the construction of the remaining two of three Dual Element Spot Network (DESN) stations and an approximately 27 km 230kV double circuit transmission line in the Kingsville – Leamington area. The first DESN station was completed and placed in service in Q1 2025.

The investment will increase station capacity and area supply capacity to accommodate customer load connection needs and support load restoration in the event of an outage. The primary triggers of the investment are area load growth supported by customer requests and the need for broader supply capacity along with load restoration needs to meet the requirements under the Ontario Resource and Transmission Assessment Criteria (ORTAC).

Stage 1 of this project, South Middle Road TS (also known as Leamington #4 DESN) has been completed and was placed in-service in Q1 2025. Stages 2 and 3 of the project were put on hold at customer request. Following the recommendation of the 2025 Windsor-Essex Integrated Regional Resource Plan (2025 Windsor-Essex IRRP), Stages 2 and 3 have now restarted. The report also recommended that the new supply lines be tapped off the planned Lakeshore x Lauzon TS double circuit 230kV line instead of the existing circuits into Lakeshore TS in addition to constructing a restoration link back to the Leamington TS supply circuits to support load restoration. The planned in-service date for Stages 2 and 3 is Q4 2032.

Hydro One is obligated to connect customers and to provide facilities as required to meet load growth in accordance with its Transmission Licence and the Transmission System Code (TSC). Not proceeding with this investment would result in inadequate transmission capacity to connect new customers or supply the forecast area loads.

1.0 INVESTMENT NEED

This investment is required to increase station capacity, load supply capability, and load restoration in the Kingsville - Leamington area, a sub-region of Windsor – Essex. Hydro One Distribution has received a substantial increase in requests for load connections in the Kingsville - Leamington area driven by expansion in the agricultural and greenhouse sector coupled with their large uptake of energy intensive grow lights. The unprecedented growth in demand in this area is noted in the 2025 Windsor – Essex Integrated Regional Resource Planning (IRRP) studies and bulk system planning studies by the IESO.[1] The 2025 Windsor-Essex RIP, completed between 2023-2025 has further identified regional infrastructure needs to support the continued growth in the region and load restoration during an outage per ORTAC requirements.[2]

Hydro One is obligated under its Transmission Licence and the TSC to accommodate connections when requested by customers. Not proceeding with this investment would directly and adversely impact Hydro One's ongoing capability to reliably supply customer need in this area.

2.0 INVESTMENT DESCRIPTION

This project encompasses the construction of three DESN stations and an approximately 27 km 230 kV double circuit transmission line in the Kingsville – Leamington area. Stage 1 of this project, South Middle Road TS (also known as Leamington #4 DESN) was completed in the 2023-2027 prior rate period and was placed in-service in Q1 2025. The capital expenditures included in this investment are for Stages 2 and 3, comprising the remaining two DESN stations and the transmission line. Stages 2 and 3 are also collectively referenced as the Energize Essex County Project as part of Hydro One's community and external engagement.

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[1] *Need for Bulk Transmission Reinforcement in the Windsor-Essex Region*, June 13, 2019, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Need-for-Bulk-Transmission-Reinforcement-in-Windsor-Essex-Region-June2019.pdf
Windsor-Essex Integrated Regional Resource Plan, April 3, 2025, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Windsor-Essex-2025-IRRP.pdf

[2] *Regional Infrastructure Plan Report Windsor-Essex*, October 20, 2025, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/RIP-Report-Windsor-Essex-Region-20-10-2025.pdf

Hydro One proposes to develop this project in three stages. Each stage will address station work to enable customer connections, as follows:

- **Stage 1 - Completed:** South Middle Road TS DESN#2 (formerly Leamington Area Station #4) was placed in-service in Q1 2025
  - Built a new 75/125 MVA, 230-27.6kV station with twelve feeders plus necessary switching and capacitive reactive facilities, at the South Middle Road TS site.
- **Stage 2:** Leamington Area Station #5 (target in-service for Q4 2032) and 230kV double circuit transmission line
  - Build a new 75/125 MVA, 230-27.6kV station with twelve feeders plus necessary switching and capacitive reactive facilities about 4 km north-east of Kingsville TS.
  - Build a new approximately 27 km 230kV double circuit transmission line into the Kingsville area to be tapped off the planned Lakeshore x Lauzon TS double-circuit 230kV line as recommended in the 2025 Windsor-Essex IRRP. The scope includes a restoration link connecting the new lines to the existing Leamington TS supply circuits, H38 and H39, to support load restoration requirements as defined by ORTAC. Stage 2 also includes the 230kV switching facilities required to enable the restoration connection.
- **Stage 3:** Leamington Area Station #6 (target in-service for Q4 2032)
  - Build a second new 75/125 MVA, 230-27.6kV DESN station with twelve feeders plus necessary switching and capacitive reactive facilities, approximately 6 km northeast of Leamington Area Station #5.

The new transmission line in Stage 2 is expected to be included in Hydro One's rate base and, as such, the associated capital expenditures have been included in the 2028-2032 forecast of this investment. The line was previously planned to be included in the rate base of a newly licensed affiliate transmission partnership and was therefore excluded from Hydro One's 2023-2027 forecast.

A map showing the project location is provided in Figure 1 below.

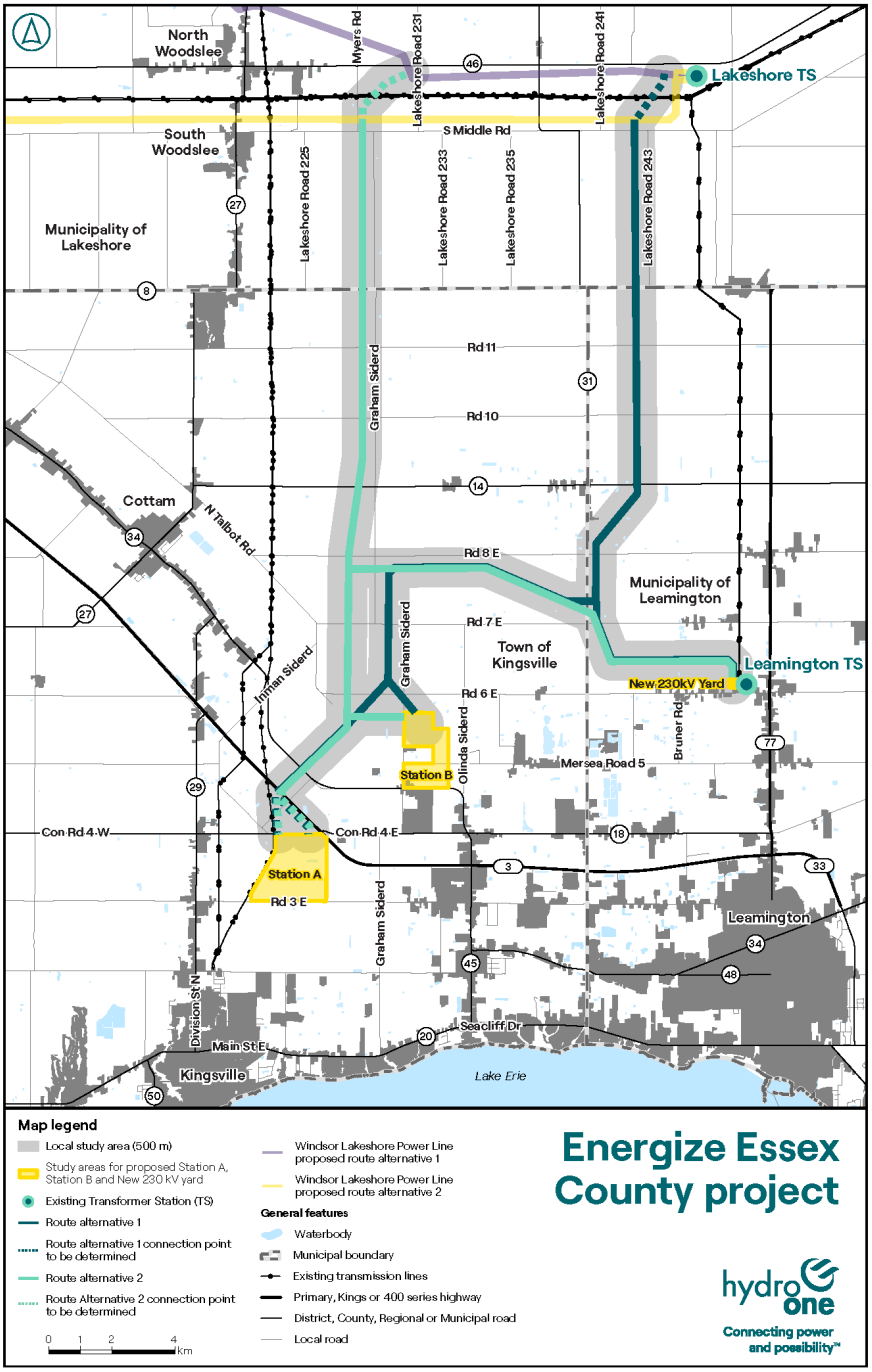

Figure 1: Map showing location of the new facilities

The System Impact Assessment and Customer Impact Assessment for Stages 2 and 3 were initiated in Q3 2021 but were put on pause at customer request. In Q3 2025, the SIA

was reactivated at customer request, which is expected to confirm that the project will not adversely affect the reliability of the IESO controlled grid.

Hydro One initiated the Class Environmental Assessment process, as required under the *Environmental Assessment Act*, *1990*, for the transmission line and both DESN stations in Q2 2026; approvals are expected to be obtained by Q3 2027.

3.0 OUTCOMES

This investment will provide the required increase in transformation capacity to supply load growth in the Kingsville-Leamington area.

3.1 OEB RRF OUTCOMES

Table 1 below presents the anticipated benefits as a result of the investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Satisfy customer requests for additional capacity.
Operational Effectiveness	• Enhance reliability of supply in the Kingsville - Leamington area. • Support network load restoration capabilities.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence to provide customers with non-discriminatory access.

4.0 EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in Table 2 below, will be fully recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customers.

The investment costs are forecast based on the best available information. Capital contribution amounts are estimated in accordance with Hydro One's Transmission Connection Procedures and the Transmission System Code. Project costs and capital contribution amounts are subject to true-up once the project is placed in-service, in accordance with the terms of the Connection Cost Recovery Agreement (CCRA).

Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One - Investment Expenditure

($M)	2028	2029	2030	2031	2032	Total
Gross Capital Expenditures	29.8	65.3	95.0	115.0	21.3	326.3
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	34.9	34.9
Net Capital Expenditures	**29.8**	**65.3**	**95.0**	**115.0**	**-13.7**	**291.3**

Table 3 below includes the forecasted project total and the prior project total as well as the maturity of the project at the time of filing, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

Table 3 - Hydro One – Rate Period Net Investment Expenditures

Investment Name	Prior Type	Prior Proj. Total[3]	Prior In-Service Year	Proj. Type	Proj. Total	In-Service Year
BUILD LEAMINGTON AREA TRANSFORMER STATIONS	P	154.7	2028	P	167.0	2032
BUILD LEAMINGTON AREA LINE	-	-	-	P	213.0	2032

As shown in Table 3, Hydro One expects the project total for the station components of this investment to be $12.3M higher than the prior project total for the corresponding scope of work, which comprises three transformer stations. The primary driver of the increase is the higher, sustained inflationary pressures experienced by Hydro One during the 2023-2027 prior rate period relative to the inflation assumptions embedded in its last transmission application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs Hydro One and other utilities have experienced during this period.

[3] "Prior Proj. Total" refers to the project total related to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

The scope of the stations work in Stages 2 and 3 is consistent with the prior investment plan. As noted above, Stage 1 is complete and Stages 2 and 3 are in the Planning and Definition stage. Prior to 2028, Hydro One will commence the environmental assessment and engineering design activities. Hydro One expects to incur $53.9M[4] prior to 2028 for the stations work, including the completion of Stage 1.

The line work was not included in this investment in the last transmission application (EB-2021-0110). Accordingly, the inclusion of the line work in this investment results in a forecast increase of $213.0M to the project total. Prior to 2028, Hydro One expects to continue Planning and Definition activities for the project, including environmental assessment and engineering design activities, and plans to incur $30.8M[5] during this period.

5.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

Hydro One is obligated to provide or expand facilities when requested by customers and as required to meet load growth in accordance with its Transmission Licence and the Transmission System Code. The status quo is not a feasible alternative as it does not provide adequate transformation capacity to supply customer load growth.

ALTERNATIVE 2: STAGED DEVELOPMENT OF NEW STATIONS AND LINE IN THE LEAMINGTON AREA (RECOMMENDED)

A staged development of the investment is recommended. Stage 1, the new station at the South Middle Road TS site situated near Lakeshore TS, has been completed and was placed in-service in Q1 2025. Stage 2 involves constructing a new station approximately 4 km north-east of the existing Kingsville TS as well as an approximately 27 km 230kV

[4] $48.9M is expected to be incurred during the 2023-2027 period and $5.0M was incurred prior to 2023.
[5] $29.3M is expected to be incurred during the 2023-2027 period and $1.5M was incurred prior to 2023.

double circuit transmission line, which includes a connection back to the Leamington TS supply circuits, H38 and H39, to support load restoration and associated 230kV switching facilities. Stage 3 will follow with a third station approximately 6 km northeast of the station constructed in Stage 2. The final station sites will be refined based on customer applications for connection and effective routing of distribution feeders. The transmission line location will be determined based on the environmental assessment and effective routing considerations and will be reflected in the Leave to Construct application. The need for these additional stations and the transmission line have been identified through the Regional Planning process for the Windsor-Essex region.

6.0 EXECUTION RISK AND MITIGATION

The execution risks for this investment include potential delays in securing the Section 92 and environmental assessment approvals for the transmission line. These risks will be mitigated by initiating the Section 92 application process and environmental assessment process in a timely manner. Typical project risks may also affect the timely completion of the project, such as the availability of system outages required to complete the work. As the stations will serve multiple customers, coordinated and timely approval of the multiple CCRAs will be required. These risks will be mitigated by working with the area customers to set a schedule that aligns with outage availability. There is also a risk that the area customers' requirements may change, resulting in a delay or cancellation of the need for this project. The CCRAs will allow Hydro One to recover the actual costs incurred even if the project is ultimately delayed or cancelled.

T-SA-11	**CUSTOMER CONNECTIONS – REGULATED ENTITIES**
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	-	114.7	157.9	311.8	98.3	13.9	696.6
HOSSM[1]	2.2	0.0	0.0	0.0	0.0	0.0	2.2

Summary:

Regulated customer connection projects are non-discretionary investments in response to local distribution company (LDC) needs. Regulated customer connection projects are non-discretionary because they are required to meet the forecasted load growth needs of LDCs, which cannot be serviced by existing Hydro One Transmission assets.

Hydro One is obligated to connect when requested by regulated customers in accordance with its Transmission Licence and the Transmission System Code (TSC). See ISD T-SA-12 for a discussion of non-regulated customer connection projects.

HOSSM is also obliged to connect when requested by regulated customers in accordance with its Transmission Licence and the TSC. One such investment, the Third Line TS PUC 230 kV connection, is detailed in Appendix C.

[1] See Appendix C for a description of HOSSM's Third Line TS PUC 230 kV Connection investment.

1.0 OVERVIEW

This investment includes 17 material regulated LDC customer connection projects for the 2028-2032 planning period. The projects are triggered by LDC customer connection requests, follow the same seven-phase connection process, and are subject to the same cost recovery framework under the TSC.

Hydro One is responding to an unprecedented increase in customer connections (see TSP Section 2.8). Hydro One is obligated to connect and serve growing electricity demand and prioritize non-discretionary System Access investments to meet these obligations. These investments involve constructing new or expanding existing transmission infrastructure, such as stations and lines, to meet LDC customer connection requests and provide the capacity required to serve forecasted load growth.

2.0 INVESTMENT NEED

Regulated customer connection projects are driven by LDC customers based on projected load growth. Projects are informed by direct customer requests and load forecasts as generally determined through ongoing regional planning processes, including Needs Assessments, Regional Infrastructure Plans and Integrated Regional Resource Plans completed in collaboration among Hydro One, LDCs and the Independent Electricity System Operator (IESO).

Regulated customer connection projects are non-discretionary because Hydro One is obligated to connect when requested by regulated LDC customers in accordance with its Transmission Licence and the TSC.

3.0 INVESTMENT DESCRIPTION

Proposed regulated customer connection project scopes are determined with consideration of the forecasted load growth, regional planning recommendations, customer in-service requirements, current system limitations, technical requirements and cost efficiency. Scope generally includes building new or expanding existing transmission infrastructure, such as stations and lines, to meet capacity requirements. The individual Hydro One projects under this investment are listed in Appendix A with details of their scope, need and alternatives considered.

Regulated customer connection projects follow Hydro One's seven phase process for new and modified connections to its transmission system. Each of the seven phases consists of multiple steps.

The primary entities involved in the connection process are the regulated customer/LDC, Hydro One, the IESO, the Ontario Energy Board (OEB) and the Electrical Safety Authority. There is a material level of effort from Hydro One and the regulated customer beginning in Phase 0 which increases as the project matures through commissioning. Completion of all seven phases can span from approximately three to five years, depending on scope and complexity of the connection. The main activities during each of the seven phases are as follows:

1. **Phase 0 Feasibility Study (optional) (5-10 months):** Hydro One and the regulated customer perform a preliminary assessment of the proposed connection and, if deemed necessary, an in-depth assessment known as a Feasibility Study is completed to identify the preferred options and preliminary project cost estimates based on available information. This optional phase is generally targeted at more complex connections.

2. **Phase 1 Connection Application (1-2 months):** Hydro One completes a preliminary assessment of the regulated customer request focused on general technical requirements, budget and available connection facilities. The customer completes the Connection Assessment Approval application and submits it to Hydro One and the IESO.

3. **Phase 2 Customer Impact Assessment (12+ months):** The IESO completes a System Impact Assessment to confirm the project will not adversely affect the reliability of the IESO-controlled grid and Hydro One completes a Customer Impact Assessment to confirm that the project will not adversely affect service to other transmission connected customers.

4. **Phase 3 Connection Cost Estimate (8+ months):** The customer and Hydro One align on the scope of work, determine construction responsibilities and any financial

contributions from the connecting customer for the required facilities and establish project cost estimates based on available information.

5. **Phase 4 Connection Approval and Connection Cost Recovery Agreement (CCRA) (1+ month):** Hydro One and the customer execute the CCRA which sets out estimated project costs and the portion of final project costs to be incurred by the customer based on the economic evaluation procedures detailed in Hydro One's OEB approved Transmission Connection Procedures. Execution of the CCRA initiates Hydro One's process to release funds to proceed with detailed engineering, order equipment, and acquire the necessary regulatory approvals, permits, and licences leading to the construction of the agreed scope of work.[2]

6. **Phase 5 Design and Build (12-24 months):** The facilities are designed and construction is executed. Regulated customer connection projects are generally complex and can span multiple years. Execution therefore follows the scalable transmission Capital Project Delivery Model discussed in TSP Section 2.11 to drive safe and efficient outcomes in the context of the delivery of a large and complex transmission investment portfolio.

7. **Phase 6 Commissioning (1-2 months):** The connection facility is inspected and tested and placed in service. The CCRA is updated with the final actual costs and the customer is invoiced.

Hydro One's connection process establishes a transparent, consistent and predictable path to complete regulated customer connection projects.

[2] Depending on scope, a project may be subject to completion of an Environmental Assessment in accordance with the *Environmental Assessment Act*, Leave to Construct approval from the OEB under Section 92 of the *Ontario Energy Board Act*, or real estate and property agreements.

4.0 OUTCOMES

4.1 OEB RRF OUTCOMES

Table 1 below presents the anticipated benefits from the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 1 - Outcome Summary

Customer Focus	• Maintain reliable power delivery at the regional level • Satisfy customer request for additional capacity.
Operational Effectiveness	• Increase capacity in the area.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence to provide customers with non-discriminatory access.

5.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's forecast capital expenditures under this investment for the 2028-2032 planning period. See Appendix B for a summary of the investment expenditures by regulated customer connection project. The annual expenditure profile reflects the forecast development and construction schedules of the underlying customer connection projects. The level and timing of forecast capital contributions similarly reflect the applicable cost recovery arrangements and anticipated project schedules.

Project costs are recoverable through incremental revenue from the appropriate rate pool and customer capital contributions under the CCRA. Customer capital contributions under the CCRA may not be required when project costs are fully recovered through incremental revenue. The investment costs are forecast based on best available information. Capital contribution amounts are estimated pursuant to Hydro One's Transmission Connection Procedure in accordance with the TSC. Project costs and capital contribution amounts are subject to true-up once the project is placed in-service, subject to the terms of a CCRA. CCRAs allow Hydro One to recover the actual costs incurred even if a customer elects to cancel a project.

Table 2 - Hydro One – Investment Expenditures[3,4]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	152.2	197.6	381.9	520.0	286.7	1,538.4
Less Removals	1.6	0.1	0.0	0.0	0.0	1.7
Less Capital Contributions	35.9	39.7	70.1	421.7	272.8	840.1
Net Capital Expenditures	**114.7**	**157.9**	**311.8**	**98.3**	**13.9**	**696.6**

6.0 ALTERNATIVES

Appendix A provides a discussion of alternatives for each regulated customer connection project under this investment.

7.0 EXECUTION RISK AND MITIGATION

Under the Transmission Capital Project Delivery Model described in TSP Section 2.11, project risks are identified and mitigation plans are implemented. Risks that can impact the completion of regulated customer connection projects include the following:

- Outage Constraints: Planned outages are required to replace and construct assets. Outages may impact individual assets, sections of a station or a transmission line, or an entire station. Outage risk is minimized by ongoing collaborative planning and advanced coordination among stakeholders, such as the IESO and transmission customers, to minimize customer impact and the requirement for work reprioritization.
- Resource Constraints due to Increased Work Volumes: Hydro One plans resources for its known and forecasted volume of projects, including regulated customer connection projects. Volumes of work above forecast cause resourcing risk because all transmission station projects use the same teams of management and engineering resources and projects in the same geographical location use the same teams of construction and commissioning resources. Resourcing risk is mitigated by the availability of flexible casual resources and contracted resources which can commence work on short notice and relieve peak periods.

[3] Figures presented in the tables may not sum to the totals shown due to rounding.
[4] Forecast net capital expenditures for the 2028-2032 period include $6.9M of immaterial projects.

- Construction Execution Challenges: Existing station equipment may require retrofits to accommodate new assets because station design and equipment standards have evolved. Significant design and construction is required if modification cannot be completed in the same physical location due to space constraints, outages or safety considerations. This risk is mitigated by early identification of project constraints during phases one to three of the connection process to identify alternatives.
- Real Estate Requirements: Station or transmission line right-of-way expansion and new land may be required when assets cannot be replaced in the same physical location. This risk is mitigated by early identification of project constraints during phases one to three of the connection process to identify alternatives.
- Procurement challenges: Major equipment procurement lead times can be long. Hydro One engages vendors at appropriate times in the planning process to ensure sufficient lead times to secure major equipment. See Exhibit C-06-01, Section 3.0 for a description of Hydro One's approach to inventory planning, procurement, and management of critical and long-lead items.

APPENDIX A – DESCRIPTION OF FORECAST INVESTMENTS

This Appendix describes the need for each investment, its scope, the alternatives considered, and applicable regional planning reports and directives.

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
T-SA-11.01	Markham TS #5 - Build new DESN	Construction of a new 230/27.6 kV Dual Element Spot Network (DESN) station with two 75/125MVA transformers along with a new 27.6 kV switchyard at the existing Buttonville TS site; the DESN station will be supplied by the existing 230 kV transmission circuits (P45/P46), which also supply the existing Buttonville TS; the investment will increase the existing capacity at Buttonville TS by approximately 170MVA; the investment is required to meet Alectra's forecasted customer load growth in the City of Markham. Prior to 2028, Hydro One expects to complete the planning phase and begin execution of the project.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's Transmission Licence (TL) nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center 3. Build New DESN Station and Switchyard (recommended) Only practical alternative to provide needed capacity; aligns with GTA North York IRRP recommendations	GTA North York Region Integrated Regional Resource Plan (IRRP) October 2025

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
T-SA-11.02	InnPower MTS - 230 kV E28/29B Line Connection	Construct a new 230 kV double circuit transmission line along an existing right of way tapping to the 230 kV E28B/E29B circuits (Essa TS x Barrie TS); the investment is required to connect the planned InnPower constructed and owned 230/27.6 kV 50/83MVA transformer station; the investment is required to meet InnPower forecasted load growth in the City of Barrie. Prior to 2028, Hydro One plans to commence archeology studies, and sign a CCRA with InnPower for the required work.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Connect to Existing Low Voltage Feeder as Embedded Customer (rejected) Involves building a distribution tap to the closest Alectra owned feeder to utilize any spare capacity; closest feeder operated by Alectra does not have spare capacity. 3. Connect to New 44 kV feeder from Barrie TS (rejected) Constructing new 44 kV feeder position at Barrie TS dedicated solely for InnPower load would not provide sufficient supply capacity to meet InnPower's demand forecast; there are also physical space limitations inside Barrie TS. 4. Utilize existing 44 kV Feeders (rejected) Loading existing feeders beyond typical planning guidelines would not provide sufficient supply capacity	South Georgian Bay-Muskoka Needs Assessment (NA) August 2025; South Georgian Bay-Muskoka Scoping Assessment December 2025

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
			needed to meet InnPower's demand forecast 5. Construct a new 230 kV double circuit transmission line along an existing right of way tapping to the 230 kV E28B/E29B circuits and connect the customer transformer station. (recommended) This alternative is preferred as it is the only alternative that provides the required supply capacity for the customer. This recommendation also aligns with the South Georgian Bay Muskoka Regional Infrastructure Planning studies and reports.	
T-SA-11.03	Connect North Whitby MTS	Construction of a 230 kV tap from circuit P15C, a new single-circuit tap from circuit T28C that is approximately 4.5 km on a new right-of-way to enable sectionalization and operational flexibility; scope supports Elexicon Energy's proposed construction of a new 230/44 kV MTS with up to 160 MW of load capability; the investment is	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center	GTA East NA December 2024

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
		required to meet Elexicon Energy's forecasted load growth in the Town of Whitby. Prior to 2028, Hydro One expects to complete the Feasibility Study and execute a CCRA with the customer.	3. Construct New 230/44 kV MTS (recommended) Only practical alternative to provide required supply; additional benefit of alleviating capacity concerns on 230 kV subsystem in the area; aligned with recommendations in the GTA East RIP	
T-SA-11.04	Enfield TS #2	Construction of a new 230/44 kV DESN station with two 75/125MVA transformers along with a new 44 kV switchyard in the Oshawa-Clarington sub-region; will bring approximately 160MVA of extra capacity; the investment is required to meet the forecasted customer load growth in the Oshawa-Clarington sub-region and associated demands on Hydro One Distribution, Oshawa PUC and Elexicon Inc - existing stations in the Oshawa-Clarington sub-region, such as Wilson TS and Thornton TS, will be loaded beyond normal station supply capacity in the near term.	1. Status Quo (rejected) Would not meet customer load growth needs nor future load growth; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center 3. Construct New 230 kV/44 kV DESN Station (recommended) The new DESN station would meet load demand by providing extra station capacity that the area currently lacks; new step-down station will be built near	GTA East NA December 2024

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
			the customer load and connection circuits will be built to connect to serve the new load growth	
T-SA-11.05	Napanee TS: Build new DESN2	Construction of a second DESN station at Napanee TS to be supplied from the existing 230 kV X21/X22 circuits; will provide additional transformation capacity to serve forecasted load growth in the Greater Napanee area; the investment is required to meet forecasted area load growth by Hydro One Distribution associated with projected large customer connection(s); station's non coincident peak net load is expected to exceed both its summer and winter Long Term Ratings.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Replace existing transformers at Napanee TS with 125MVA units and complete associated station upgrades (rejected) Challenges with expansion of legacy station including structure type and other series equipment ampacity (breakers, switches, etc.) along with outages to facilitate replacement of transformers within existing switchyard. 3. Build New DESN2 at Napanee TS (recommended) Provides sufficient capacity and operational flexibility to meet forecast load growth and is scalable as customer demand materializes	Peterborough to Kingston NA December 2024

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
T-SA-11.06	New GTA West Alectra MTS connection	Construction of two 230 kV underground cable connections of approximately 1.6 km from Hydro One's 230 kV circuits V41H/V42H to Alectra owned MTS; scope includes protection and control systems; length of the cable is approximately 2 km; new Alectra-owned station will supply up to 150MW new loads according to Alectra's forecast; the investment is required to meet Alectra forecasted customer load growth in the Mississauga and Brampton regions.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Build 230 kV Lines to Supply New Station (recommended) Most practical alternative to provide the needed supply; aligns with recommended plan in the GTA West Regional Needs Assessment	GTA West NA August 2024
T-SA-11.07	Build New 230 kV CKT Merivale TS X Greenbank MTS	Construction of a new 4 km 230 kV transmission circuit between Merivale TS and the new Greenbank MTS in west Ottawa; new circuit will provide a second 230 kV supply to Greenbank MTS; project must be coordinated with planned upgrades at Merivale TS; as an interim configuration, Greenbank MTS will initially be supplied by the existing 230 kV circuit E34M until the new circuit is placed in service; the investment is	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. New Station Supplied by a Single 230 kV Circuit E34M (rejected) Would initially support load growth but would limit the long-term growth capability and create voltage and reliability challenges as documented in the 3rd Cycle Greater Ottawa IRRP/RIP; would also require	3rd Cycle Greater Ottawa IRRP and RIP February 2026

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
		required to meet Hydro Ottawa's expected load growth in the City of Ottawa. Prior to 2028, Hydro One expects to complete the planning phase and begin execution of the project.	the circuit to be connected to Merivale TS to maintain acceptable voltages. 3. New Station Supplied by Two 230 kV Circuits (recommended) Provides sufficient capacity and reliability to meet forecast load growth over the planning horizon and across a wider range of operating conditions; aligns with recommendations under the IRRP process and reaffirmed in the Greater Ottawa RIP	
T-SA-11.08	Dundas TS: Additional 230 kV Transformation	Construction of two new 230/27.6 kV DESN stations each with two 75/125MVA transformers, using one existing 27.6 kV switchyard at the existing Dundas TS site; includes conversion of the existing Dundas TS and Dundas TS #2 from 115 kV to 230 kV; all the loads at existing Dundas TS and Dundas TS #2 115 kV/ 27.6 kV DESNs will be moved to the two new 230 kV DESNs; will free up the existing 115 kV system's supply capacity by approximately 188MW; the investment is	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center 3. Build Two New 230 kV DESNs at Dundas TS (recommended) Only practical alternative that provides required additional supply needs in the area with	3rd Cycle Burlington to Nanticoke IRRP and RIP November 2024

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
		required to meet Alectra's forecasted load growth in the City of Hamilton.	the additional benefit of alleviating capacity concerns on 115 kV subsystem; aligns with recommendations under the 3rd Cycle Burlington to Nanticoke IRRP and IRP	
T-SA-11.09	Brant TS: New 230 DESN	Construct approximately 12 km of 230 kV double circuit line tapping M20D/ M21D circuits between Middleport TS and Detweiler TS to a location close to Brant TS and Powerline MTS; construct two 230/27.6 kV DESN stations using 75/125MVA transformers; all the Brant TS and Powerline MTS loads will be transferred to the new 230/ 27.6 kV DESNs; the investment is required to meet forecasted load growth and future transformation capacity needs in Brant County by Grandbridge Energy.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center 3. Build Two 230 kV DESNs Near Brant TS (recommended) Only practical alternative to provide additional supply capacity in the Brant area; includes providing additional supply and transformation capacity in the area; aligns with recommendations in the 3rd Cycle Burlington to Nanticoke IRRP and RIP	3rd Cycle Burlington to Nanticoke IRRP and RIP November 2024

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
T-SA-11.10	Middleport TS: New 230 DESN	Construction of a new 230/27.6 kV DESN station with two 75/125MVA transformers close to Hydro One's existing Middleport TS; new DESN station will be supplied by the existing 500/ 230 kV Middleport TS ; the investment will provide new additional supply capacity of approximately 170MVA in the Middleport TS area; the investment is required to provide new additional transformation capacity to accommodate load growth forecasted by Hydro One Distribution in the area around Hydro One's existing 500 kV Middleport TS. Prior to 2028, Hydro One expects to complete project definition and estimating for this project.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center 3. Construct a new DESN Station Near Middleport TS (recommended) Only practical alternative to provide the required supply capacity; Hydro One property footprint of Middleport TS has sufficient space to build the new facilities, and there is sufficient capacity available to supply the new transformer station; is aligned with the recommended plan in the 3rd Cycle Burlington to Nanticoke RIP	3rd Cycle Burlington to Nanticoke RIP November 2024
T-SA-11.11	Build New Tillsonburg Area DESN	Construction of a new 230/27.6 kV DESN station with two 75/125MVA transformers along with a new 27.6 kV switchyard in the Town of Tillsonburg;	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC	N/A

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
		construction of a new, approximately 14 km, 230 kV transmission line tap; the investment will bring approximately 170MVA of extra capacity to serve the load growth of the industrial area; the investment is required to increase transformation capacity to accommodate customer load growth in the Town of Tillsonburg forecasted by Hydro One Distribution Prior to 2028, Hydro One began preliminary engineering.	2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center 3. Construct New DESN Station and Switchyard (recommended) Only practical alternative to provide the required supply capacity; new DESN station will be connected to nearest Hydro One transmission lines; new step-down stations will be built at the customer location and connection circuits will be built to connect the new station	
T-SA-11.12	Build New Yarmouth Centre DESN	Construction of a new 230/27.6 kV DESN station with two 75/125MVA transformers along with a new 27.6 kV switchyard at the proposed Yarmouth Yards industrial area; construction of a new, approximately 17 km, 230 kV transmission line tap; the investment will bring approximately 170MVA of extra capacity to serve the load growth of the industrial area; the	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center	N/A

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
		investment is required to increase transformation capacity to accommodate forecasted customer load growth in the City of St. Thomas by Hydro One Distribution Prior to 2028, Hydro One has begun preliminary engineering.	3. Construct New DESN Station and Switchyard (recommended) Only practical alternative to provide the required supply capacity; new DESN station will be connected to nearest Hydro One transmission lines; new step-down stations will be built at the customer location and connection circuits will be built to connect the new station	
T-SA-11.13	New 230 kV Crowland TS	Construction of a new 230/27.6 kV DESN station with two 75/125MVA transformers along with a new 27.6 kV switchyard at the existing Crowland TS site; new DESN station will be supplied by new 230 kV line taps from transmission circuits (Q24HM/Q29HM); the investment will increase the existing capacity at Crowland TS by approximately 70MW; the investment is required to facilitate load growth forecasted in the Welland area by Wellland Hydro and Hydro One Distribution; System Impact Assessment and Customer	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Rebuild Existing DESN and Add 2nd DESN (rejected) Would require the existing Crowland TS transformers to be replaced, and the station to be refurbished; an additional DESN would need to be built to handle the increased load; alternative does not alleviate the constrained supply on the 115 kV sub-system, in particular it exceeds the supply limit of the Allanburg	Niagara IRRP December 2022 and 2nd Cycle Niagara Region RIP July 2023

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
		Impact Assessment were completed in Q4 2025. Hydro One's Leave to Construct application under Section 92 of the OEB Act was approved by the OEB in Q3 2026. Prior to 2028, Hydro One expects to begin the site preparation and procurement of power transformers.	autotransformers and 115 kV A6C/A7C circuits. 3. Construct New 230 kV DESN Station (recommended) Existing footprint of Crowland TS has sufficient space to build the new facilities, and there is sufficient capacity on the existing 230 kV Q24HM/Q29HM lines to supply the new transformer station; only practical alternative to provide the capacity needed; aligned with recommendations in the Niagara IRRP and Niagara Region RIP	
T-SA-11.14	Nebo TS: New DESN	Construction of a new 230/27.6 kV DESN station with two 75/125MVA transformers along with a new 27.6 kV switchyard in the City of Hamilton; the investment will bring approximately 170MVA of extra capacity to serve the load growth of the area; the investment is required to meet Alectra's forecasted customer load growth in the City of Hamilton.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity or present material challenges related to distance from load center 3. Construct New DESN Station and Switchyard (recommended)	3rd Cycle Burlington to Nanticoke RIP November 2024

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
			A new 230/27.6 kV DESN at Nebo TS is the optimal approach to addressing the additional transformation requirements as per Regional Planning forecasts	
T-SA-11.15	New Coatsworth DESN 1 and 2 and Tap Connection	Construction of approximately10 km of new 230 kV double circuit line tapping C43H/C65H circuits between Lakeshore TS and Chatham SS to a location close in Coatsworth area and building two 230/27.6 kV DESN stations to supply new load of approximately 380MW; the investment is required to meet projected load growth in the Coatsworth Region forecasted by Hydro One Distribution.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Supply New Load with Lemington TS (rejected) Closest transformer station to Coatsworth area is Leamington TS; station does not have enough capacity to supply the additional load 3. Construct 230 kV Line Taps and Two New DESN Stations in Coatsworth Area (recommended) Only practical way to provide the necessary additional supply capacity in the Coatsworth area; aligned with results of Windsor-Essex RIP	3rd Cycle Windsor-Essex RIP October 2025

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
T-SA-11.16	King Edward Metal Clad Upgrade	Replace and upgrade 13.2 kV cables of transformers T3 and T4 (four sets total); replace 13.2 kV metal clad breakers (transformers and bus ties, total of six breakers); complete associated protection and control work; investment will result in approximately 30MW of additional capacity at the Kind Edward station to meet the projected load growth in the Ottawa Region forecasted by Hydro Ottawa Ltd.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either have no capacity in the long term or present material challenges related to distance from load center 3. Replace 13.2 kV cable (recommended) Only practical long-term alternative to provide the required supply capacity	Ottawa Area (IRRP) July 2025; Greater Ottawa Area RIP February 2026
T-SA-11.17	Northern York TS #2	Construction of a new 230/44 kV DESN station with two 75/125MVA transformers along with a new 44 kV switchyard in the vicinity of town of Newmarket.	1. Status Quo (rejected) Would not meet customer load growth needs; not aligned with Hydro One's TL nor the TSC 2. Transfer Loads to Other Area Stations (rejected) Other stations either not expected to have capacity or present material challenges related to distance from load center 3. Construct New DESN Station and Switchyard (recommended)	GTA North RIP May 2026; GTA North IRRP October 2025

ISD Ref.	Investment Name	Scope Summary and Need	Alternatives	Applicable Regional Planning Reports and Directives
			A new 230/44 kV DESN is the optimal approach to address the additional transformation requirements as per Regional Planning forecasts	

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in the table below in reference to project total variances and overall project schedule variances.

1

Table B1 - Hydro One - Detailed Material Investment Costs ($M)

ISD Ref.	Investment Name		Net Capital Investment							Project Forecast			Prior Project Forecast[5]			
			Act/Fcst 23-27[6]	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
T-SA-11.01	Markham TS #5 - Build new DESN	Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	P	62.2	2029	-	P	2.7	-
		Net Capital Expenditure	25.8	27.1	9.3	0.0	0.0	0.0	36.5							
		Since the Plan was prepared, the scope of this project changed from connecting a customer's MTS to building a new DESN for the customer.														
T-SA-11.02	Innpower MTS - 230 kV E28/29B Line Connection	Capital Contributions	-41.8	0.0	0.0	0.0	0.0	0.0	0.0	E	44.8	2028	-	-	-	-
		Net Capital Expenditure	-3.7	48.5	0.0	0.0	0.0	0.0	48.5							
T-SA-11.03	Connect North Whitby MTS	Capital Contributions	-1.5	-4.1	-12.7	-5.5	0.0	0.0	-22.3	P	4.4	2031	-	-	-	-
		Net Capital Expenditure	0.0	0.0	0.0	4.4	0.0	0.0	4.4							
T-SA-11.04	Enfield TS #2	Capital Contributions	0.0	0.0	0.0	0.0	0.0	-56.3	-56.3	P	45.2	2032	-	-	-	-

[5] "Prior Project Forecast" refers to the forecast project total and in-service date when Hydro One revised the capital and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[6] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

ISD Ref.	Investment Name		Net Capital Investment							Project Forecast			Prior Project Forecast[5]			
			Act/Fcst 23-27[6]	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
		Net Capital Expenditure	0.0	1.9	2.9	14.9	45.6	-20.1	45.2							
T-SA-11.05	Napanee TS: Build new DESN2	Capital Contributions	0.0	-1.3	-2.0	0.0	0.0	-50.4	-53.8	P	16.2	2032	-	-	-	-
		Net Capital Expenditure	0.0	0.0	0.0	10.3	31.4	-25.5	16.2							
T-SA-11.06	New GTA West Alectra MTS connection	Capital Contributions	0.0	-0.8	-0.9	-8.6	-44.1	-41.4	-95.7	P	19.3	2032	-	-	-	-
		Net Capital Expenditure	0.0	0.0	0.0	2.4	12.2	4.6	19.3							
T-SA-11.07	Build New 230 kV CKT Merivale TS X Greenbank MTS	Capital Contributions	-3.3	-5.8	-9.2	-5.5	0.0	0.0	-20.6	P	17.4	2030	-	-	-	-
		Net Capital Expenditure	0.0	4.5	7.7	5.2	0.0	0.0	17.4							
T-SA-11.08	Dundas TS: Additional 230	Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	P	107.4	2032	-	-	-	-

ISD Ref.	Investment Name		Net Capital Investment							Project Forecast			Prior Project Forecast[5]			
			Act/Fcst 23-27[6]	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
	kV Transformation	Net Capital Expenditure	0.0	0.4	0.5	10.4	58.2	37.8	107.4							
T-SA-11.09	Brant TS: New 230 DESN	Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	P	67.9	2032	-	-	-	-
		Net Capital Expenditure	0.0	0.5	0.5	6.5	36.6	23.7	67.9							
T-SA-11.10	Middleport TS: New 230 DESN	Capital Contributions	-7.1	0.0	0.0	-29.7	0.0	0.0	-29.7	P	34.7	2030	-	-	-	-
		Net Capital Expenditure	-0.6	6.8	32.5	-4.0	0.0	0.0	35.2							
T-SA-11.11	Build New Tillsonburg Area DESN	Capital Contributions	0.0	0.0	0.0	0.0	-175.1	0.0	-175.1	P	24.1	2031	-	-	-	-
		Net Capital Expenditure	0.5	0.5	29.7	90.0	-96.7	0.0	23.5							
T-SA-11.12		Capital Contributions	0.0	0.0	0.0	0.0	-179.7	0.0	-179.7	P	34.3	2031	-	-	-	-

ISD Ref.	Investment Name		Net Capital Investment							Project Forecast			Prior Project Forecast[5]			
			Act/Fcst 23-27[6]	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
	Build New Yarmouth Centre DESN	Net Capital Expenditure	0.5	0.5	44.6	90.0	-101.3	0.0	33.8							
T-SA-11.13	New 230 kV Crowland TS	Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	E	76.5	2029	-	-	-	-
		Net Capital Expenditure	63.3	7.5	5.7	0.0	0.0	0.0	13.2							
T-SA-11.14	Nebo TS: New DESN	Capital Contributions	0.0	0.0	0.0	0.0	0.0	-38.8	-38.8	P	36.2	2032	-	-	-	-
		Net Capital Expenditure	0.0	0.6	6.9	7.1	33.8	-12.1	36.2							
T-SA-11.15	New Coatsworth DESN 1 and 2 and Tap Connection	Capital Contributions	0.0	0.0	0.0	0.0	0.0	-34.1	-34.1	P	168.6	2032	-	-	-	-
		Net Capital Expenditure	0.0	1.1	8.4	62.6	69.6	26.9	168.6							
T-SA-11.16	King Edward M/C Upgrade	Capital Contributions	0.0	0.0	-0.5	-0.5	-2.0	-4.0	-7.0	P	9.0	2033	-	-	-	-
		Net Capital Expenditure	0.0	0.0	0.0	0.5	2.5	4.0	7.0							
T-SA-11.17	Northern York TS#2	Capital Contribution	0.0	0.0	0.0	0.0	0.0	0.0	0.0	P	29.0	2035	-	-	-	-

ISD Ref.	Investment Name		Net Capital Investment							Project Forecast			Prior Project Forecast[5]			
			Act/Fcst 23-27[6]	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
		Net Capital Expenditure	0.0	0.0	0.2	0.5	0.9	7.9	9.5							

APPENDIX C – HOSSM THIRD LINE TS PUC 230 kV CONNECTION INVESTMENT

This investment is required to connect a new 230 kV double circuit transmission line originating from a new customer transformer station, Tagona West CTS, at Hydro One Sault Ste. Marie's (HOSSM) Third Line Transformer Station (TS). The new station and double circuit line will be built, owned and operated by an unaffiliated licenced transmitter, PUC (Transmission) LP (PUC). The connection investment at Third Line TS will enable HOSSM to serve PUC's neighbouring transmission system, which will supply the local steel manufacturer's new Electric Arc Furnaces (EAF).

As described in TSP 2.10, Hydro One has been operationally integrated with HOSSM since October 1, 2018. However, HOSSM remains financially and legally separate until a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One.

HOSSM continues to be the licensed owner and operator of its transmission system, however, it relies on Hydro One to carry out the day-to-day operations, pursuant to affiliate service agreements as outlined in Exhibit D-02-03. Although HOSSM is distinct and its approved revenue requirement is established separately, many processes including the asset management, planning and work execution approaches are common and integrated with Hydro One Transmission and are described within Hydro One’s SPF and TSP.

Since HOSSM’s programs are operationally integrated with Hydro One, the investment need, investment description and outcomes, as described above for Hydro One in Sections 2.0, 3.0, and 4.0, respectively, are applicable to HOSSM’s Third Line TS PUC 230 kV Connection investment.

PUC Transmission and HOSSM were joint applicants in the Section 92 application filed with the OEB for approval to construct the new 230 kV double circuit line, new Tagona West CTS, and the connection work at Third Line TS. The Section 92 application received approval to construct in the Decision and Order issued in August 2024.

Table C-1 below summarizes HOSSM's forecast net capital expenditures for the 2027-2032 rate period.

Table C-1 - HOSSM – Investment Expenditures

($M)	2027	2028	2029	2030	2031	2032	Total 27-32
Gross Capital Expenditures	2.2	0.0	0.0	0.0	0.0	0.0	2.2
Less Removals	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
Net Capital Expenditures	**2.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**2.2**

At the time of filing this Application, the project maturity is Execution (E), which reflects fully approved project work.

This investment is expected to be placed in-service in 2027 at a forecast project total of $67.1M. Prior to 2027, HOSSM commenced execution and undertook the majority of the project scope and expects to incur $64.9M during this period.

HOSSM considered the following alternatives before selecting the preferred investment.

ALTERNATIVE 1: STATUS QUO

This alternative would require the local steel manufacturer to continue to connect its new EAFs to the existing 115 kV connection point. However, the capacity at the existing 115 kV connections cannot fully support the increased load and would require the EAFs to restrict their operations. This alternative would not meet the customer's needs or address the customer's request.

ALTERNATIVE 2: CONNECT TO HOSSM'S 230 KV SYSTEM (RECOMMENDED)

This alternative requires expansion of the 230 kV yard at HOSSM's Third Line TS to accommodate two new 230 kV circuits that will supply the local steel manufacturer's new EAF load via PUC's new Tagona West TS. This new connection point will allow the EAFs

to operate at full capacity once bulk system reinforcement projects are completed by the end of the decade.

The project is in advanced stages of execution and as such has mitigated major risks impacting capital expenditure. All required regulatory approvals have been received, and procurement of long lead time materials is completed.

There is the potential for normal project risk that affects timely completion of the project, such as the availability of outages, and completion of PUC's construction work to connect to HOSSM's station, as well as those risks outlined above in Section 7.0. These risks will be mitigated by working with PUC and setting a schedule that aligns with outage availability.

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T-SA-12	**CUSTOMER CONNECTIONS – NON-REGULATED ENTITIES**
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($ Millions)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	65.1	55.5	42.4	1.0	0.0	163.9

Summary:

Non-regulated customer connection projects are non-discretionary investments executed in response to the needs of large commercial or industrial customers requesting to connect directly to Hydro One's transmission system. Non-regulated customer connection projects are non-discretionary because they are required to meet forecasted customer load growth needs that cannot be serviced by existing Hydro One Transmission assets. Hydro One is obligated to expand facilities when requested by non-regulated customers in accordance with its Transmission Licence and the Transmission System Code. See ISD T-SA-11 for a discussion of regulated customer connection projects.

1.0 OVERVIEW

This investment includes Hydro One's non-regulated customer connection projects for the 2028-2032 planning period. This ISD consolidates all such projects under one investment because they are all triggered by industrial customer connection requests, follow the same seven-phase connection process, and are subject to the same cost recovery framework under the Transmission System Code (TSC).[1]

Hydro One is facing an unprecedented increase in customer connections (see TSP Section 2.8). Hydro One is obligated to connect and serve growing electricity demand and prioritize non-discretionary System Access investments to meet these obligations. Investments in load customer connection work are required to build new or expand existing transmission infrastructure, such as stations and lines, to meet explicit customer connection requests from large industrial loads.

2.0 INVESTMENT NEED

Non-regulated customer connection projects are requested by customers based on projected load growth and a need to be directly connected to Hydro One's transmission system due to the magnitude of load or connection requirements. For example, the expansion of a large industrial customer's facility or connection of a data centre. Customer requests are informed by load forecasts and are assessed by Hydro One upon receipt of a customer connection application.

Non-regulated customer connection projects are non-discretionary because Hydro One is obligated to expand facilities when requested by non-regulated customers in accordance with its Transmission Licence and the TSC.

[1] Hydro One, Hydro One Transmission Connection Procedures, Nov 2015, Page 3, Figure 1: https://www.hydroone.com/businessservices_/Documents/Transmission%20Connection%20Procedures_Updated%20-%20Nov%2018%202015.pdf

3.0 INVESTMENT DESCRIPTION

Proposed non-regulated customer connection project scopes are determined with consideration for the forecasted load growth, customer in-service requirements, current transmission system limitations, technical requirements and cost efficiency. The scope, need and alternatives considered for the individual projects under this investment are listed in Appendix A.

Non-regulated customer connection projects follow Hydro One's seven phase process for new and modified connections to its transmission system. Each of the seven phases consists of multiple steps.

The primary entities involved in the connection process are the non-regulated customer, Hydro One, the IESO, the OEB and the Electrical Safety Authority. There is a material level of effort from Hydro One and the non-regulated customer beginning in Phase 0 which increases as the project matures through commissioning. Completion of all seven phases can span from approximately three to five years, depending on scope and complexity of the connection. The main activities during each of the seven phases are as follows:

1. **Phase 0 Feasibility Study (optional) (5-10 months):** Hydro One and the non-regulated customer perform a preliminary assessment of the proposed connection and, if deemed necessary, an in-depth assessment known as a Feasibility Study is completed to identify the preferred options and preliminary project cost estimates based on available information; this optional phase is generally targeted at more complex connections.

2. **Phase 1 Connection Application (1-2 months):** Hydro One completes a preliminary assessment of the non-regulated customer request focused on general technical requirements, budget and available connection facilities. The customer completes the Connection Assessment Approval application and submits it to Hydro One and the IESO.

3. **Phase 2 Customer Impact Assessment (12+ months):** The IESO completes a System Impact Assessment to confirm the project will not adversely affect the reliability

of the IESO-controlled grid and Hydro One completes a Customer Impact Assessment to confirm that the project will not adversely affect service to other transmission connected customers.

4. **Phase 3 Connection Cost Estimate (8+ months):** The customer and Hydro One align on the scope of work, determine construction responsibilities and any financial contributions from the connecting customer for the required facilities and establish project cost estimates based on available information.

5. **Phase 4 Connection Approval and Connection Cost Recovery Agreement (CCRA) (1+ month):** Hydro One and the customer execute the CCRA which sets out estimated project costs and the portion of final project costs to be incurred by the customer based on the economic evaluation procedures detailed in Hydro One's OEB-approved Transmission Connection Procedures. Execution of the CCRA initiates Hydro One's process to release funds to proceed with detailed engineering, order equipment, and acquire the necessary regulatory approvals, permits, and licences leading to the construction of the agreed scope of work.[2]

6. **Phase 5 Design and Build (12-24 months):** the facilities are designed and construction is executed. Non-regulated customer connection projects are generally complex and can span multiple years. Execution therefore follows the scalable Transmission Capital Project Delivery Model discussed in TSP Section 2.11 to drive safe and efficient outcomes in context of the delivery of a large and complex transmission investment portfolio.

7. **Phase 6 Commissioning (1-2 months):** the connection facility is inspected, tested and placed in service. The CCRA is updated with the final actual costs and the customer is invoiced.

[2] Depending on scope, a project may be subject to completion of an Environmental Assessment in accordance with the *Environmental Assessment Act*, Leave to Construct approval from the OEB under Section 92 of the *Ontario Energy Board Act*, or real estate and property agreements.

Hydro One's connection process establishes a transparent, consistent and predictable path to complete non-regulated customer connection projects.

4.0 OUTCOMES

4.1 OEB RRF OUTCOMES

Table 1 below presents anticipated benefits from the investment in accordance with the OEB Renewed Regulatory Framework.

Table 1 - Outcome Summary

OEB RRF Outcome	Anticipated Benefits
Customer Focus	• Satisfy customer request for additional capacity
Operational Effectiveness	• Increase capacity as requested by large commercial or industrial customers.
Public Policy Responsiveness	• Comply with Hydro One's obligations under its Transmission Licence to provide customers with non-discriminatory access.

5.0 EXPENDITURE PLAN

Table 2 below summarizes Hydro One's forecast total capital expenditures under this investment for the 2028-2032 planning period. See Appendix B for a summary of the investment expenditures by non-regulated customer connection project.

Final project costs are recoverable through incremental revenue from the appropriate rate pool and any customer capital contributions under the CCRA. Customer capital contributions under the CCRA may not be required when project costs are fully recovered through incremental revenue. The capital contributions are determined pursuant to Hydro One's Transmission Connection Procedure in accordance with the TSC. Project costs and capital contribution amounts are subject to true-up once the project is placed in-service, subject to the terms of the CCRA. CCRAs allow Hydro One to recover the actual costs incurred even if a customer elects to cancel a project.

Table 2 - Hydro One Investment Expenditures[3,4]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	117.7	69.3	42.4	1.0	0.0	230.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions	52.7	13.8	0.0	0.0	0.0	66.5
Net Capital Expenditures	**65.1**	**55.5**	**42.4**	**1.0**	**0.0**	**163.9**

6.0 ALTERNATIVES

Appendix A provides a discussion of alternatives for each non-regulated customer connection project under this investment.

7.0 EXECUTION RISK AND MITIGATION

Under the Transmission Capital Project Delivery Model, discussed in TSP Section 2.11, project risks are identified and mitigation plans are implemented. Risks that can impact the completion of non-regulated customer connection projects include the following:

- Outage Constraints: Planned outages are required to replace and construct assets. Outages may impact individual assets, sections of a station or transmission line, or the entire station. Also, when industrial customer project volumes exceed forecast, Hydro One remains obligated to complete the demand projects which introduces new risk to outage planning. Outage risk is minimized by ongoing collaborative planning and advanced coordination among stakeholders to minimize customer impact and the requirement for work reprioritization.
- Resource Constraints due to Increased Work Volumes: Hydro One plans resources for the known and forecasted volume of industrial customer connection projects. Volumes of work above forecast causes resourcing risk because all transmission station projects use the same teams of management and engineering resources and projects in the same geographical location use the same teams of construction and commissioning resources. Resourcing risk is mitigated by the availability of flexible casual resources and contracted resources, which can commence work on short notice and relieve peak periods.

[3] Forecast net capital expenditures for the 2028-2032 period include $12.9M of immaterial projects.
[4] Figures presented in the tables may not sum to the totals shown due to rounding.

- Construction Execution Challenges: Existing station equipment may require retrofits to accommodate new assets because station design and equipment standards have evolved. Significant design and construction are required if modification cannot be completed in the same physical location due to space constraints, outages or safety consideration. This risk is mitigated by early identification of project constraints during phases one to three of the connection process to identify alternatives.
- Real Estate Requirements: Station or transmission line right-of-way expansion and new land may be required when assets cannot be replaced in the same physical location. This risk is mitigated by early identification of project constraints during phases one to three of the connection process to identify alternatives.
- Environmental Assessment, First Nation Consultation and Community Engagement: New land requirements trigger environmental assessment, First Nation consultation and community engagement. Hydro One undertakes early engagement with stakeholders to ensure their concerns and identified risks can be communicated and addressed.

APPENDIX A - DESCRIPTION OF FORECAST INVESTMENTS

This Appendix provides the scope for each investment and summarizes the alternatives considered.

ISD Ref.	Investment Name	Scope Summary	Alternatives	Total 28-32 ($M)	Project Total ($M)
T-SA-12.01	Large Load Connection	Execution of 230kV switchyard expansion at Hydro One's Parkway TS and installation of two new 230kV underground cable circuits from Parkway TS to the new customer constructed Customer-Owned Transformer Station (CTS); Parkway TS 230kV switchyard expansion would consist of two new diameters, each consisting of two breakers and associated necessary switchgear and protections to connect two new 230kV supply circuits; the two new 230kV cable circuits would need to be routed and installed between Parkway TS and the new customer CTS which are approximately 2km apart; the investment is required to facilitate a load request from an industrial customer to provide increased capacity to supply their planned facility; the existing 230kV lines infrastructure in the area does not have sufficient capacity to supply the requested peak load. Prior to 2028, project development is anticipated to be underway and capital contributions commenced toward Hydro One's total capital expenditures.	1. *Status Quo (rejected)* Would not meet customer load growth needs; not aligned with Hydro One's Transmission Licence nor the TSC 2. *Complete Two 230kV Connections and Switchyard Expansion (recommended):* The forecasted amount of new load is large and thereby necessitates the need for two new supply circuits.	95.4	83.9

T-SA-12.02	Large Load Connection	Execute tapping of 230kV N37S and N5M circuits between Hydro One's Nanticoke TS and Middleport TS and construct two new line-taps of 7km from each circuit to the customer's facility; the investment is required to facilitate the request from a large load customer to provide supply to their planned facility which will have 450MW of load; customer will build its own CTS. Prior to 2028, Hydro One expects to begin the line route selection and estimation process that includes necessary engineering work required for developing an estimate.	1. *Status Quo (rejected)* Would not meet customer load growth needs; not aligned with Hydro One's Transmission Licence nor the TSC 2. *Tapping N21J/N22J Circuits Providing Two New 230kV Connections (rejected)* These circuits do not have sufficient capacity to meet the customer need without violating the IESO's planning criteria 3. Tapping 230kV N37S and N5M Circuits *Providing Two New 230kV Connections (recommended)* Only practical alternative to satisfy the customer request	32.0	46.0
T-SA-12.03	Large Load Connection	Construct two 3km line taps owned and operated by Hydro One approximately 13.5 km west from Detweiler TS to connect first CTS; complete two 2.5 km-3 km line taps owned and operated by Hydro One approximately 14 km north from Detweiler TS to connect second CTS; the investment is required to facilitate the request from a large load customer to provide supply to their planned facility which will have 400MW of load; customer will build the two CTSs . Prior to 2028, Hydro One began preliminary engineering.	1. *Status Quo (rejected)* Would not meet customer load growth needs; not aligned with Hydro One's Transmission Licence nor the TSC 2. *Supply Two New CTSs From Nearby 230kV Circuits by customer owned taps (rejected)* Customer preference was for Hydro One to construct, own, and operate the line taps. 3. *Supply Two New CTSs From Nearby 230kV Circuits by Hydro One owned taps (recommended)* Only practical alternative, given the proximity to transmission corridors and capacity available on the circuits.	23.6	59.3

APPENDIX B - SUMMARY OF INVESTMENT COSTS

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

Table B1 - Hydro One Detailed Material Investment Costs ($M)

ISD Ref.	Investment Name		Net Capital Investment							Planning Period		
			23-27 Total	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year
T-SA-12.01	Large Load Connection	Capital Contributions	-13.3	-13.6	-13.8	0.0	0.0	0.0	-27.4	P	83.9	2030
		Net Capital Expenditure	-11.5	3.1	52.0	40.4	0.0	0.0	95.4			
T-SA-12.02	Large Load Connection	Capital Contributions	-8.0	-21.0	0.0	0.0	0.0	0.0	-21.0	P	46.0	2028
		Net Capital Expenditure	14.0	32.0	0.0	0.0	0.0	0.0	32.0			
T-SA-12.03	Large Load Connection	Capital Contributions	-3.7	-18.0	0.0	0.0	0.0	0.0	-18.0	P	59.3	2028
		Net Capital Expenditure	35.7	23.6	0.0	0.0	0.0	0.0	23.6			

T-SR-01	**TRANSMISSION STATION RENEWAL – NETWORK STATIONS**
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	169.8	104.5	97.5	163.8	159.6	695.3

Summary:

This investment involves the replacement of critical transmission station assets at network stations that have deteriorated to poor condition, thereby posing reliability, safety and environmental risks. The primary triggers of the investment are deteriorated condition, high risk of asset failures, and the need to maintain bulk transmission system reliability. The investment is expected to reduce the risk of reduced supply reliability and customer outages due to equipment failures.

1.0 OVERVIEW

Network stations are transmission stations connected to the Bulk Electric System (BES), which links major generation resources to major load centers and serves as the backbone of the Ontario electricity system. The BES is a large interconnected electrical system, consisting of transmission network stations, 500 kV, 230 kV and 115 kV high-voltage transmission lines, and generation facilities. The North America Electric Reliability Corporation (NERC) develops reliability standards applicable to the BES in North America to ensure reliability and adequacy. The IESO, as Ontario's Reliability Coordinator, monitors and ensures all market participants in Ontario, including Hydro One Transmission, comply with applicable reliability standards. NERC reliability measures require that the BES meets all expected demand under normal conditions and reasonably predictable contingencies. The BES must maintain a balance of generation and demand at any moment in time and protect equipment from physical damage when any disturbances occur to quickly restore the system. Hydro One's network stations are necessary for the reliable operation of the BES and Ontario's transmission network. As a licensed transmitter operating transmission facilities greater than 100 kV, Hydro One is obligated to comply with the planning, operating and reliability criteria and standards mandated by NERC and Northeast Power Coordinating Council (NPCC). Furthermore, Hydro One transmission customers include large electricity generators, large industrial end-users and the majority of Ontario's LDCs.

The Transmission Station Renewal – Network Stations investment manages asset-failure related risks to station performance and operational effectiveness with the replacement of key station assets that have been verified to be in poor condition. This investment involves a series of individual investments and includes the replacement of multiple assets within a particular station. The scope of each investment includes renewal of poor condition transformers, breakers, switchgear, and protection and control systems. Investments may also include other station assets, such as instrument transformers, disconnect switches and other ancillary equipment, as and where required. The list of stations and details for each individual investment comprising the investment are provided in Appendix A below.

Hydro One's network stations provide the necessary transmission system structure to power the provincial economy and meet society's daily needs. The main customers served

at network stations are large generation customers, LDCs and large industrial customers. Not proceeding with this investment would result in leaving aged and poor condition assets in-service and increasing the risk of equipment failure resulting in safety hazards, environmental damage and unplanned outages impacting customers. Operational risks include bottled generation, reduced transfer capability and restricted power flows. If these risks were to materialize, such events could prevent generation customers from supplying electricity to the transmission system or could prevent Hydro One from meeting the loading needs of LDC customers. This is not the level of service Hydro One customers expect from their transmitter and would not meet the standards mandated by NERC and NPCC. Where multiple critical assets require replacement and station-wide coordination is needed, Hydro One may employ an “integrated station approach” to renew major power system equipment through a single project in coordination with broader regional or bulk system needs. Ancillary equipment in need of replacement will also be included. This approach maximizes outage efficiency, reduces customer disruptions, and provides opportunities for station modernization, reliability improvements, and configuration enhancements.

Given the combination of regulatory requirements and the critical role of electricity in Ontario’s homes, businesses, and institutions, Hydro One cannot run its transmission assets to failure. Hydro One’s priority is to maintain transmission facilities in-service. Accordingly, the proposed renewal spending is anchored on replacing assets based on their condition. To optimize the amount of risk mitigated in the pacing of investments, Hydro One prioritizes investments in terms of total risk mitigation, risk spend efficiency, and contribution to desired outcomes, as detailed in SPF Section 1.7.

2.0 INVESTMENT NEED

The investment focuses on the replacement of poor condition transmission station assets that facilitate power transformation from a high transmission voltage to a lower transmission voltage. Operating assets that are in poor condition pose an increased risk of failure or of failing to execute operations as intended. Transformers may catch fire resulting in safety hazards, extensive damage and oil spilling on and off-site into the neighbouring environment. Breakers may fail to operate (open) when needed, as they are intended to, or they may experience insulation failure leading to internal arcing during

operation, causing irreparable damage. Failures of critical assets may result in damage to connected equipment, impacts to system stability, interruptions to generation connections with significant durations, employee and public safety risks and environmental impacts.

As discussed in TSP Section 2.1, Hydro One is a member of the Northeast Power Coordinating Council (NPCC) registered under NERC's compliance registry. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards adopted by NERC and NPCC. These standards and criteria require adequate and secure supply over a wide range of conditions so that loss of one or more elements (line or station asset) will not result in any violation of thermal and stability limits. This means that a failure of one of two transformers or circuits supplying a delivery point does not impact service to customers (i.e., supply continues uninterrupted from the remaining transformer or circuit). Nonetheless, such failures are a major concern for Hydro One, the IESO and the LDCs that are being supplied, because the occurrence of a second asset outage prior to the failed asset being replaced (which could take considerable time) could result in a lengthy delivery point interruption. When replacing assets to address condition-related risk or system requirements, Hydro One may have no choice but to make upgrades since like-for-like replacement may not match current NERC standards.

As discussed in TSP Section 2.2.1, even when there is no immediate customer interruption, forced outages can have other impacts on Hydro One's transmission system including decreased redundancy, increased wear and tear on other assets, and the cancellation or rescheduling of planned outages for maintenance, repair, and replacement work. This is not the service performance that customers (generation customers, industrial customers and downstream Local Distribution Companies) expect from Hydro One.

Leaving poor condition transmission station assets in-service also increases the risk of catastrophic failures, which pose a safety risk for Hydro One staff and the public. Major transformer failures have been key drivers of prolonged outage durations. For example, Hawthorne T3 (a 500–230kV autotransformer) failed in 2022 after severe gassing beyond repair and required a demand replacement that took ten months. Each time a transformer fails, and redundancy is lost for months, the system remains exposed and any subsequent

failure of the companion transformer can lead to severe consequences for load and customers. Therefore, minimizing unplanned transformer failures is critically important to maintaining system reliability and customer service.

The condition of transformers and breakers, and the age of protection and control systems are the leading indicators of the assets' performance that may eventually lead to catastrophic events, such as the one described above. Given the criticality of transmission assets, Hydro One does not run them to failure. Asset deterioration is not reversible and cannot be stopped. Hydro One has a significant amount of assets that have been verified to be in poor condition. In addition, there is a large population of transmission assets that are in fair condition, meaning that there is some form of deterioration. This population of assets will eventually degrade to the poor condition category as the condition of the asset continues to deteriorate over time. Key station asset demographics and condition are further described below.

TRANSFORMER CONDITION – NETWORK STATIONS

As discussed in TSP Section 2.2.2.1, transformer condition is a leading indicator of performance and the main driver for replacement. Transformer condition can be impacted by several factors including loading history (i.e., the amount of power it must transform), age, weather exposure, and operating conditions. If a transformer experiencing some deterioration is highly loaded, it is likely to deteriorate faster than if it carries a lower load.

A transformer's load profile can depend on the station's design and the load the transformer is expected to carry during normal and temporary conditions. In a station with two transformers, one of the transformers may be required to temporarily carry a higher load as a result of an extended (planned or forced) outage of the companion transformer. Under this scenario, the remaining in-service transformer (which likely has characteristics that are similar to the companion unit and both have been subjected to similar environmental conditions and loading) would be required to bear the full load of both transformers and therefore experience further condition deterioration as a result.

The overall condition of a transmission transformer is evaluated based on a detailed condition assessment using the most recent condition data as well as historical data

relating to four main indicators: (i) insulation deterioration within the main tank, (ii) oil leaks, (iii) cooling system failure, and (iv) tap changer malfunction.

By operating a large number of poor condition transformers, there is an increase in system reliability risk as this equipment tends to have a higher probability of failure. An assessment of the network station transformer fleet's condition shows that approximately 49 (29% of transformers located within network stations) are rated in poor condition. More information on asset demographics, condition and other factors can be found in TSP Section 2.2.

BREAKER CONDITION – NETWORK STATIONS

Similar to transformers, breaker condition is a leading indicator of expected performance. Poor condition breakers can ultimately result in outages and severely impact system stability, the operations of other connected equipment, and employee and public safety. Asset condition is determined through preventive maintenance including diagnostic testing and inspections and is a major driver for breaker replacement as part of the investment.

As discussed in TSP Section 2.2.2.2, circuit breakers use different interrupting mediums such as oil, air, and SF_6 gas to extinguish electric arcs during operation. For air and SF_6 breakers, these gases must be kept at high pressure to work effectively. As breakers age, their O-rings and gaskets deteriorate, leading to SF_6 leaks. When this happens, the internal pressure drops and moisture can enter the equipment. Both reduced pressure and moisture lower the breaker's dielectric strength, weakening its ability to quench arcs. This increases the risk of internal flashover, which in severe cases can result in an explosive breaker failure.

In addition to condition, the presence of obsolescence can necessitate the replacement of assets that might otherwise remain operational. Obsolescence creates reliability and maintainability risks, such as limited availability of spare parts, discontinued manufacturer support, and the inability to safely or effectively perform modern testing, diagnostics, or repairs. These risks can materially increase the likelihood and consequence of in-service failures over time.

Similar to transformers, operating a large percentage of the fleet that is in poor condition increases system reliability risk as this equipment tends to have worse performance and a higher probability of failure. The assessment of the network station breakers' condition shows that approximately 109 (6% of the breakers located within network stations) are rated poor condition. More information on asset demographics, condition and other factors can be found in TSP Section 2.2.2.2.

Hydro One has 2,061 breakers, or 44% of the overall fleet, that are considered obsolete, with approximately 545 breakers, or 11% of the overall fleet, no longer supported by vendors and where aftermarket parts are not available or are costly to acquire or fabricate. Where parts are difficult to procure, specific units are replaced so the decommissioned units can serve as strategic spares for the remaining in-service fleet, but that is currently not feasible for approximately 11% of the overall fleet.

Hydro One's approach with respect to the replacement of breakers is a targeted, risk-based approach that prioritizes the renewal of breakers most likely to impact safety, reliability, or maintainability. Breakers are selected for replacement based on deteriorated condition, obsolescence, vendor support, environmental impact, system criticality, and overall safety risk.

Table 1 below provides a summary of the main reasons and need for asset replacement based on the breaker type.

Table 1 - Reasons for Breaker Replacement by Breaker Type

Type of Breaker	Reason for Replacement
Oil Breaker	• Condition and reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • Non-compliance with current system operating ratings • Current rating changes
Air Blast Breakers	• Significant negative impact on outage frequency • Deteriorating condition and performance • Obsolescence due to lack of vendor support and unavailability of maintenance parts • Elimination of high maintenance costs

SF6 Breakers	• Condition and reliability concerns • First generation SF6 breakers • Obsolescence due to lack of vendor support and unavailability of maintenance parts • SF6 emissions • Current rating changes
GIS Breakers	• Reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • SF6 emissions
Metalclad	• Arc flash hazards • Obsolescence due to lack of vendor support and unavailability of maintenance parts
Vacuum	• Obsolescence due to lack of vendor support and unavailability of maintenance parts

A major driver for replacement is ensuring breakers have adequate short-circuit interrupting capability. As new customer connections, system upgrades, and network reinforcements alter fault levels, Hydro One conducts project-specific short-circuit studies as part of the IESO Connection Assessment and Approval process. Where short-circuit level ratings are exceeded, breakers need to be upgraded to a higher short-circuit rating, since operating beyond the nameplate rating can cause the breaker to fail.

Overall, this strategy ensures Hydro One systematically transitions high-risk and obsolete breaker fleets to modern, reliable, and supportable technologies while aligning capital investments with system needs and maximizing risk reduction.

PROTECTION EQUIPMENT DEMOGRAPHICS – NETWORK STATIONS

In contrast to other major power system assets like transformers and circuit breakers (which are replaced based on the condition of the equipment), the ESL of protection devices plays an important role in the assessment of replacement needs for protection relays. This is because assessment for physical breakdown or loss of strength over time is not feasible or relevant given the make-up of these electronic or solid-state devices. As such, to prevent the potentially significant reliability and safety impact of a sudden failure, ESL is necessarily a key trigger for further evaluation to confirm replacement needs.

As explained in TSP Section 2.2.2.3, there are 3,329 (approximately 26% of the total population) Hydro One protection systems operating beyond ESL. Such devices are subject to an elevated risk of failure, while also having very limited or no support from vendors in terms of replacement units, spare parts, and engineering and firmware support. As such, reactive repairs may involve extended durations as re-engineering and construction work will be required to install new devices based on different technology. These risks could lead to prolonged outages for customers. More information on asset demographics, condition and other factors can be found in TSP Section 2.2.2.3.

As explained in TSP Section 2.1, some network stations include assets designated as part of the Bulk Electric System (BES). With respect to protection and controls, to comply with NERC and NPCC reliability standards these BES stations are equipped with multiple, redundant and robust protection and control systems. These systems ensure that faults are isolated to prevent cascading failures and damage to assets near the fault. Infrastructure for key sites and processes is designed to adhere to NERC Critical Infrastructure Protection (CIP) requirements. NERC and/or NPCC standards require additional equipment, such as protection systems and station battery systems, and sites must meet additional CIP requirements, such as physical and electronic/cybersecurity to prevent unauthorized network access. When replacing assets to address condition-related risk or system requirements, investments may have no choice but to make upgrades since like-for-like replacement may not match current NERC standards.

3.0 INVESTMENT DESCRIPTION

As discussed above, this investment focuses on the replacement of multiple network station assets that facilitate power transformation from a high transmission voltage to a lower transmission voltage. This integrated station approach focuses on a particular station where multiple key station assets require replacement, as driven by their condition, and investments may be accompanied by some level of electrical reconfiguration to address operating concerns and customer preferences or to standardize the installed equipment.

As described in SPF Section 1.7 and TSP Section 2.7, Hydro One performs an asset risk assessment and, if as a result of this assessment, Hydro One identifies multiple assets that are in poor condition, then this station is subsequently identified as a candidate investment. All candidate investments identified for replacement undergo the risk-based prioritization assessment to determine whether they need to be included in the investment Plan. As a result of the investment planning process, over the 2028-2032 period, the investment targets 31 material investments at network stations and addresses the replacement of 33 transformers (19 to be in-serviced during the 2028-2032 period), 88 breakers (88 to be in-serviced during the 2028-2032 period), and 471 protection systems (450 to be in-serviced during the 2028-2032 period). While Hydro One has a significant number of transmission station assets that are in poor condition, this investment primarily addresses critical and pressing issues that require attention. Hydro One will also address other minor station assets (e.g., ancillary equipment) where condition warrants replacement as well as any potential site and property issues, customer issues, safety and/or environmental concerns. A detailed list of assets planned for replacement is presented in Appendix A below.

Hydro One also performs functional reconfiguration and station right-sizing analyses to ensure alignment with load forecasts and applicable industry and regulatory standards. Functional reconfiguration is the reconnection of power system elements (e.g. breakers, transformers) within a transmission station into a new electrical configuration. This can either better facilitate a customer connection, a connection to the bulk power system or help eliminate operational restrictions or limitations which can aid in the transfer or restoration of power during a faulted condition where an element is removed from service.

Functional configuration and station right-sizing, where possible, allows Hydro One to replace two smaller rated transformers with a single standardized transformer that delivers the same capacity. This helps Hydro One maintain a standardized catalogue of power equipment to minimize the various types of spare equipment required.

Hydro One customers broadly support the replacement of deteriorating transmission stations assets. As described in SPF Sections 1.6 and 1.7, and TSP Section 2.7, Hydro One actively works with its customers to capture their needs and preferences and implement the necessary changes to Hydro One designs, where feasible, to meet those needs. In conjunction with its planning process, Hydro One carried out a comprehensive, two-phase customer engagement to inform the development of investment strategies and candidate investments, including the pacing of transmission station and lines reinvestment. Across all customer types, customers chose the draft plan as their preferred option for replacing transmission station assets in poor condition. In regard to replacing aging transmission stations, Hydro One's customers expressed support for the replacement of aging and deteriorating transmission station assets to maintain the overall health of the system. Hydro One's investment plan addresses aging and deteriorated assets and has been optimized to sustain the current performance of the transmission system, matching customers' expectations.

4.0 OUTCOMES

As a result of the investment, Hydro One will reduce operational risks associated with the operation of equipment in poor condition; ensure compliance with the Ministry of Environment, Conservation and Parks in regard to oil spills, NERC and NPCC requirements; maintain long-term bulk system reliability; eliminate operational concerns through reconfiguration; and reduce constraints on generation resources.

4.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 2 - Outcomes Summary

Customer Focus	• Maintain reliable power delivery at network stations
Operational Effectiveness	• Improve the operational effectiveness of network stations through reconfiguration and standardization of new equipment and design
Public Policy Responsiveness	• Ensure compliance with applicable regulatory requirements

5.0 EXPENDITURE PLAN

As discussed above, the investment is needed to replace various network station assets that are in poor condition, which may lead to unexpected failures. Hydro One planned the investment to achieve completion as effectively and efficiently as possible.

Table 3 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 rate period.

Table 3 - Hydro One - Investment Expenditures[1,2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	193.0	113.1	109.1	174.0	173.7	763.0
Less Removals	7.3	3.5	2.2	3.4	3.5	20.0
Less Capital Contributions	15.9	5.1	9.3	6.8	10.6	47.7
Net Capital Expenditures	169.8	104.5	97.5	163.8	159.6	695.3

Hydro One forecasts total expenditures over the 2028-2032 period to be $695.3M, $334M less than the 2023-2027 period. This variance is primarily attributable to the nature and size of the projects being undertaken. The lower level of forecast expenditures in the 2028-2032 rate period, relative to the 2023-2027 period, is primarily driven by the composition and scope of the planned project portfolio. The variability of expenditures in this

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] Forecast net capital expenditures for the 2028-2032 period include $28.6M of immaterial projects.

investment does not reflect a single large material project, but rather the cumulative impact of multiple system investments at various stations reaching execution and commissioning stages within the same period.

The trend in net capital expenditures includes the impact of the inflationary pressures experienced by Hydro One during the 2023-2027 period relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historic material cost escalation trends are described in SPF Section 1.8.3, including power transformers and high voltage circuit breakers, which have increased by 115% and 140% on average, respectively, since 2020.

The factors influencing the cost of the investment include:

- The number of transformers, breakers, protection systems, and ancillary equipment being replaced
  - Higher voltage transformers and breakers and ancillary equipment are more costly from a material perspective as is the overall installed cost due to required clearances for high voltage equipment.
- Applicability of Ministry of the Environment, Conservation and Parks (MECP) requirements
  - Where stations are subject to environmental work (i.e. spill containment and/or oil water separators are required) increased costs may be incurred to facilitate the work required to meet the requirements.
- The complexity of project staging and outages required to facilitate work
  - Project costs increase with project complexity, including the number of interconnections and required outages.
- Whether the investment is a greenfield replacement or in-situ replacement requiring complex contingency planning
  - Generally, if space permits, either within the existing station fence or nearby, a greenfield solution may be less costly as it can be constructed with minimal interference to daily operations.

  - In situ replacement is generally more difficult, from both engineering design and construction perspectives as other equipment will need to be removed from service to facilitate construction and ensure safety and appropriate clearances. This increases the time required for construction and can impact customers as they will be supplied from only a single supply during these times.
- The location of the station, whether in an isolated rural area or congested urban area
  - Generally working in a congested urban station will increase costs and lengthen the overall construction time of the project with respect to clearances in order to work safely.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred option.

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENT

Reactive component replacement involves waiting for poor condition transformers, breakers, or ancillary equipment to fail and replacing components on a reactive basis. Hydro One does not run transmission assets to failure given their criticality to the integrity of the transmission system and the significant reliability, safety and environmental impact associated with their failures. This alternative is more costly not only for Hydro One but also for impacted customers. Hydro One has rejected this alternative for the following reasons:

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. When a critical asset fails, redundancy is lost for several months. In the case where a subsequent failure of a companion unit occurs, the consequences could be significant to the transmission system. Such a failure would be prolonged and result in extended equipment and customer outages which will subsequently negatively affect Transmission System Average Interruption Duration Index (SAIDI) and Transmission System Average Interruption Frequency Index (SAIFI) performance.

- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would result in constant reprioritization of planned work and inefficient redeployment of resources.
- Replacing failed components on a reactive basis would leave network stations in non-standard arrangements and possible non-compliance with reliability standards.
- This alternative limits the ability to account for future requirements and has a high risk of re-work and future additional costs.
- This strategy is likely to increase operating and maintenance costs, decrease equipment performance and may impact the safety of personnel on site.

ALTERNATIVE 2: PLANNED REPLACEMENT OF STATION ASSETS (RECOMMENDED)

Planned replacement of station assets is the preferred option for this investment.

Unlike reactive replacement following asset failure, the planned replacement of station assets allows Hydro One to address identified asset risks before failures occur. This approach reduces the reliability, safety, environmental and operational risks associated with continuing to operate deteriorated transmission station assets in service or relying on reactive replacement.

During the development of a station renewal investment, Hydro One assesses the condition and replacement needs of station assets and identifies the scope required to address the risks associated with assets in poor condition. Planned renewal also provides an opportunity to assess operational improvements and station right-sizing requirements, which may include changes to station configuration, supply voltage, transformer

arrangements or equipment standardization to support customer needs and operational requirements.

This alternative is recommended because it addresses identified asset risks before failure while allowing Hydro One to incorporate asset condition information, customer requirements and operational considerations into the investment. Relative to reactive replacement, it provides a more effective approach to maintaining the reliability, safety and long-term performance of Hydro One transmission stations.

7.0 EXECUTION RISK AND MITIGATION

As described in TSP Section 2.11, Hydro One follows a Transmission Capital Project Delivery Model, throughout which project risks are identified, and mitigation plans are implemented. Risks that can impact the completion of transmission station renewal projects at network stations include:

- Outage constraints: Planned outages are required to replace assets and may involve individual assets, sections of a station, or the entire station. Hydro One plans and coordinates outages to minimize impacts on customers while providing construction and commissioning staff with the access required to complete the work.
- Resource constraints: Projects in the same geographical location may require the same construction and commissioning resources. Hydro One coordinates project schedules and resource requirements to manage competing demands for these resources.
- Construction execution challenges: Existing station equipment may require retrofits to accommodate new assets because station designs and equipment standards have evolved. Significant design and construction may also be required where assets cannot be replaced in the same physical location due to space constraints, outage requirements or safety considerations.
- Customer coordination: Hydro One coordinates with customers to manage required outages and minimize customer impacts.
- Real estate requirements: Station expansion and new land may be required when assets cannot be replaced in the same physical location.

- Procurement challenges: Equipment procurement lead times can be long. Hydro One engages vendors at appropriate times in the planning process to ensure sufficient lead time to obtain major equipment.

APPENDIX A – DESCRIPTION OF FORECAST INVESTMENTS

This Appendix describes each material investment and forecast capital expenditures for the 2028-2032 period.

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
T-SR-01.08	Lakehead TS	This investment involves the replacement of 230 kV circuit breakers, 115 kV oil circuit breakers, associated disconnect switches, and the protections and controls system at Lakehead TS. This investment is needed to address poor condition and/or obsolete assets at Lakehead TS. This investment is expected to maintain reliability of supply to the Bulk Electric System and Hydro One customers in the Northern Ontario region.	0	14	48	23.9	70.6
T-SR-01.11	Marathon TS	This investment involves the replacement of 230kV circuit breakers, 115kV circuit breakers, AC and DC station service equipment, instrument transformers, and protection relays. The investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to the bulk system and local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	7	12	5.3	35.9
T-SR-01.12	Wawa TS	This investment involves the replacement of 230/150kV autotransformers, 230kV breakers, 115kV breakers, disconnect switches, instrument transformers, oil water separator system, and the AC station service system. The investment is needed to address assets in poor condition or that are obsolete, as well as re-terminating the 230 kV circuits. The investment is expected to maintain existing bulk network system reliability and load serving capability of the system and is not meant for system capacity increase purposes. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	7	27	18.8	102.2

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
T-SR-01.13	Lakehead TS	This investment involves the replacement of the C8 condenser with a new SVC Shunt Voltage Capacitor. The investment is needed to address assets in poor condition. This investment is expected to maintain reliability to the bulk network system and mitigate the risk of outages and supply interruptions due to asset failure.	0	0	2	11.6	53.3
T-SR-01.19	Des Joachims TS	This investment involves the replacement of protection and control equipment. This investment is needed to address protection and control equipment that is obsolete. This investment is expected to mitigate risk of equipment failure and maintain supply reliability to Hydro One Distribution customers in the area.	0	0	23	9.1	9.1
T-SR-01.20	Otto Holden TS	This investment involves replacement of 230 kV/115 kV autotransformers (single-phase units), 115kV breakers, associated disconnect switches, station service, DC station service and transfer scheme, and protection, control and telecom relays. This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to the local customers; and is not expected to increase capacity. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.	2	4	21	7.1	100.6
T-SR-01.22	Manby TS	This investment involves the replacement of autotransformers and protections at Manby TS. This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to reinforce the transmission system in the area, maintain reliability to the bulk system, and mitigate the risk of outages and supply interruptions due to asset failure.	3	0	86	93.1	140.1

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
T-SR-01.23	Fort Frances TS	This investment involves the replacement of a 230/115kV auto transformer, 115kV breakers, disconnect switches, protections, and a new oil water separator system. The investment is needed to address assets in poor condition and that are obsolete. The investment is expected to maintain existing system reliability and load serving capability of the system and is not meant for system capacity increase purposes. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	0	0	11.5	47.1
T-SR-01.24	Merivale TS	This investment involves the replacement of transformer T22, 230 kV circuit breakers, 115 kV oil circuit breakers, associated disconnect switches, and the protections and controls system at 40 year old Merivale TS. This investment is needed to address poor condition and/or obsolete assets at the Merivale TS. This investment is expected to maintain reliability of supply to the Bulk Electric System and Hydro One customers in the Ottawa region.	1	34	80	23.5	169.7
T-SR-01.25	Beach TS	This investment involves the replacement of autotransformers along with the associated transformer disconnect switches and protection devices. This investment is needed to address the autotransformers that are in poor condition. The replacement of these assets is necessary due to the crucial role they and Beach TS play in regional power flows in the Hamilton-Niagara region. This investment is expected reinforce the transmission system in the area, maintain reliability to the bulk system and major industrial customers and mitigate the risk of outages and supply interruptions due to asset failure.	3	0	8	6.2	71.5
T-SR-01.26	Lennox TS	This investment involves the replacement of 500/230 kV, 450/600/750 MVA autotransformer T51 along with other station assets such as transformer spill containment, AC station service, and associated protection and control equipment at a 35 year old Lennox TS. This investment is needed to address poor condition and/or obsolete assets at the Lennox TS. This investment is expected to mitigate risk of	1	0	0	6.2	20.3

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
		equipment failure and maintain supply reliability to Hydro One distribution customers in the Lennox/Napanee area.					
T-SR-01.27	Buchanan TS	This investment involves 230kV autotransformers, spill containment pits, AC and DC station service equipment, and protection, controls and telecom equipment. This investment is needed to address equipment that is in poor condition or is obsolete. The investment will allow Hydro One to ensure bulk power system reliability is maintained and not impacted by failing assets.	2	0	6	33.4	41.7
T-SR-01.28	Owen Sound TS	This investment involves the replacement of transformers, disconnect switches, LV switchyard components including breakers, station services, capacitors, and protection and control equipment. This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability and is not meant for system capacity increase purposes. The benefits of this investment are mitigation of risk associated with equipment in poor condition and removal of obsolete equipment.	1	1	14	24.2	24.2
T-SR-01.29	Kenora TS	This investment involves replacement of an autotransformer, associated disconnect switches and a station service transformer. The investment is needed to address the poor condition of the autotransformer. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity.	1	0	2	15.8	15.8
T-SR-01.31	Hawthorne TS	This investment involves the replacement of oil-filled circuit breakers, the associated disconnect switches, and protection and control equipment. This investment is needed to address poor condition and/or obsolete assets at the Hawthorne TS. This investment is expected to mitigate risk of equipment failures and maintain supply reliability to Hydro Ottawa customers in Ottawa area.	0	8	46	50.3	62.5

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
T-SR-01.32	Cataraqui TS	This investment involves the replacement of autotransformers, breakers and protection equipment. The investment is needed to address the autotransformers, protections and oil circuit breakers that are in poor condition and/or are obsolete. The investment is expected to maintain reliability of supply to the downstream 115kV system in eastern Ontario, decrease the risk of equipment failure and transformer losses, and meet present day Hydro One standards.	2	0	18	46.7	46.7
T-SR-01.36	Keith TS: PSR5	This investment involves replacement of a phase shifter and associated disconnect switches in poor condition, with the tap changer out of service. The international tie-line J5D on the 230 kV network connects into Detroit, Michigan via the Phase Shifting and Voltage Regulating Transformer. These asset upgrades will mitigate equipment failure risk, improve system reliability, as well as increase the ability to meet projected load flows.	1	0	0	10.0	52.6
T-SR-01.37	Milton SS; GIS	This investment involves the replacement of a 500kV gas insulated switchgear breaker and associated ancillaries at Milton SS. The investment is needed to address 500kV breaker with a damaged component that can not be replaced due to obsolescence. The investment is expected to alleviate the risk of equipment failures and subsequent station vulnerability on the bulk electric system at this critical station.	0	1	0	9.2	20.2
T-SR-01.38	Hunta SS	This investment involves the replacement of AC station service and protection equipment. The investment is needed to address the equipment that are in poor condition and/or are obsolete. The investment is expected to maintain reliability of supply between Pinard TS, Ansonville TS and Kirkland Lake TS. Upon completion, this project will mitigate equipment failure risk, remove identified obsolete equipment from the system and prevent a potential adverse impact on system reliability.	0	0	13	12.7	14.6

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
T-SR-01.39	Hanmer: Insulator	This investment involves the replacement of 500kV insulators at Hanmer TS. The investment is needed to address 500kV insulators in poor condition. The investment is expected to maintain reliability of the Bulk Power System, decrease the risk of equipment failure and maintain supply reliability to Hydro One customers.	0	0	0	15.5	21.5
T-SR-01.40	Pickering ASS	This investment involves the replacement of the DC Station Service and Instrument Transformers at Pickering TS. The investment is expected to decrease the risk of equipment failure and maintain supply reliability to Hydro One customers.	0	0	0	8.8	10.0
T-SR-01.41	Pickering BSS	This investment involves the replacement of the DC Station Service and Instrument Transformers at Pickering TS. The investment is needed to address 230kV Breakers, and protections that are in poor condition and/or obsolete. The investment is expected to maintain reliability of the Bulk Power System, decrease the risk of equipment failure and maintain reliability to with OPG Pickering Nuclear Generation Station.	0	12	40	56.7	75.2
T-SR-01.42	Chats Falls	This investment involves the replacement of Protection and Control equipment, switches and instrument transformers. The investment is expected to decrease the risk of equipment failure and maintain supply reliability to Hydro One customers.	0	0	10	13.0	13.0
T-SR-01.43	Hawthorne TS: TS Autotransformer Upgrade	This investment involves replacement of an autotransformer and associated disconnect switches. The investment is needed to address the poor condition of the autotransformer. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity.	1	0	0	50.0	50.0
T-SR-01.44	Hanmer TS	This investment involves replacement of an autotransformer and associated disconnect switches. The investment is needed to address the poor condition of the autotransformer. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity.	1	0	0	28.8	28.8

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
T-SR-01.46	Middleport TS: T3	This investment involves replacement of an autotransformer and associated disconnect switches. The investment is needed to address the poor condition of the autotransformer. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity.	1	0	11	39.6	51.9
T-SR-01.47	Marathon TS – T11 & T12	This investment involves replacement of an autotransformer and associated disconnect switches. The investment is needed to address the poor condition of the autotransformer. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity.	2	0	0	6.5	39.7
T-SR-01.48	Dryden TS	This investment involves replacement of an autotransformer and associated disconnect switches. The investment is needed to address the poor condition of the autotransformer. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity.	2	0	0	5.4	45.8
T-SR-01.49	Burlington TS	This investment involves replacement of autotransformers, step down transformers and associated disconnect switches. The investment is needed to address the poor condition of the autotransformer. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity.	3	0	4	6.8	59.6
T-SR-01.50	Dymond TS	This investment involves replacement of an autotransformer and disconnect switches. The investment is needed to address the poor condition of the autotransformer. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity.	2	0	0	5.8	49.7
T-SR-01.51	Porcupine TS: Cap Banks	This investment involves the replacement of capacitors and associated disconnect switches. This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability and is not meant for system capacity increase purposes. The benefits of this investment are mitigation of risk	0	0	0	11.6	36.3

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
		associated with equipment in poor condition and removal of obsolete equipment.					

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

The investments proposed in this ISD are complex and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.11. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project, the in-service year and the project total estimates for the 2023-2027 and 2028-2032 rate periods. Project maturity is defined by the following project phases:

- Execution (E), which reflects fully approved project work;
- Planning and Definition (P), which reflects non-execution work, regardless of level of upfront development; and
- Complete (C), which reflects that the project has been placed in service

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in the table below in reference to project total variances and overall project schedule variances.

1

Table B1 - Hydro One – Detailed Material Investment Costs ($M)

ISD Ref.	Project Name	Actual Pre 2023	Net Capital Investment ($M)							Project Forecast			Prior Project Forecast[3]			
			Act/Fcst 23-27[4]	2028	2029	2030	2031	2032	28-32 Total	Project Phase	Proj. Total	In Service Year	ISD Ref.	Prior Project Phase	Prior Proj. Total	Prior In Service Year
T-SR-01.01	Claireville TS	20.5	**16.1**	0	0	0	0	0	**0**	E	36.6	2026	-	E	27.9	2025
		Since the Plan[5] was prepared, the forecast cost of this project increased as a result of site-specific conditions such as space limitations and existing subsurface facilities, resulting in engineering design modifications as assumptions that were established during preliminary design changed. Additional cost increases resulted from outage constraints that led to multiple outage schedule changes and cancellations, causing project delays. Furthermore, the estimated cost of the project increased by approximately $3M due to cost escalation.														
T-SR-01.02	Seaforth TS	6.3	**65**	0.4	0	0	0	0	**0.4**	E	71.7	2027	-	P	53.6	2024
		This investment was in a preliminary planning phase when the original forecast for the Plan was established. Since the Plan was prepared, the forecast cost of this project increased as the estimate matured and scope evolved. Specifically, the project scope was refined to include location changes for all transformers, adjustments to maintain the current medium-voltage switchyard in order to avoid the cost of an entire replacement, and additional work discovered based on engineering assessments and studies. The estimated cost of the investment also increased due to cost escalation of approximately $9M. These cost escalations were partially offset by construction efficiencies, strong risk management, and partial in-servicing, resulting in an effective reduction in overall project cost by approximately $6M. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-01.04	Keith TS	31.7	**17.8**	0	0	0	0	0	**0**	C	49.3	2023	-	E	42	2023
		This investment experienced a cost variance due to design changes as a result of site-specific conditions, emergency replacement work for a transformer, and updated labour rate assumptions. Increased sundries, material handling expenditures, and additional contingency contributed to the variance as well.														
T-SR-01.06	Milton SS	6.3	**22.8**	0.3	0	0	0	0	**0.3**	E	29.4	2028	-	E	20	2024
		Since the Plan was prepared, the forecast cost of this project increased as a result of refinements to engineering deliverables following site visits and field verification activities that enhanced the understanding of site conditions and informed updates to preliminary design assumptions. Additional cost increases resulted from frequent outage schedule changes arising from unplanned equipment failures, causing project delays, as well as cost escalation.														
T-SR-01.07		18.5	**23.1**	0	0	0	0	0	**0**	E	41.6	2027	-	E	29.3	2024

[3] "Prior Project Forecast" refers to the forecast project total and in-service date when Hydro One revised the capital 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.
[5] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

	Rabbit Lake SS	Since the Plan was prepared, the forecast cost of this project increased as a result of design refinements and additions required after release for construction drawings were issued. This included redesigning wave traps, redesigning the switchgear interlocking scheme to mitigate safety issues, and rerouting a transmission line. Further cost increases were driven by execution challenges which stemmed from ongoing outage changes, constraints on qualified regional commissioning crews, and cost escalations. In addition, the investment experienced delays in 2023 and 2024 due to portfolio reprioritization and equipment failure. These cost escalations were partially offset by optimizing the outage staging plan which decreased rental costs and interest and overhead expenses resulting in an effective reduction in overall project cost by approximately $3M.														
T-SR-01.08	Lakehead TS	0.9	**45.8**	12.1	11.7	0.1	0	0	**23.9**	E	70.6	2028	-	P	38.8	2028
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-01.11	Marathon TS	1.2	29.4	5.3	0	0	0	0	5.3	E	35.9	2028	-	P	30.7	2026
		Since the Plan was prepared, the scope of this project increased due to expanded protection and control equipment investment. This included the addition of an extra set of line protection equipment and control upgrades to the remote terminal unit. The project total cost increase is also driven by cost escalation, particularly for breakers. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-01.12	Wawa TS	6.1	**77.4**	11.3	7.5	0	0	0	**18.8**	E	102.2	2028	-	P	60.1	2026
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-01.13	Lakehead TS	0.0	**41.7**	10.9	0.7	0	0	0	**11.6**	P	53.3	2028	-	P	45.3	2026
		This investment was deferred by two years, during which the estimate matured as Hydro One worked with the vendor to settle on commercial terms. The increased cost of the investment reflects current vendor pricing and cost escalation. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-01.16	Essa TS	0.0	**70.3**	0	0	0	0	0	**0**	C	70.3	2026	-	P	88.1	2027
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-01.17	Mackenzie TS	5.5	**55.4**	0	0	0	0	0	**0**	C	60.9	2025	-	P	47.3	2025
		This project experienced a cost variance due to cost escalation (approximately $3M), the procurement of an additional transformer to replace a spare (approximately $3M), and the introduction of the Waasigan project which changed the execution strategy. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan. Through strong risk management, contingency and interest were reduced with Hydro One effectively lowering the overall project cost by approximately $6M.														
T-SR-01.18	Algoma TS	0.2	**0.6**	0	0	0.4	0.6	2.3	**3.3**	P	25.8	2034	-	P	30.9	2027
		The project was descoped due to the rapid deterioration of the transformers causing an increased risk of imminent failure leading to their accelerated replacement under other investments. The remaining project scope has been deferred due to portfolio reprioritization.														

T-SR-01.19	Des Joachims TS	0.0	**0**	0.3	0.5	3.3	5	0	**9.1**	P	9.1	2031	-	P	6.6	2027
T-SR-01.20	Otto Holden TS	2.3	**91.3**	6.9	0.1	0	0	0	**7.1**	E	100.6	2028	-	P	68.7	2027
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-01.22	Manby TS	0.3	**46.8**	39.3	29.4	20.7	3.6	0	**93.1**	P	140.1	2030	-	P	64.3	2030
		This investment was in a preliminary planning phase when the original forecast for the Plan was established. Since the Plan was prepared, the scope of this investment increased due to the relocation of critical power system equipment located below grade to above grade, and station drainage upgrades. These modifications were incorporated after the 2024 flood to mitigate future interruptions. The station has experienced two major flooding events in the last decade with the most recent one interrupting approximately 900MW of power. The expansion of protection and control requirements which approximately doubled since the original scope was the largest contributor to the cost variance associated with the flood mitigation measures. Through construction efficiencies and scope optimization, savings were realized with Hydro One effectively reducing the overall cost by approximately $11M.														
T-SR-01.23	Fort Frances TS	0.8	**0.2**	0	0	0.7	1.4	9.4	**11.5**	P	47.1	2034	-	P	40.5	2027
T-SR-01.24	Merivale TS	1.7	**144.5**	15.7	7.8	0	0	0	**23.5**	E	169.7	2029	-	P	182.2	2027
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2. The investment at Merivale TS is comprised of two projects that are being executed together, a system renewal investment, as shown here, and a system service investment. The Detailed Individual Investment Variance Summary discusses the overall Merivale TS investment.														
T-SR-01.25	Beach TS	1.0	**61.4**	6.2	0	0	0	0	**6.2**	E	71.5	2028	-	P	61.3	2028
		This investment was in a preliminary planning phase when the original forecast for the Plan was established. Since the Plan was prepared, the forecast cost of this project increased as the estimate matured. This included contingency reflective of contract pricing derived from a recent bid process, replacing the standard unit costs that underpinned the prior plan amount, as well as actual project risks. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan. Through construction efficiencies, strong contract management, and in-service advancement, project savings were realized with Hydro One effectively reducing the overall project cost by approximately $14M.														
T-SR-01.26	Lennox TS	0.0	**14.1**	6.2	0	0	0	0	**6.2**	P	20.3	2028	-	P	31.7	2030
T-SR-01.27	Buchanan TS	0.0	**0**	0.5	0.5	3.9	12.1	16.4	**33.4**	P	41.7	2033	-	P	57.8	2030
		The purpose of the investment is to replace two transformers and other assets. Since the original forecast for the Plan was determined, the amount of assets to replace has decreased to include only those associated with the two transformers. The investment has also been deferred due to portfolio reprioritization.														

T-SR-01.28	Owen Sound TS	0.0	**0**	0.6	1.1	5.7	11.2	5.5	**24.2**	P	24.2	2032	-	P	29.0	2029
		The investment was descoped to exclude the replacement of one transformer as its priority ranking decreased following an updated assessment.														
T-SR-01.29	Kenora TS	0.0	**0**	0.6	0.7	3.1	7.4	4	**15.8**	P	15.8	2032	-	P	14.4	2031
T-SR-01.30	Mississagi TS	0.0	**0**	0	0	0.6	0.8	3.7	**5.2**	P	18.9	2034	-	P	23.5	2027
		The project was descoped to replace the instrument transformers and switches only due to changes in replacement priority, aligning with updated assessment criteria. The project has been deferred due to portfolio reprioritization.														
T-SR-01.31	Hawthorne TS	0.0	**12.2**	0.2	0.3	2.9	21	25.8	**50.3**	P	62.5	2032	-	P	37.4	2028
		This investment was in a preliminary planning phase when the original forecast for the Plan was established. Since the Plan was prepared, the forecast cost of this investment increased as the estimate matured and scope was added. Specifically, the investment now includes the replacement of end-of-life 115 kV protections and feeders that no longer meet bulk electric system station standards. This investment improves system reliability and mitigates the risk of equipment failure. The investment was deferred due to portfolio reprioritization. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-01.32	Cataraqui TS	0.0	**0**	0.5	0.5	4.5	25	16.2	**46.7**	P	46.7	2032	-	P	38.4	2030
T-SR-01.33	Claireville TS		**0**	0	0	0.3	1	0.9	**2.1**	P	213.7	2035	-	P	102.8	2030
		The project was in a preliminary planning phase when the original forecast for the Plan was determined. The project has since been deferred with only immaterial spend currently expected in the 2028-2032 period. New asset information necessitating scope changes, along with unit cost increases and inflationary pressures contributed to the variance.														
T-SR-01.36	Keith TS: PSR5	0.0	**42.6**	9.6	0.4	0	0	0	**10**	E	52.6	2028	-	P	42.5	2026
T-SR-01.37	Milton SS; GIS	0.0	**11.0**	4.9	4.3	0	0	0	**9.2**	E	20.2	2029	-	P	9.1	2027
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Since the Plan was prepared, the forecast cost of this investment increased as the estimate matured and the execution plan was developed, accounting for outage coordination with other major projects. The execution plan impacted the schedule and increased project complexity relative to the preliminary estimate. The current project cost reflects current construction, commissioning, and indirect cost estimates.														
T-SR-01.38	Hunta SS	1.2	**0.7**	4.8	6.7	1.1	0.1	0	**12.7**	E	14.6	2030	-	P	10.9	2025
T-SR-01.39	Hanmer: Insulator	0.4	**5.6**	8.9	3.3	3.3	0	0	**15.5**	P	21.5	2030	-	P	24.8	2030
T-SR-01.40	Pickering ASS	0.0	**1.2**	2.3	4.4	2.1	0	0	**8.8**	P	10	2030	-	-	-	-
T-SR-01.41	Pickering BSS	0.0	**18.3**	15.6	14.1	19.7	5.6	1.8	**56.7**	P	75.2	2032	-	-	-	-

T-SR-01.42	Chats Falls	0.0	**0**	0.3	0.5	1.2	6.7	4.3	**13**	P	13	2032	-	P	6.2	2029
T-SR-01.43	Hawthorne TS: TS Autotransformer Upgrade	0.0	**0**	2	3	10	20	15	**50**	P	50	2032	-	-	-	-
T-SR-01.44	Hanmer TS	0.0	**0**	0.3	0.7	2.7	15.2	9.9	**28.8**	P	28.8	2032	-	P	24.7	2031
T-SR-01.46	Middleport TS: T3	0.0	**0**	0.3	3.1	6.4	16.4	13.4	**39.6**	P	51.9	2033	-	-	-	-
T-SR-01.47	Marathon TS – T11 & T12	0.0	**0**	0	0	0.5	0.8	5.2	**6.5**	P	39.7	2034	-	-	-	-
T-SR-01.48	Dryden TS	0.0	**0**	0	0	0.5	0.5	4.4	**5.4**	P	45.8	2034	-	P	18.5	2032
T-SR-01.49	Burlington TS	0.0	**0**	0	0	0.6	0.5	5.7	**6.8**	P	59.6	2034	-			
T-SR-01.50	Dymond TS	0.0	**0**	0	0	0.4	0.6	4.7	**5.8**	P	49.7	2034	-	P	17.8	2031
T-SR-01.51	Porcupine TS: Cap Banks	0.0	**0**	0	0	0.5	5.5	5.6	**11.6**	P	36.3	2035	-	-	-	-

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T-SR-02	**TRANSMISSION STATION RENEWAL – AIR BLAST CIRCUIT BREAKERS**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Net Cost	38.1	29.3	17.5	63.3	82.5	230.7

Summary:

This investment involves the replacement of all Air Blast Circuit Breakers (ABCBs) at Hydro One's transmission stations due to the asset's poor condition, obsolescence and poor performance. In some cases, investments may also include replacement of additional kinds of breakers as well as the removal, upgrade or replacement of other station equipment. The primary trigger for the investment is the significant reliability risk and high operation and maintenance costs associated with poor condition ABCBs. The investment is expected to increase reliability performance, reduce operation and maintenance costs, and decrease unplanned outages within major bulk transmission stations.

1.0 OVERVIEW

The Air Blast Circuit Breaker Replacement investment involves the replacement of ABCBs and their auxiliary station equipment that are at a high risk of failure due to their deteriorated condition. All 24 High-Voltage ABCBs that remain in-service are in poor condition and will be replaced under this investment. This investment will address several risks associated with the remaining ABCBs, including unacceptable reliability performance posing risks to continuous operation of bulk electricity system, high operation and maintenance costs and unavailability of spare parts and technical support. ABCBs were originally installed in the 1970s, posing another significant challenge in terms of the high operating costs required to maintain system reliability. The lack of available spare parts due to the obsolescence of the technology further constrains Hydro One's ability to maintain these assets to ensure that the appropriate level of reliability is maintained.

Historically, almost half of Hydro One's ABCBs population were installed at critical transmission network stations that connect major nuclear and hydraulic generation plants and deliver power to major load centers in Ontario. These transmission network stations also connect international power flow to the states of New York and Michigan. Any forced outages at these critical transmission stations due to ABCB failures may adversely impact and/or constrain generation resources and lessen the reliability of bulk power flows to load centres. In the case of nuclear generating plants, a forced outage can cause supply interruptions to the station service transformers and/or the loss of production.

To mitigate provincial power flow interruptions and customers' concerns associated with high-risk reliability performance stemming from deteriorated ABCB assets, Hydro One evaluated several alternatives, as further described below, and concluded that continued targeted replacement of poor condition ABCBs is the most prudent and required alternative. Hydro One has continued to prioritize the replacement of all ABCBs and only 24 High-Voltage ABCB breakers at two stations remain in-service and are to be replaced during the 2028-2032 planning period. The remaining breakers include six at Essa TS, six at Cherrywood TS related to the Pickering Generation Station and another twelve at Cherrywood TS unrelated to Pickering Generation Station. The forecasted expenditures for the investment are estimated to be $230.7M over the 2028-2032 planning period.

The scope, need and outcome for each project are summarized in Appendix A.

2.0 INVESTMENT NEED

ABCBs were developed in the 1950's to solve the technical limitations that oil circuit breakers could not overcome. ABCBs rely on complex mechanical and pneumatic subsystems for proper operation. Between 1950 and 1982, Ontario Hydro (the predecessor of Hydro One) installed 278 High Voltage (HV) (i.e., 115 kV and above) and 10 Medium Voltage (MV) (i.e., 44 kV and below) ABCBs at various transmission stations. Almost half of Hydro One's ABCBs population were originally installed at critical transmission network stations to connect major nuclear and hydraulic generation plants and deliver power to major load centers in Ontario as well as connect international power flow to the states of New York and Michigan.

As of December 2025, 245 HV and 10 MV ABCBs have been replaced and Hydro One expects to replace 9 more prior to 2028. Many of the ABCBs replaced had various control component issues such as air leaks, operating mechanism issues, moisture content problems and auxiliary equipment malfunctions. Hydro One's typical practice is to repair the breakers where issues (e.g., air leaks) have been identified. However, Hydro One's fleet of ABCBs is no longer supported by vendors and as such, it is extremely difficult to obtain technical support and spare parts which are either no longer available or are costly to acquire or fabricate. Replacing the remaining 24 HV ABCBs with standard SF_6 breakers will reduce the maintenance cost for each replaced breaker.

Through asset condition assessment, Hydro One has confirmed that all remaining ABCBs are in poor condition. ABCBs are the poorest performing breaker population in Hydro One's transmission system. Typical ABCB failure modes have included control component issues, air leaks, operating mechanism issues, moisture content problems and auxiliary equipment malfunctions.

For example, over the last five years, the remaining ABCBs at Cherrywood TS have experienced recurring pneumatic system reliability issues, primarily involving air leaks, low-air alarms, control valves, fill valves, pressure switches, and associated air-system components. One problematic breaker has experienced repeated low-air conditions, over-

pressurization events, fill-valve faults, spider valve leakage, and multiple pressure switch recalibrations before receiving a major air-system modification in 2026. Other recurring issues include air leaks in breaker heads and control valves, and general deterioration. Overall, the remaining ABCBs at Cherrywood exhibit an aging pneumatic operating system with repeated maintenance interventions.

Outages associated with both routine and emergency maintenance on ABCBs are longer and more costly compared to newer technology, due to a combination of the unavailability of spare parts due to obsolescence and the lack of technical support to work on the deteriorating population of installed ABCBs. This puts constraints on Hydro One to ensure its transmission system performs in compliance with all regulatory requirements and meets the high expectations of its customers. As such, continued replacement of ABCBs is required.

3.0 INVESTMENT DESCRIPTION

The investment involves a series of individual investments at two transformer stations, as further described in Appendix A below. Each ABCB replacement investment will vary in size and scope and will replace ABCBs and other station assets where condition warrants replacement, as well as address any potential site and property issues, customer issues, safety and/or environmental concerns. Such investments can include the replacement of other breakers, removal of the high-pressure air system, the upgrade of AC and DC systems, protection, control and telecom systems, upgrades to high-risk station ancillary equipment, site or property upgrades, customer triggered upgrades, as well as upgrades driven by safety concerns, environmental compliance and operational issues.

Hydro One has prioritized the replacement of all ABCBs. Cumulatively, this investment targets the replacement of all 24 remaining ABCBs, with replacement equipment to be in-serviced during the 2028-2032 planning period at Essa TS and Cherrywood TS. The remaining breakers include six 500 kV ABCBs at Essa TS, six 230 kV ABCBs at Cherrywood TS related to the Pickering Generation Station and another twelve 230 kV ABCBs at Cherrywood TS unrelated to Pickering Generation Station.

4.0 OUTCOMES

As a result of the investment, Hydro One will improve system reliability by reducing the frequency and duration of outages caused by failed ABCBs. The investment will result in reduced operational risks associated with the operation of poor condition equipment. Hydro One will reduce its operating costs associated with ABCBs and reduce maintenance costs associated with high pressure air systems. The investment will also assist Hydro One in ensuring compliance with the North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and Independent Electricity System Operator (IESO) requirements.

4.1 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	• Improve system reliability by reducing the frequency and duration of the outages due to high risk and obsolete equipment, which are particularly vulnerable to failures during extreme cold weather • Staged approach to minimize customer outages
Operational Effectiveness	• Reduce operational risks associated with the operation of assets in poor condition • Improve reliability to the bulk electric system • Improve operational effectiveness of the station through reconfiguration and standardization of new equipment and design
Public Policy Responsiveness	• Ensure compliance with applicable regulatory and environmental requirements

5.0 EXPENDITURE PLAN

As discussed above, the investment involves the replacement of ABCBs and other station equipment based on deteriorated condition and obsolescence.

Table 2 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period. Appendix B includes individual investment expenditures and variance explanations.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	41.8	30.2	17.9	65.3	85.1	240.3
Less Removals	3.7	0.9	0.4	2.0	2.6	9.5
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**38.1**	**29.3**	**17.5**	**63.3**	**82.5**	**230.7**

The factors influencing the cost of the investment include:

- The circuit breaker voltage level and the number of ABCB replacements – the higher the voltage levels, the higher the cost of equipment needed. Higher voltage levels require additional space requirements due to increased electrical clearances, more structures, etc.
- The station design and configuration, including foundation and structural replacements, and whether the replacement is in-situ or greenfield. Costs are also influenced by safety requirements based on the latest Hydro One standards (i.e., new clearance requirements, Arc Flash requirements, etc.).
- NERC and/or NPCC requirements for physical separation and redundancy.
- Outage availability and reduced contingency concerns. Outage availability is more difficult to achieve at nuclear facilities due to stricter contingency planning (N-2 contingency requirements).

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred option.

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENT

Reactive Component Replacement is a “Do Nothing” alternative and is based on reactive response as the failures occur and replacing ABCB sub-components as and where needed. Hydro One rejected the “Do Nothing” alternative for the following reasons:

1. Reactive management of ABCBs at critical transformer stations would decrease reliability of the transmission network and generation station connections by

[1] Figures presented in the tables may not sum to the totals shown due to rounding.

increasing outage durations to facilitate emergency repairs. Increased frequency and duration of outages could impact connected customers, increase OM&A cost due to unplanned corrective work. Further the air system must be maintained until all ABCBs are replaced.

2. Reactive replacement would be limited to addressing failed sub-components and would not address other deteriorated sub-components with a similar risk of failing. Reactive repairs would result in increased OM&A costs correlated with the frequency of outages.
3. Should a major failure occur, like-for-like replacement of the entire breaker would not be possible in many cases due to the unavailability of spare units. Replacement with a modern SF_6 circuit breaker, requiring additional time for design, construction, and commissioning, would prolong the outage thereby impacting system reliability and customer satisfaction if done on a reactive basis.

ALTERNATIVE 2: SWITCHYARD REBUILD

A switchyard rebuild comprises rebuilding the entire ABCB switchyard in a new location (greenfield) using modern SF_6 breakers, instead of replacing only the assets in need of replacement by installing them in new locations within the existing station property (brownfield). This alternative is considered when operational constraints, space and execution timelines prevent an in-situ option to be deployed. Other challenges include expansion of the existing station property, real estate acquisition, and potential reconfiguration of the existing switchyard connections. Each station is analyzed based on its specific needs to determine the best alternative.

Due to the significant cost difference, Hydro One's typical direction is to carry out an in-situ replacement unless in-situ replacement is not feasible.

ALTERNATIVE 3: PLANNED IN-SITU REPLACEMENTS (RECOMMENDED)

Planned in-situ replacement is the recommended approach. This alternative is based on replacing ABCBs and auxiliary systems within the same station footprint using modern SF_6 breakers. SF_6 is the predominant insulating medium in the industry; possessing the highest dielectric strength of any known gas, excellent arc extinguishing and quenching

capabilities, thermal stability, and superior heat transfer properties. This alternative has been selected as the recommended alternative for the following reasons:

1. In-situ replacement resolves all of the challenges facing the ABCB fleet described above by increasing system reliability in the most cost-effective manner. It aligns with the needs of Hydro One's customers and Hydro One's ABCB strategy to resolve current ABCB performance challenges.
2. The recommended alternative, unlike the reactive alternative, proactively addresses and paces replacements without jeopardizing system reliability and customer supply points. Unlike Alternative 2, the recommended alternative results in a more cost-effective solution since most real estate and station reconfiguration challenges are avoided.

7.0 EXECUTION RISK AND MITIGATION

As described in TSP Section 2.11, Hydro One follows a Transmission Capital Project Delivery Model, throughout which project risks are identified and mitigation plans are implemented. Risks that can impact the completion of ABCB replacement projects include:

- Outage constraints:
  - Planned outages are required to replace assets. Outages may include individual assets, sections of a station, or the entire station for construction and commissioning staff to perform replacement of assets.
- Outages must be planned and coordinated to minimize the impact to customers.
- Resource constraints:
  - All transmission station renewal projects use the same teams of management and engineering resources.
  - Projects in the same geographical location use the same teams of construction and commissioning resources.
- Construction execution challenges:
  - Existing station equipment may require retrofits to accommodate new assets as station design and equipment standards have evolved.
  - Significant design and construction is required to replace assets if assets cannot be replaced in the same physical location due to space constraints, outages or safety consideration.

- Customer coordination:
  - Hydro One puts best efforts into coordinating with customers.
- Real estate requirements:
  - Station expansion and new land may be required when assets cannot be replaced in the same physical location.

APPENDIX A – DESCRIPTION OF FORECAST INVESTMENTS

This Appendix describes each material investment and forecast capital expenditures for the 2028-2032 planning period.

ISD Ref.	Station Name	Scope, Need and Outcome	Forecast Replacement Units			28-32 Total	Project Total
			Trfr	Brkr	Prot		
T-SR-02.10	Essa TS	ABCB breakers at Essa TS are over 50 years old and based on the asset condition assessment are determined to be in poor condition. Consistent with the ABCB breaker replacement strategy, this investment will replace six 500 kV ABCBs and associated 500KV switches and other poor condition and/or obsolete assets, as well as protection and control system upgrades. Replacing these units will maintain reliability of power delivery to high voltage NERC and NPCC Bulk Electric System.	0	6	32	46.1	107.2
T-SR-02.11	Cherrywood TS	230 kV ABCB breakers at Cherrywood TS are over 50 years old and based on the asset condition assessment are determined to be in poor condition. Consistent with the ABCB breaker replacement strategy, this investment will replace six 230 kV ABCBs, two 230kV oil breakers, and associated switches and other poor condition and/or obsolete assets, as well as protection and control system upgrades. Replacing the remaining breakers will maintain reliability of power delivery to high voltage network. The scope of work in this investment is coordinated with OPG's planned refurbishment of the Pickering B Nuclear Generation Station.	0	8	12	30.6	42.3
T-SR-02.12	Cherrywood TS	230 kV ABCB breakers at Cherrywood TS are over 50 years old and based on the asset condition assessment are determined to be in poor condition.	0	26	32	153.3	167.3

		Consistent with the ABCB breaker replacement strategy, this investment will replace the remaining twelve 230 kV ABCBs, twelve 230 kV oil breakers, two SF_6 circuit breakers, associated switches and other poor condition and/or obsolete assets, as well as protection and control system upgrades. Replacing the remaining breakers will maintain reliability of power delivery to high voltage network. The scope of work in this investment covers the asset replacements at Cherrywood TS which are not associated with the Pickering Generation Station and have been separated in order maintain network transfer capability during the Pickering B refurbishment.					
	Total		**0**	**40**	**76**	**-**	**-**

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

The investments proposed in this ISD are complex and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.11. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project, the in-service year and the project total estimates for the 2023-2027 and 2028-2032 rate periods. Project maturity is defined by the following project phases:

- Execution (E), which reflects fully approved project work;
- Planning and Definition (P), which reflects non-execution work, regardless of level of upfront development; and
- Complete (C), which reflects that the project has been placed in service.

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in the table below in reference to project total variances and overall project schedule variances.

1

Table B1 - Hydro One – Detailed Material Investment Costs ($M)

ISD Ref.	Project Name	Actual Pre 2023	Net Capital Investment ($ Millions)							Project Forecast			Prior Project Forecast[2]			
			Act/Fcst 23-27[3]	2028	2029	2030	2031	2032	28-32 Total	Project Phase	Proj. Total	In Service Year	ISD Ref.	Prior Project Phase	Prior Proj. Total	Prior In Service Year
	Beck 2 TS	109.1	18	0.0	0.0	0.0	0.0	0.0	0.0	C	127.1	2024	T-SR-02.02	E	122.2	2023
		The variance is attributable to outage delays and complications impacting the schedule and therefore effort, leading to higher construction and commissioning costs.														
	Bruce B SS	165.8	11.6	0.0	0.0	0.0	0.0	0.0	0.0	C	177.4	2022	T-SR-02.03	E	182.3	2024
		The variance is attributable to effective project management and contract management.														
	Middleport TS	114.1	52.2	0.0	0.0	0.0	0.0	0.0	0.0	C	166.3	2025	T-SR-02.05	E	178.1	2025
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
	Lennox TS	112.8	35.3	0.0	0.0	0.0	0.0	0.0	0.0	C	148.1	2025	T-SR-02.07	E	143.2	2026
		The increased cost of this project relative to the prior estimate is primarily due to cost escalation. Cost escalation was partially offset through optimizing and execution of the outage staging plan, resulting in overall project cost savings of approximately $6M.														
	Beck 1 SS	23.9	15.8	0.0	0.0	0.0	0.0	0.0	0.0	C	39.7	2026	T-SR-02.08	E	54.2	2026
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
	Bruce A TS	12.7	473.8	0.7	0.0	0.0	0.0	0.0	0.7	E	487.3	2027	T-SR-02.09	P	316.2	2027
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-02.10	Essa TS	1.8	59.2	26.1	19.3	0.7	0.0	0.0	46.1	E	107.2	2030	T-SR-02.10	P	75.9	2028
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-02.11	Cherrywood TS	0.0	11.8	11.0	9.3	7.6	2.6	0.0	30.6	P	42.3	2031	T-SR-02.11	P	129.7	2030
		The project was in a preliminary planning phase when the original forecast for the 2023-2027 period was established. The variance is attributable to a refinement in planning and execution strategy resulting from OPG's announced refurbishment of Pickering B Nuclear Generation Station. The scope of the project has been reduced to leverage station and circuit outages in coordination with OPG while maintaining transfer capability through Cherrywood TS during the refurbishment. Project T-SR-02.12 has been developed to address the remaining ABCBs previously scoped within this project.														
T-SR-02.12	Cherrywood TS	0.0	0.0	0.3	0.6	9.2	60.7	82.5	153.3	P	167.3	2033	-	-	-	-

2

[2] "Prior Project Forecast" refers to the forecast project total and in-service date when Hydro One revised the capital 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.

Witness: Mark Brodie

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T-SR-03	**TRANSMISSION STATION RENEWAL – CONNECTION STATIONS**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	-	102.3	144.5	360.1	688.7	763.6	2,059.2
HOSSM[1]	15.5	28.8	14.3	15.2	15.6	6.6	80.5

Summary:

This investment involves the replacement of critical transmission station assets at connection stations that have deteriorated to poor condition, thereby posing reliability, safety and environmental risks. The primary triggers of the investment are high risk of asset failures, deteriorated condition and need to maintain transmission system and customer supply reliability. The investment is expected to mitigate the risk of reduced supply reliability and customer outages due to equipment failures.

[1] See Appendix C for a description of HOSSM's station renewal investments.

1.0 OVERVIEW

Connection stations are transmission stations serving Local Distribution Companies (LDCs) and large industrial customers. The LDCs, in turn, serve Ontario's residential, commercial, institutional and small industrial end-users. Connection stations are connected to the network stations through 230kV and 115kV high-voltage lines and serve customers at distribution system voltage via 44kV, 27.6kV and 13.8kV feeders. Connection station assets include the following critical transmission assets: (i) step-down power transformers that convert higher transmission level voltages to lower distribution level voltages, (ii) circuit breakers and protection systems that protect transmission station assets, customer equipment, and reduce outages, (iii) switchgear that facilitates the distribution of power to the downstream distribution network. These critical transmission station assets degrade over time.

The Transmission Station Renewal – Connection Stations investment manages asset-failure related risks to stations performance and operational effectiveness through the replacement of key station assets that have been verified to be in poor condition. The investment involves a series of individual projects and includes the replacement of multiple assets within a particular station. The scope of each project includes renewal of poor condition transformers, breakers, switchgear, and protection and control systems. Investments may also include other station assets, such as instrument transformers, disconnect switches and other ancillary equipment, as and where required.

Hydro One's connection stations provide the electrical energy necessary to power the provincial economy and meet society's daily needs. Hydro One actively works with LDCs and large industrial customers to understand their needs and preferences. As discussed below in Section 3.0, customer engagement expressed strong support for the replacement of aging and deteriorating transmission station assets in order to maintain the overall health of the transmission system.

Where multiple critical assets require replacement and station-wide coordination is needed, Hydro One may employ an "integrated station approach" to renew major power system equipment through a single project in coordination with broader regional or bulk system needs. Ancillary equipment in need of replacement will also be included. This

approach maximizes outage efficiency, reduces customer disruptions, and provides opportunities for station modernization, reliability improvements, and configuration enhancements.

Given the combination of regulatory requirements and the critical role of electricity in Ontario's homes, businesses, and institutions, Hydro One cannot run its transmission assets to failure. Hydro One's priority is to maintain the availability and reliable operation of its transmission facilities. Accordingly, the proposed renewal spending is anchored on replacing assets based on their condition. To optimize the amount of risk mitigated in the pacing of investments, Hydro One prioritizes investments based on total risk mitigation, risk spend efficiency, and contribution to desired outcomes, as detailed in SPF Section 1.7.

2.0 INVESTMENT NEED

The investment focuses on the replacement of poor condition transmission station assets that facilitate power transformation from a high transmission voltage to a lower distribution voltage. Operating assets that are in poor condition pose an increased risk of failure or of not operating as intended. Transformers may catch fire and result in extensive damage and oil spills both on and off-site into the neighbouring environment. Breakers may fail to operate (open) when needed, as they are intended to, or they may experience insulation failure leading to internal arcing during operation, causing irreparable damage. Failures to critical assets may result in damage to connected equipment, impacts to system stability, interruptions to customer delivery points with significant durations, employee and public safety risks, and environmental impacts.

Failures of critical assets at a connection station may have serious consequences, as they may partially or entirely interrupt power flow to load customers and constrain embedded generation on the distribution network connected to the station. Under normal operating conditions, a failure of a single asset at a connection station will usually not result in an extended load interruption due to the standard design redundancy of Hydro One's transmission connection stations. However, even where customers do not experience an immediate interruption, the system must be restored to full redundancy as soon as possible to mitigate additional risks and prevent major load loss consequences.

As discussed in TSP Section 2.2.2, forced outages can also decrease redundancy, increase wear and tear on other assets, and cause the cancellation or rescheduling of planned outages for maintenance, repair, and replacement work. Furthermore, at many connection stations, a significant proportion of station load may be 'stranded', meaning the load cannot be immediately transferred to another station or transferred within the distribution system. A failure at a vulnerable station with stranded load would result in extended power outages until an emergency measure is implemented. Such an outcome would be inconsistent with the level of service expected by generation customers, industrial customers and Local Distribution Companies. Leaving poor condition transmission station assets in-service also increases the risk of catastrophic failures, which poses a safety risk for Hydro One staff and the public.

Major transformer failures have been key drivers of prolonged outage durations. For example, the 2018 failure of Finch TS T2 (a 230–28kV step-down transformer) resulted in an explosion, fire, and oil leakage, requiring a full replacement that took one year due to site cleanup, removal, and installation activities. In 2022, Hanover T2 (a 115–44kV step-down transformer) experienced an under load tap changer (ULTC) burnout and irreparable oil leakage on a significantly aged unit, resulting in a replacement process lasting more than one year, including removal, installation at a new site, and mobile transformer unit (MTU) mobilization. Each time a transformer fails, and redundancy is lost for months, the system remains exposed and any subsequent failure of the companion transformer can lead to severe consequences for load and customers. Therefore, minimizing unplanned transformer failures is critically important to maintaining system reliability and customer service.

The condition of transformers and breakers, and the age of protection and control systems are the leading indicators of the assets' performance that may eventually lead to catastrophic events, such as those described above. Given the criticality of transmission assets, Hydro One does not run them to failure. Asset deterioration is not reversible and cannot be stopped. Hydro One has a significant amount of assets that have been verified to be in poor condition. In addition, there is a large population of transmission assets that are in fair condition, meaning that there is some form of deterioration. This population of assets will eventually start migrating to the poor condition category as the asset continues

to deteriorate over time. Key station assets demographics and condition are further described below.

TRANSFORMER CONDITION – CONNECTION STATIONS

As discussed in TSP Section 2.2.2.1, transformer condition is a leading indicator of performance and a main driver for replacement. Transformer condition can be impacted by several factors including loading history (i.e., the amount of power it must transform), age, weather exposure, and operating conditions. If a transformer exhibiting deterioration is highly loaded, it is likely to deteriorate faster than if it carries a lower load.

A transformer's load profile can depend on the station's design and the load the transformer is expected to carry during normal and temporary conditions. In a station with two transformers, one of the transformers may be required to temporarily carry a higher load as a result of an extended (planned or forced) outage of the companion transformer. Under this scenario, the remaining in-service transformer (which likely has characteristics that are similar to the companion unit, and has been subjected to similar environmental conditions and loading) would be required to bear the full load of both transformers and therefore experience further condition deterioration as a result.

The overall condition of a transmission transformer is evaluated based on a detailed condition assessment using the most recent condition data as well as historical data relating to four main indicators: (i) insulation deterioration within the main tank, (ii) oil leaks, (iii) cooling system failure, and (iv) tap changer malfunction.

Operating a large number of transformers in poor condition increases system reliability risk because these assets have a higher probability of failure. An assessment of the connection station transformer fleet's condition shows that approximately 136 units, representing 23% of transformers within connection stations, are rated as being in poor condition. More information on asset demographics, condition and other factors can be found in TSP Section 2.2.2.1.

BREAKER CONDITION – CONNECTION STATIONS

Similar to transformers, breaker condition is a leading indicator of expected performance. Poor condition breakers can ultimately result in outages and severely impact system stability, the operations of other connected equipment, and employee and public safety. Asset condition is determined through preventive maintenance including diagnostic testing and inspections and is one of the major drivers for breaker replacement as part of the investment.

As discussed in TSP Section 2.2.2.2, circuit breakers use different interrupting mediums such as oil, air, and SF_6 gas to extinguish electric arcs during operation. For air and SF_6 breakers, these gases must be kept at high pressure to work effectively. As breakers age, their O-rings and gaskets deteriorate, leading to SF_6 leaks. When this happens, the internal pressure drops and moisture can enter the equipment. Both reduced pressure and moisture lower the breaker's dielectric strength, weakening its ability to quench arcs. This increases the risk of internal flashover, which in severe cases can result in an explosive breaker failure.

In addition to condition, the presence of obsolescence can necessitate the replacement of assets that might otherwise remain operational. Obsolescence creates reliability and maintainability risks, such as limited availability of spare parts, discontinued manufacturer support, and the inability to safely or effectively perform modern testing, diagnostics, or repairs. These risks can materially increase the likelihood and consequence of in-service failures over time.

Similar to transformers, operating a large number of circuit breakers in poor condition increases system reliability risk, as this equipment tends to have poorer performance and a higher probability of failure. The assessment of circuit breaker condition at connection stations shows that approximately 329 breakers, representing 9% of breakers located within connection stations, are rated as being in poor condition. More information on asset demographics, condition and other factors can be found in TSP Section 2.2.2.2.

Hydro One has 2,061 breakers, or 44% of the overall fleet, that are considered obsolete, with approximately 545 breakers, or 11%, no longer supported by vendors and for which aftermarket parts are not available or are costly to acquire or fabricate. Where parts are difficult to procure, specific units are replaced so the decommissioned units can serve as strategic spares for the remaining in-service fleet, but that is currently not feasible for approximately 11% of the overall fleet.

Hydro One's approach with respect to the replacement of breakers is a targeted, risk-based approach that prioritizes the renewal of breakers most likely to impact safety, reliability, or maintainability. Breakers are selected for replacement based on deteriorated condition, obsolescence, vendor support, environmental impact, system criticality, and overall safety risk.

Table 1 below provides a summary of reasons and need for asset replacement based on the breaker type.

Table 1 - Reasons for Breaker Replacement by Breaker Type

Type of Breaker	Reason for Replacement
Oil Breaker	• Condition and reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • Non-compliance with current system operating ratings • Current rating changes
Air Blast Breakers	• Significant negative impact on outage frequency • Deteriorating condition and performance • Obsolescence due to lack of vendor support and unavailability of maintenance parts • Elimination of high maintenance costs
SF_6 Breakers	• Condition and reliability concerns • First generation SF_6 breakers • Obsolescence due to lack of vendor support and unavailability of maintenance parts • SF_6 emissions • Current Rating changes
GIS Breakers	• Reliability concerns • Obsolescence due to lack of vendor support and unavailability of maintenance parts • SF_6 emissions
Metalclad	• Arc flash hazards • Obsolescence due to lack of vendor support and unavailability of maintenance parts
Vacuum	• Obsolescence due to lack of vendor support and unavailability of maintenance parts

A major driver for replacement is ensuring breakers have adequate short-circuit interrupting capability. As new customer connections, system upgrades, and network reinforcements alter fault levels, Hydro One conducts project-specific short-circuit studies as part of the IESO Connection Assessment and Approval process. Where short circuit level ratings are exceeded, breakers need to be upgraded to a higher short circuit rating, since operating beyond the nameplate rating can cause the breaker to fail.

Overall, this strategy ensures Hydro One systematically transitions high-risk and obsolete breaker fleets to modern, reliable, and supportable technologies while aligning capital investments with system needs and maximizing risk reduction.

PROTECTION EQUIPMENT DEMOGRAPHICS – CONNECTION STATIONS

In contrast to other major power system assets like transformers and circuit breakers (which are replaced based on the condition of the equipment), the ESL of protection devices plays an important role in the assessment for replacements of protection relays. This is because assessment for physical breakdown or loss of strength over time is not feasible or relevant given the make-up of these electronic or solid-state devices. As such, to prevent the potentially significant reliability and safety impact of a sudden failure, ESL is necessarily a key trigger for further evaluation to confirm replacement needs.

As explained in TSP Section 2.2.2.3, there are 3,329 (approximately 26% of the total population) Hydro One protection systems operating beyond ESL. Such devices are subject to an elevated risk of failure, while also having very limited or no support from vendors in terms of replacement units, spare parts, and engineering and firmware support. As such, reactive repairs may involve extended durations as re-engineering and construction work will be required to install new devices based on different technology. These risks could lead to prolonged outages for customers. More information on asset demographics, condition and other factors can be found in TSP Section 2.2.2.3.

3.0 INVESTMENT DESCRIPTION

As discussed above, this investment focuses on the replacement of multiple connection station assets that facilitate power transformation from a high transmission voltage to a lower distribution voltage. This integrated station approach focuses on a particular station where multiple key station assets require replacement, as driven by their condition, and investments may be accompanied by some level of electrical re-configuration to address operating concerns and customer preferences or to standardize the installed equipment.

As described in SPF Section 1.7 and TSP Section 2.7, Hydro One performs an asset risk assessment. Where the assessment identifies multiple assets in poor condition at a station, the station may be identified as a candidate for investment. All candidate investments undergo a risk-based prioritization assessment to determine whether they should be included in the Investment Plan. As a result of the investment planning process, over the 2028-2032 period, the investment includes 66 material investments at connection stations and addresses the replacement of 87 transformers (40 to be in-serviced during the 2028-

2032 period), 300 breakers (94 to be in-serviced during the 2028-2032 period), and 929 protection systems (471 to be in-serviced during the 2028-2032 period). While Hydro One has a significant number of transmission station assets that are in poor condition, this investment primarily addresses critical and pressing issues that require attention. Hydro One will also address other minor station assets (e.g., ancillary equipment) where condition warrants replacement, as well as any potential site and property issues, customer issues, safety and/or environmental concerns. A detailed list of assets planned for replacement is presented in Appendix A below.

Hydro One also performs functional reconfiguration and station right-sizing analyses to ensure alignment with load forecasts and applicable industry and regulatory standards. Functional reconfiguration is the reconnection of power system elements (e.g., breakers, transformers) within a transmission station into a new electrical configuration. This can either better facilitate a customer connection, a connection to the bulk power system or help eliminate operational restrictions or limitations which can aid in the transfer or restoration of power during a faulted condition where an element is removed from service. Functional configuration and station right-sizing, where possible, allows Hydro One to replace two smaller rated transformers with a single standardized transformer that delivers the same capacity. This helps Hydro One maintain a standardized catalogue of power equipment to minimize the various types of spare equipment required.

Hydro One customers broadly support the replacement of deteriorating transmission stations assets. As described in SPF Sections 1.6 and 1.7, and TSP Section 2.7, Hydro One actively works with its customers to capture their needs and preferences and implement the necessary changes to Hydro One designs, where feasible, to meet those needs. In conjunction with its planning process, Hydro One carried out a comprehensive, two-phase customer engagement to inform the development of investment strategies and candidate investments, including the pacing of transmission station and lines reinvestment. Across all customer types, customers chose the draft plan as their preferred option for replacing transmission station assets in poor condition. In regard to replacing aging transmission stations, Hydro One’s customers expressed support for the replacement of aging and deteriorating transmission station assets to maintain the overall health of the system. Hydro One’s investment plan addresses aging and deteriorated assets and has

been optimized to sustain the current performance of the transmission system, matching customers' expectations.

4.0 OUTCOMES

As a result of the investment, Hydro One will reduce operational risks associated with operating equipment in poor condition; ensure compliance with the Ministry of Environment, Conservation and Parks in regard to oil spills; maintain long-term reliability of the connection stations; address operational concerns through reconfiguration; and reduce constraints on generation resources.

4.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 2 - Outcomes Summary

Customer Focus	• Maintain reliable power delivery at connection stations and reduce the risk of customer outages arising from equipment failure.
Operational Effectiveness	• Improve the operational effectiveness of connection stations through reconfiguration and standardization of new equipment and design, while reducing operational risks associated with equipment in poor condition.
Public Policy Responsiveness	• Support compliance with applicable regulatory requirements.

5.0 EXPENDITURE PLAN

As discussed above, the investment is needed to replace various connection station assets that are in poor condition, which may lead to unexpected failures. Hydro One planned the investment to achieve completion as effectively and efficiently as possible.

Table 3 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 rate period.

Table 3 - Hydro One - Investment Expenditures[2,3]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	117.3	160.5	377.8	711.3	790.9	2,157.8
Less Removals	4.1	3.5	10.4	20.4	22.8	61.2
Less Capital Contributions	11.0	12.5	7.2	2.3	4.4	37.5
Net Capital Expenditures	**102.3**	**144.5**	**360.1**	**688.7**	**763.6**	**2,059.2**

Hydro One forecasts total capital expenditures of $2,059.2M over the 2028-2032 period, $628.4M more than the $1,430.8M forecast for the 2023-2027 period. The increase is primarily attributable to the nature and size of the projects being undertaken and the composition and scope of the planned project portfolio. It does not reflect a single large material project, but rather the cumulative impact of multiple system investments at various stations reaching execution and commissioning stages within the same period.

The trend in net capital expenditures includes the impact of the inflationary pressures experienced by Hydro One during the 2023-2027 period relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historical material cost escalation trends are described in SPF Section 1.8.3, including the average 115% increase in the cost of power transformers since 2020.

Many of these investments are expected to commence in the years immediately preceding or at the beginning of the application period, with the majority of construction, procurement, and commissioning activities occurring later in the forecast period. As investments advance from planning and design into execution phases, capital spending increases, resulting in higher expenditures toward the end of the planning horizon.

[2] Figures presented in the tables may not sum to the totals shown due to rounding.
[3] Forecast net capital expenditures for the 2028-2032 period include $120.3M of immaterial projects.

The factors influencing the cost of the investment include:

- The number and type of assets being replaced, including transformers, breakers, protection systems, and ancillary equipment. Higher voltage transformers, breakers and ancillary equipment are more costly from a material perspective as is the overall installed cost due to required clearances for high voltage equipment.
- The applicability of Ministry of the Environment, Conservation and Parks (MECP), requirements. Where environmental work, such as spill containment or oil-water separators, is required, additional costs may be incurred to meet these requirements.
- The complexity of project staging and outages required to facilitate work. Greater project complexity, including a higher number of interconnections and required outages, increases project costs.
- Whether the project involves a greenfield replacement or in-situ replacement requiring complex contingency planning. Where sufficient space is available within or near the existing station, a greenfield solution may be less costly because it can be constructed with minimal interference to daily operations. In situ replacement is generally more difficult, from both engineering design and construction perspectives as other equipment will need to be removed from service to facilitate construction and ensure safety and appropriate clearances. This increases the time required for construction and can impact customers as they will be supplied from only a single supply during these times.
- The location of the station, including whether it is in an isolated rural area or congested urban area. Work at a congested urban station generally increases costs and extends construction time because of the clearances required to perform the work safely.

6.0 ALTERNATIVES CONSIDERED

Hydro One considered the following alternatives before selecting the preferred option.

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENT

Reactive component replacement involves waiting for deteriorated condition transformers, breakers, or ancillary equipment to fail and replace components on a reactive basis. Hydro One does not run transmission assets to failure given their criticality to the integrity of the transmission system and the significant reliability, safety and environmental impact associated with their failures. This alternative is more costly not only for Hydro One but also for impacted customers. Hydro One has rejected this alternative for the following reasons:

- Assets in deteriorated condition will continue to deteriorate and decline, thereby increasing the likelihood of unexpected failures. When a critical asset fails, redundancy is lost for several months. In the case where a subsequent failure of a companion unit occurs, the consequences could be significant to the transmission system. Such a failure would be prolonged and result in extended equipment and customer outages which will subsequently negatively affect the Transmission System Average Interruption Duration Index (SAIDI) and Transmission System Average Interruption Frequency Index (SAIFI) performance.
- At the majority of connection stations, a significant proportion of station load may be “stranded”, meaning the load cannot be immediately transferred to another station or transferred within the distribution system. A failure at a vulnerable station with stranded load would result in extended power outages until an emergency measure is implemented.
- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would result in constant reprioritization of planned work and inefficient redeployment of resources.

- This alternative limits the ability to account for future requirements and has a high risk of re-work and future additional costs.
- This strategy is likely to increase operating and maintenance costs, decrease equipment performance and may impact the safety of personnel on site.

ALTERNATIVE 2: PLANNED REPLACEMENT OF STATION ASSETS (RECOMMENDED)

Planned replacement of station assets is the preferred option for this investment.

Unlike reactive replacement following asset failure, the planned replacement of station assets allows Hydro One to address identified asset risks before failures occur. This approach reduces the reliability, safety, environmental and operational risks associated with continuing to operate deteriorated transmission station assets in service or relying on reactive replacement.

During the development of a station renewal investment, Hydro One assesses the condition and replacement needs of station assets and identifies the scope required to address the risks associated with assets in poor condition. Planned renewal also provides an opportunity to assess operational improvements and station right-sizing requirements, which may include changes to station configuration, supply voltage, transformer arrangements or equipment standardization to support customer needs and operational requirements.

This alternative is recommended because it addresses identified asset risks before failure while allowing Hydro One to incorporate asset condition information, customer requirements and operational considerations into the investment. Relative to reactive replacement, it provides a more effective approach to maintaining the reliability, safety and long-term performance of Hydro One transmission stations.

7.0 EXECUTION RISK AND MITIGATION

As described in TSP Section 2.11, Hydro One follows a Transmission Capital Project Delivery Model, throughout which project risks are identified and mitigation plans are

implemented. Risks that can impact the completion of transmission station renewal projects at connection stations include:

- Outage constraints: Planned outages are required to replace assets and may involve individual assets, sections of a station, or the entire station. Hydro One plans and coordinates outages to minimize impacts on customers while providing construction and commissioning staff with the access required to complete the work.
- Resource constraints: Projects in the same geographical location may require the same construction and commissioning resources. Hydro One coordinates project schedules and resource requirements to manage competing demands for these resources.
- Construction execution challenges: Existing station equipment may require retrofits to accommodate new assets because station designs and equipment standards have evolved. Significant design and construction may also be required where assets cannot be replaced in the same physical location due to space constraints, outage requirements or safety considerations.
- Customer coordination: Hydro One coordinates with customers to manage required outages and minimize customer impacts.
- Real estate requirements: Station expansion and new land may be required when assets cannot be replaced in the same physical location.
- Procurement challenges: Equipment procurement lead times can be long. Hydro One engages vendors at appropriate times in the planning process to ensure sufficient lead time to obtain major equipment.

APPENDIX A – DESCRIPTION OF FORECAST INVESTMENTS

This Appendix describes each material investment and forecast capital expenditures for the 2028-2032 period.

ISD Ref.	Station Name/Circuit	Scope, Need and Outcome	Trfr	Brkr	Prot	Total 28-32	Project Total
T-SR-03.018	Murray TS	This investment involves the replacement of power transformers and metalclad switchgear at Murray TS. This investment is needed to address equipment that is in poor condition and at end of life. This investment is expected to maintain reliability to the local area customers and mitigate the risk of outages and supply interruptions due to asset failure.	2	9	21	57.8	61.0
T-SR-03.024	Port Hope TS	This investment involves the replacement of transformers, circuit breakers and other end of life assets. This investment is needed to address the poor condition of the transformers, which have shown degraded condition, including leaking oil and tap-changer issues, and obsolete circuit breakers. The investment is expected to prevent equipment failure, reduce transformer losses, and maintain reliability to Hydro One Distribution customers.	2	9		32.3	40.5
T-SR-03.025	Manby TS	This investment involves the replacement of 230/28kV transformers at Manby TS. This investment is needed to address equipment that is in poor condition and at end of life. The transformers are non-standard 56/93MVA units and will be replaced with standard 50/83MVA capacity units. The investment is expected to maintain reliability to local customers, mitigate the risk of outages and supply interruptions due to asset failure, and reduce transformer losses.	2	11	9	60.0	81.7
T-SR-03.028	Wallace TS	This investment involves the replacement of transformers, oil circuit breakers, and protection and control equipment. This investment is needed to address the poor condition of the transformers, poor condition and obsolete oil circuit breakers, and obsolete protection and control equipment. The investment is expected to maintain reliability of supply to Hydro One Distribution customers in eastern Ontario, decrease the risk of equipment failure, and transformer losses.	2	2	7	28.0	28.0

T-SR-03.029	Bermondsey TS	This investment involved the replacement of power transformers. Both units are in poor condition. T3 is a 230/28-28kV 84/140MVA non-standard unit and T4 is a 230/28-28kV 75/125MVA unit. Both transformers will be replaced with standard 75/125MVA capacity units. The investment is expected to maintain reliability to local customers, mitigate the risk of outages and supply interruptions due to asset failure, and reduce transformer losses.	2		26	43.0	48.7
T-SR-03.034	Midhurst TS	This investment involves the replacement of a 230/44kV stepdown transformer, a 44kV breaker, and protection and control equipment. This investment is needed to address equipment that is in poor condition and at end of life. The investment is expected to maintain existing system reliability and load serving capability of the system and is not meant for system capacity increase purposes. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	1		5	16.6	17.0
T-SR-03.038	Manby TS	This investment involves the replacement of the low voltage switchyard and components including 28kV breakers, switches, and protection & control at Manby TS. This investment is needed to address equipment that is in poor condition and at end of life. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure		12	15	5.9	41.7
T-SR-03.040	Duplex TS	This investment involves the replacement of step-down transformers, infrastructure including spill containments, and protection and control equipment. This investment is needed to address the poor condition of the T1 & T2 transformers. This investment is also needed to eliminate PCB contaminated equipment in the station in order to comply with environmental regulations. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, mitigate the risk of outages and supply interruptions due to asset failure, and reduce transformer losses.	4		12	52.2	89.1
T-SR-03.043	Nebo TS	This investment involves the replacement of transformers, associated switches, spill containment facilities, and protection equipment. This investment is needed to address equipment that is in poor condition and at end of life. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure.	2		7	36.6	36.6

T-SR-03.046	Birmingham TS	This investment involves the replacement of a 115/ 13.8kV transformer, low voltage switchgear and two station service transformers. This investment is needed to address replacement of equipment in poor condition. This station supplies an industrial customer with very large motors and highly sensitive to any supply reliability. This investment also addresses a problematic 115kV line entrance to be reconfigured required for the maintenance purposes. The investment is expected to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.	1	22	28	36.1	75.6
T-SR-03.048	Cherrywood TS	This investment involves the replacement of 44kV oil-filled circuit breakers and associated disconnect switches and protection and control equipment at Cherrywood DESN TS. As a result of final plan for Fairpoint DS (Elexicon Energy Inc. distribution station located within Cherrywood TS), additional reconfiguration in 44kV switchyard may be required. This investment is needed to address equipment that is obsolete and at end of life. The "right sizing" option was considered and evaluated in the GTA East Regional Infrastructure Planning report published in February 2020 for these end of life asset and it was recommended to replace these asset for like for like with current standard equipment. This investment is expected to mitigate risk of equipment failure and maintain supply reliability to Elexicon Energy Inc and Hydro One Distribution customers in the Pickering area.		13	24	41.9	41.9
T-SR-03.049	Gage TS	This investment involves the refurbishment of the T8/T9 DESN at Gage TS. This includes replacement of both transformers and switchgear. This investment is needed to address equipment that is in poor condition, obsolete and at end of life. This investment is expected to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.	2	17	22	49.5	76.5
T-SR-03.050	Woodbridge TS	This investment involves the replacement of a step-down transformer, station infrastructure including spill containment. This investment is needed to address the poor condition T5 transformer. This investment is expected to maintain long-term supply reliability to Alectra and Hydro One Distribution customers in the north GTA, mitigate the risk of outages and supply interruptions due to asset failure, and reduce transformer losses.	1			36.4	38.1

T-SR-03.051	Fairchild TS	This investment involves the replacement of the power transformers, protection & control systems, plus the renewal and upgrade of general station infrastructure including fire walls, spill containment & drainage systems, and noise abatement walls. This investment is needed to address the power transformers and station infrastructure in poor condition, and the obsolete protection & control systems. This investment is expected to maintain long-term supply reliability to Toronto Hydro and Alectra Utilities customers, mitigate the risk of outages and supply interruptions due to asset failure, and reduce transformer losses.	3		34	36.5	65.3
T-SR-03.052	Cedar TS	This investment involves the replacement of 115-13.8kV transformers, 115kV switches, associated switchgear, and protection and control equipment. This investment is needed to address the deteriorating transformers as indicated by recent condition assessments, oil leaks and cooling system issues; and obsolescence of protection equipment. The investment is expected to decrease risk of equipment failure and maintain supply reliability to Alectra Utilities customers.	2		43	41.8	41.8
T-SR-03.054	Waubaushene TS	This investment involves the replacement of 230/44kV stepdown transformers and protection and control equipment. This investment is needed to address equipment that is in poor condition and at end of life. The investment is expected to maintain existing system reliability and load serving capability of the system and is not meant for system capacity increase purposes. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	10	33	7.8	66.0
T-SR-03.055	Kent TS	This investment involves replacement of 230-27.6-27.6kV transformer, 27.6 kV oil-filled circuit breakers, and protection and control equipment. This investment is needed to address equipment that is in poor condition, obsolete and at end of life. This investment is expected to decrease risk of equipment failure and maintain long-term reliability of supply to Entegrus Powerlines Inc. and Hydro One Distribution and eliminate existing maintainability challenges with legacy 27.6kV switchyard that could impact future reliability and performance	1		4	17.8	17.8

T-SR-03.058	Glendale TS	This investment involves the replacement of transformers, medium voltage switching facilities, and protection and control equipment. This investment is needed to address equipment that is in poor condition, obsolete, non-standard and at end of life. The switching facilities are considered legacy and non-standard. In addition, all site protection and control facilities will be replaced with current Hydro One standard equipment. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure.	1		16	28.2	33.5
T-SR-03.061	Mohawk TS	This investment involves the replacement of a 13.8kV low voltage switchgear and protection and control equipment. This investment is needed to address equipment that is in poor condition and at end of life. The investment is expected to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.		6	15	32.4	32.4
T-SR-03.064	Burlington TS	This investment involves the replacement of a 27.6kV low voltage switchgear and protection and control equipment. This investment is needed to address equipment that is in poor condition, obsolete and at end of life. The investment is expected to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.		20	18	14.3	34.7
T-SR-03.066	Dobbin TS	This investment involves the replacement of transformers, 230kV, 115kV, and 44kV oil breakers, AC & DC equipment, and associated protection and control equipment at the 40 year old Dobbin TS. This investment is needed to address assets in poor and deteriorating condition, obsolete and at end of life based on the asset condition assessment. This investment is expected to reduce risk of equipment failure, reduce maintenance costs, and maintain reliability of the BES and to Hydro One customers.	2	5	10	25.9	79.5
T-SR-03.067	Strachan TS	This investment involves the replacement of 110/14-14kV 45/75MVA transformers and protection and control equipment at Strachan TS. This investment is needed to address equipment that is in poor condition and at end of life. The investment is expected to maintain reliability to local customers, mitigate the risk of outages and supply interruptions due to asset failure, and reduce transformer losses.	2			29.7	33.6

T-SR-03.069	Albion TS	This investment involves the replacement of transformers, 13.8kV breakers, and associated protection and control equipment at the 40 year old station Albion TS. This investment is needed to address these assets in poor and deteriorating condition, obsolete and their end of life based on the asset condition assessment. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro Ottawa customers.	2		24	41.9	42.6
T-SR-03.071	Talbot TS	This investment involves the replacement of step-down transformers, disconnect switches, LV switchyard components including breakers, station services, capacitors, and protection and control equipment. This investment is needed to address equipment that is in poor condition and at end of life. The investment is expected to maintain existing system reliability and is not meant for system capacity increase purposes. The benefits of this investment are mitigation of risk associated with equipment in poor condition and removal of obsolete equipment.	2	9	2	63.0	63.7
T-SR-03.072	Havelock TS	This investment involves the replacement of 230/44kV, 50/83 MVA transformers, 44kV breakers, and protection and control equipment at the 55 year old station Havelock TS. This investment is needed to address assets in poor condition, obsolete and at their end of life based on the asset condition assessment. This investment also addresses the recommendation from the recent Peterborough to Kingston Needs Assessment report to replace the T1 and T2 transformers with new, similar size 50/83 MVA units, giving consideration to right-sizing the transformers. The investment is expected to maintain overall station reliability, eliminate operational risks associated with operating EOL equipment, and ensure continued supply reliability to Hydro One Distribution customers in the area.	2	4	16	38.1	44.6
T-SR-03.077	Trout Lake TS	This investment involves the replacement of 230/44kV 75/125 MVA power transformers and 44kV breakers. This investment is needed to address equipment that is in poor and deteriorating condition and at end of life. This investment is expected to maintain reliability to the local customers, and is not expected to increase capacity. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.	2	11	23	9.0	25.9

T-SR-03.078	Lauzon TS	This investment involves the replacement of 230-27.6kV transformers, 27.6kV breakers, 115kV breakers, associated switchgear and protection and control equipment. This investment is needed to address the poor condition of the transformers as indicated by recent condition assessments oil leaks and cooling system issues; and the obsolete and degraded condition of select high voltage and low voltage breakers. The investment is expected to decrease risk of equipment failure and maintain supply reliability to Hydro One Distribution customers in the city of Windsor.	2	9	18	82.8	83.1
T-SR-03.080	Martindale TS	This investment involves the replacement of two transformers. The investment is needed to address transformers in poor and deteriorating condition, obsolete and at end of life. The investment is expected to maintain existing system reliability and is not meant for system capacity increase purposes. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure and removal of legacy obsolete equipment.	2	7		53.1	53.1
T-SR-03.084	Erindale TS	This investment involves the replacement of the protections, one 44kV Breaker, and AC station service at Erindale TS. This investment is needed to address equipment that is obsolete and at end of life. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.			79	6.2	41.0
T-SR-03.086	Morrisburg TS	This investment involves the replacement of AC station service, DC station service, and protection and control equipment at the 60 year old 230/44kV DESN station Morrisburg TS. This investment is needed to address these assets in poor and deteriorating condition and at their end of life and require replacement. The investment is expected to mitigate risk of equipment failure and maintain supply reliability to Hydro One distribution customers in the area.		1	30	12.0	12.0
T-SR-03.088	Beach TS	This investment involves the replacement of transformers, and the medium voltage legacy metalclad switchgear. This investment is needed to address equipment that is in poor condition and at end of life. In addition, the existing metalclad switchgear presents health and safety challenges during routine maintenance. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure.	2	22		57.1	74.7

T-SR-03.090	South March TS	This investment involves the replacement of 230/44kV, 50/67/83 MVA step-down transformers and protection and control equipment at the 49 year old DESN station South March TS. This investment is needed to address assets in deteriorating condition and end of life. The investment is expected to mitigate risk of equipment failure and maintain supply reliability to Hydro One customers in the Ottawa area.	2		26	34.7	35.4
T-SR-03.094	Allanburg TS	The investment involves the replacement of an autotransformer, associated surge arrestors and disconnect switches. This investment is needed to address equipment that is in deteriorating condition and at end of life. The investment is expected to maintain existing system reliability and load serving capability of the system and is not meant for system capacity increase purposes. This investment is expected to reinforce the transmission system in the area, maintain reliability to the bulk system and major industrial customers and mitigate the risk of outages and supply interruptions due to asset failure.	2		14	76.7	76.7
T-SR-03.095	Caledonia TS	This investment involves the replacement of a 230/27.6kV station supply transformer, breaker and protection and control equipment. This investment is needed to address equipment that is in deteriorating condition, obsolete and at end of life. The investment is expected to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.	1		13	12.7	12.7
T-SR-03.096	Finch TS	This investment involves the replacement of the low voltage switchyard and components including 28kV breakers, switches, capacitors, and protection & control equipment at Finch TS. This investment is needed to address equipment that is in poor condition, obsolete and at end of life. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.		11	34	31.7	46.8
T-SR-03.099	Lake TS	This investment involves the replacement of all legacy medium voltage switching facilities at Lake TS that includes the air-insulated switchyard and the legacy metalclad switchgear. This investment is needed to address equipment that is in poor condition, obsolete and at end of life. In addition, the existing medium voltage switching facilities that presents health and safety challenges during routine maintenance. This investment is expected to maintain long-term supply reliability to Alectra Utilities customers and reduce the risk of unplanned outages due to asset failure.	2	17		44.4	75.1

T-SR-03.101	Bramalea TS	This investment involves the replacement of 44kV breakers, 28kV breakers, capacitors, DC station service, and protection and control equipment at Bramalea TS. This investment is needed to address equipment that is in poor condition, obsolete and at end of life. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure			71	5.5	32.6
T-SR-03.103	Duplex TS	This investment involves the replacement of A1-A2 metalclad switchgear and associated equipment at Duplex TS. This investment is needed to address equipment in coordination with Toronto Hydro. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers and reduce the risk of unplanned outages due to asset failure.		2	4	6.7	7.9
T-SR-03.104	Main TS	This investment involves the replacement of A1-A2 metalclad switchgear and associated equipment at Main TS. This investment is needed to address equipment in coordination with Toronto Hydro. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers and reduce the risk of unplanned outages due to asset failure.		2	2	5.2	6.0
T-SR-03.105	Basin TS	This investment involves the replacement of T3 and T5 transformers and associated equipment at Basin TS. This investment is needed to address equipment that is in poor condition and obsolete. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers and reduce the risk of unplanned outages due to asset failure.	2		12	31.0	31.4
T-SR-03.106	Hearst TS	This investment involves the replacement of oil breakers and associated equipment at Hearst TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure in the Sudbury area.		6	6	36.5	43.3
T-SR-03.107	John TS	This investment involves the replacement of A3-A4 metalclad switchgear and associated equipment at John TS. This investment is needed to address equipment in coordination with Toronto Hydro. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers and reduce the risk of unplanned outages due to asset failure.		4	8	13.0	13.3

T-SR-03.108	Wilson TS	This investment involves the replacement of T3 and T4 transformers and associated equipment at Wilson TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2		3	24.9	24.9
T-SR-03.109	Dufferin TS	This investment involves the replacement of the T2 transformer and associated equipment at Dufferin TS. This investment is needed to address equipment in poor condition. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers and reduce the risk of unplanned outages due to asset failure.	1			24.0	24.0
T-SR-03.110	Cecil TS	This investment involves the replacement of 115kV Gas-Insulated Switchgear and associated equipment at Cecil TS. This investment is needed to address equipment that is in poor condition and obsolete. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.		8	12	85.9	118.0
T-SR-03.111	Leslie TS	This investment involves the replacement of the T1 transformer and associated equipment at Leslie TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2		33	49.1	49.1
T-SR-03.112	Sidney TS	This investment involves the replacement of capacitors, DC station service, and protection and control equipment at Sidney TS. This investment is needed to address equipment that is in poor condition, obsolete and at end of life. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure			27	13.5	13.5
T-SR-03.113	Kapuskasing TS	This investment involves the replacement of a 115kV breaker, switches, and protection and control equipment at Kapuskasing TS. This investment is needed to address equipment that is in poor condition. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure		1	10	10.1	10.1
T-SR-03.114	Murray TS	This investment involves the replacement of the T13 and T14 transformers and associated equipment at Murray TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2		15	29.0	29.0

T-SR-03.115	Edgeware TS	This investment involves the replacement of the T1 and T2 transformers and associated equipment at Edgeware TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2			26.8	26.8
T-SR-03.116	Smith Falls TS	This investment involves the replacement of DC station service, instrument transformers, and protection and control equipment at Smiths Falls TS. This investment is needed to address equipment that is in poor condition and at end of life. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure			27	13.8	13.8
T-SR-03.117	Rexdale TS	This investment involves the replacement of the T2 transformers and associated equipment at Rexdale TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	1			14.7	15.6
T-SR-03.118	Agincourt TS	This investment involves the replacement of the T5 and T6 transformers and associated equipment and protection and control equipment at Agincourt TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2		4	28.4	32.2
T-SR-03.119	Carlaw TS	This investment involves the replacement of the T1 and T2 transformers and associated equipment at Carlaw TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2			41.5	52.4
T-SR-03.120	Terauley TS	This investment involves the replacement of the T1, T2, T3 and T4 transformers and associated equipment at Terauley TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	4			62.5	88.4
T-SR-03.121	John TS	This investment involves the replacement of the T3 transformer and associated equipment and protection and control equipment at John TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	1		3	5.3	11.8

T-SR-03.122	Gardiner TS	This investment involves the replacement medium voltage switchgear and associated equipment and protection and control equipment at Gardiner TS in coordination with Kingston Hydro. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure in the Kingston area.		15	13	11.8	34.1
T-SR-03.123	Armitage TS	This investment involves the replacement of the T3 and T4 transformers and associated equipment at Armitage TS. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2			10.6	45.1
T-SR-03.124	Buttonville TS	This investment involves the replacement of the T3 and T4 transformers and associated equipment at Buttonville TS. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2	2		11.1	54.4
T-SR-03.125	Lindsay TS	This investment involves the replacement of the T1 and T2 transformers and associated equipment at Lindsay TS. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2			6.6	30.7
T-SR-03.126	Sarnia Scott TS	This investment involves the replacement of the T6 transformer and associated equipment and protection and control equipment at Sarnia Scott TS. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	1		9	7.6	68.5
T-SR-03.127	Manby TS	This investment involves the replacement medium voltage switchgear and associated equipment and protection and control equipment at Manby TS. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.		11	15	5.7	39.8
T-SR-03.128	Jarvis TS	This investment involves the replacement of the T3 and T4 transformers and associated equipment at Jarvis TS. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	2			23.3	48.1
T-SR-03.129	Newton TS	This investment involves the replacement of high voltage and medium voltage switchgear and associated equipment and protection and control equipment at Newton TS. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.		22	19	7.3	81.5

T-SR-03.130	Stirton TS	This investment involves the replacement of protection and control equipment at Newton TS. This investment is expected to maintain long-term supply reliability to customers and reduce the risk of unplanned outages due to asset failure.	1		8	18.3	28.0
T-SR-03.131	Lisgar TS	This investment involves the replacement of a transformer at Lisgar TS. This investment is needed to address equipment that is in poor condition. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro Ottawa customers.	1			15.3	45.3

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

The investments proposed in this ISD are complex and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.11. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project, the in-service year and the project total estimates for the 2023-2027 and 2028-2032 rate periods. Project maturity is defined by the following project phases:

- Execution (E), which reflects fully approved project work;
- Planning and Definition (P), which reflects non-execution work, regardless of level of upfront development; and
- Complete (C), which reflects that the project has been placed in service

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in Table B1 below in reference to project total variances and overall project schedule variances.

1

Table B1 - Hydro One - Detailed Material Investment Costs ($M)

			Net Capital Investment ($M)							Project Forecast			Prior Project Forecast			
ISD Ref.	**Station Name**	**Actual Pre 2023**	**Act/Fcst 23-27[4]**	**2028**	**2029**	**2030**	**2031**	**2032**	**28-32 Total**	**Project Phase**	**Project Total**	**In Service Year**	**ISD Ref.**	**Prior Project Phase**	**Prior Project Total[5]**	**In Service Year**
T-SR-03.003	Main TS	25.9	**40.9**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	66.8	2026		E	48.0	2024
		Since the Plan was prepared, the forecast cost of this project increased as a result of execution-related factors and equipment cost increases. The project was undertaken in a congested urban setting, resulting in unanticipated design and construction challenges. The compact site footprint restricted material movement and onsite storage which required offsite staging and additional transportation, leading to higher material handling costs. In addition, the site required complex excavation shoring and commissioning activities that exceeded original expectations. These factors, combined with permit delays and installation issues with the first transformer, led to a schedule delay as well. The cost escalations were partially offset through risk-management strategies (e.g., temporary metering and coordinating with a variety of external entities), efficient resource allocation, flexible work planning, and advanced partial in-services resulting in an effective reduction in overall project cost and variance by approximately $4M.														
T-SR-03.005	Wonderland TS	3.9	**1.5**	0.0	0.0	0.0	0.0	0.0	**0.0**	-	-	-		P	27.0	2026
		Project cancelled. The transformers failed while still refining scope and were replaced under a demand replacement program.														
T-SR-03.006	Moose Lake TS	1.5	**25.8**	3.4	0.0	0.0	0.0	0.0	**3.4**	E	30.6	2028		P	9.6	2027
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-03.007	Orangeville TS	30.7	**17.5**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	48.1	2024		E	35.6	2023
		Since the Plan was prepared, the project forecast cost increased due to design refinements and the reconciliation of estimating assumptions. Design refinements were driven by site-specific space constraints as the existing battery rooms were ultimately determined to have insufficient space to safely accommodate the upsized batteries and allow for required maintenance access. As a result, the most cost-effective solution was to install two new prefabricated buildings to house the station batteries. In addition, previously unidentified underground cables were discovered during excavation and required relocation due to the transformer location. The forecast increase was also driven by refinements to the original estimate, including omitted scope of four spill pits and one of two oil water separators, as well as additional construction effort associated with updated work practices and safety standards.														

[4] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.
[5] "Prior Proj. Total" refers to the Project Total when Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

T-SR-03.009	Crowland TS	2.1	**0.3**	0.0	0.0	0.0	0.0	0.0	**0.0**	-	-	-		P	33.9	2026
		Project cancelled to accommodate station upgrade needs.														
T-SR-03.012	Arnprior TS	27.2	**9.1**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	36.3	2023		E	31.4	2023
		During the planning phase, the transformer failed, triggering emergency repairs and expediating the execution of the project. Although soil and ground studies were underway, the results were not available until execution commenced. These findings necessitated changes to the foundation design, resulting in additional engineering and construction costs. Furthermore, as the design matured, additional material requirements were identified. Cost escalations account for approximately $2M of the overall variance. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.014	Rexdale TS	11.8	**46.5**	0.3	0.0	0.0	0.0	0.0	**0.3**	E	58.6	2027		E	33.6	2026
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-03.015	Kirkland Lake TS	7.3	**28.6**	0.0	0.0	0.0	0.0	0.0	**0.0**	E	35.9	2026		E	27.9	2025
		The variance is primarily due to cost escalations which account for approximately $3M of the overall variance and execution refinements resulting from the project's deferral due to portfolio reprioritization. After the resumption of construction activities and detailed reviews of the release-for-construction design packages, updates to the switchyard design were identified to enhance safety and maintainability. In addition, the outage staging plan was revised to reflect current system conditions and constraints. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan. Through scope optimization, Hydro One realized approximately $5M in project savings, effectively reducing the overall project cost and variance.														
T-SR-03.016	Fairbank TS	53.8	**26.0**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	79.8	2024		E	70.6	2024
		The variance is primarily attributable to updated project definition assumptions related to feeder relocations and cutovers and increased field supervision requirements. Design modifications to accommodate temporary facilities required to maintain system reliability during transformer replacements, necessitated by increased load requirements, contributed to the variance as well. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.017	Bridgman TS	38.8	**52.0**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	90.8	2026		E	69.3	2024
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-03.018	Murray TS	0.4	**2.8**	0.5	0.5	5.5	31.1	20.2	**57.8**	P	61.0	2032		P	39.6	2025
		The variance is attributable to cost escalations, the requirement for a larger switchgear configuration to accommodate future feeders and spare breakers, and minor scope additions. The large switchgear configuration supports the planned replacement of the existing transformers with higher-capacity units, needed to accommodate future load growth. Site preparation activities and civil work have since														

		been incorporated into the updated estimate as well. Subsequently, portfolio reprioritization led to the project's deferral. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.019	Lauzon TS	2.8	**67.3**	0.0	0.0	0.0	0.0	0.0	**0.0**	E	70.1	2026		P	64.1	2026
		The variance is primarily due to complex site conditions and additional expansion leading to higher site preparation costs. Local distributor feeder relocations and cost escalation contributed to the variance as well. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan. Through in-service optimization and strong risk management, Hydro One realized approximately $4M in project savings, effectively reducing the overall project cost and variance.														
T-SR-03.020	Longueuil TS	1.0	**28.6**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	29.5	2025		P	24.9	2026
		The variance is primarily due to transformer cost escalations and is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan. Through construction efficiencies, Hydro One realized approximately $4M in project savings, effectively reducing the overall project cost and variance.														
T-SR-03.023	Port Arthur TS #1	0.2	**46.9**	0.0	0.0	0.0	0.0	0.0	**0.0**	E	47.1	2027		P	24.3	2026
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-03.024	Port Hope TS	0.0	**0.0**	0.0	0.7	1.8	11.2	18.5	**32.3**	P	40.5	2033		P	19.6	2031
T-SR-03.025	Manby TS	0.0	**0.0**	0.3	2.5	5.5	21.2	30.5	**60.0**	P	81.7	2033		P	21.8	2029
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Originally, the investment was to upsize and replace two transformers; however, through ongoing condition assessments it was determined the respective switchyards required replacement as well, significantly increasing the scale of this project. Portfolio reprioritization resulted in the project's deferral with cost escalations contributing to the overall variance as well.														
T-SR-03.026	Elliot Lake TS	1.6	**30.1**	0.0	0.0	0.0	0.0	0.0	**0.0**	E	31.7	2026		P	23.5	2026
		The cost increase is driven by cost escalation and changes to the switchyard layout resulting from constructability issues caused by space limitations. The option for yard expansion was determined to be unfeasible due to the adjacent steep valley which would require extensive backfill, compaction, and slope stabilization measures resulting in substantially higher costs and schedule impacts. As a result, an in-situ replacement was determined to be the most cost-effective option. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan. Through construction efficiency and strong risk management, reducing contingency, Hydro One realized approximately $6M in project savings, effectively reducing the overall project cost and variance.														
T-SR-03.027	Preston TS	0.7	**46.3**	0.0	0.0	0.0	0.0	0.0	**0.0**	E	47.0	2027		P	23.7	2026
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-03.028	Wallace TS	0.0	**0.0**	0.3	0.5	2.7	14.9	9.5	**28.0**	P	28.0	2032		P	23.0	2031

T-SR-03.029	Bermondsey TS	0.0	**0.0**	0.2	0.6	5.3	17.8	19.0	**43.0**	P	48.7	2033		P	31.6	2029
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Based on asset conditions, additional scope was added to include the replacement of controls, instrument transformers, and switches. Portfolio reprioritization led to the project's deferral with cost escalations accounting for approximately $7M of the variance.														
T-SR-03.033	Picton TS	0.0	**28.4**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	28.4	2026		P	19.8	2029
		The cost increase is driven by staging complexities associated with stranded load at the station requiring temporary lines and structures, and additional civil work. Cost escalation also contributed approximately $3M of the overall variance; however, it is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan. Through construction efficiencies, Hydro One realized approximately $4M in project savings, effectively reducing the overall project cost and variance.														
T-SR-03.034	Midhurst TS	0.0	**0.4**	0.7	0.8	3.8	7.5	3.7	**16.6**	P	17.0	2032		P	11.0	2025
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Additional scope requirements, including controls, switches, and station services, contributed to the cost increase. Subsequent portfolio reprioritization resulted in its deferral, with cost escalation accounting for approximately $2M of the variance. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.036	Bracebridge TS	0.3	**18.1**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	18.4	2025		P	8.2	2026
		The project was in a preliminary planning phase when the original forecast for the Plan was established. As the project matured, the transformer replacement approach was revised in response to increasing load growth in the area which limited outage availability and transfer capabilities. This led to scope additions, including spill containment, an oil water separator, yard expansion, additional component replacements, and transmission line work. Further cost pressures were driven by cost escalation. Through construction efficiencies and strong risk management, Hydro One realized approximately $5M in project savings, effectively reducing the overall project cost and variance.														
T-SR-03.037	Charles TS	0.8	**42.4**	0.0	0.0	0.0	0.0	0.0	**0.0**	E	43.2	2027		P	27.9	2026
		The project was in a preliminary planning phase when the original forecast for the Plan was established. The forecast cost of this project has increased as a result of procurement cost escalations ($5M for transformers alone) and refined risk assessment and mitigation strategies including the need for bypass and other staging elements resulting from the complex outage requirements. These cost escalations were partially offset through value added engineering to optimize the scope and leveraging procurement opportunities to secure preferred pricing on the transformers resulting in an effective reduction in overall project cost and variance by approximately $8M.The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.038	Manby TS	0.0	**0.0**	0.0	0.0	0.2	0.7	5.0	**5.9**	P	41.7	2035		P	29.4	2031
T-SR-03.039	Russell TS	0.6	**40.3**	0.0	0.0	0.0	0.0	0.0	**0.0**	E	40.8	2027		P	28.6	2026
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Since the Plan was prepared, the forecast cost of this project increased due to refined work definition following the completion of a geotechnical study and unknown site conditions, development of protection, control, and telecom design, and finalizing the staging plan for the required outages. These cost														

		escalations were partially offset by optimizing the project plan and applying effective risk-management strategies that limited the use of project contingency funds, resulting in an effective reduction in overall project cost and variance by approximately $8M. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.040	Duplex TS	0.0	**0.4**	0.3	0.6	3.8	17.4	30.1	**52.2**	P	89.1	2034		P	22.3	2026
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequently, portfolio reprioritization resulted in the project's deferral. The project cost increased due to updated estimates based on recent comparable projects and the incorporation of scope from another investment at the same site. The integrated scope includes the replacement of two additional transformers and associated end of life equipment.														
T-SR-03.041	Lake TS	1.3	**10.6**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	11.9	2024		P	39.9	2026
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-03.042	Bunting TS	2.3	**-2.3**	0.0	0.0	0.0	0.0	0.0	**0.0**	-	-	-		P	44.0	2029
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequently, portfolio reprioritization resulted in the project's deferral.														
T-SR-03.043	Nebo TS	0.0	**0.0**	0.4	2.1	8.4	13.1	12.6	**36.6**	P	36.6	2032		P	24.8	2031
T-SR-03.044	Palermo TS	0.0	**49.9**	0.1	0.0	0.0	0.0	0.0	**0.1**	E	50.0	2027		P	34.3	2027
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Since then, power transformer cost escalations have accounted for approximately $15M of the variance; however, it is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan. Through construction efficiencies and in-service optimization, Hydro One realized approximately $2M in project savings, effectively reducing the overall project cost and variance.														
T-SR-03.045	Carlton TS	3.1	**40.7**	3.3	0.0	0.0	0.0	0.0	**3.3**	E	47.1	2027		P	37.0	2026
		Since the Plan was prepared, the scope of this project increased with the inclusion of a new building designed to accommodate switchgear, and protection and control equipment, while providing capacity for future expansion. The estimated cost of the investment also increased by approximately $5M due to cost escalation, which were partially offset by construction efficiencies resulting in an effective reduction in overall project cost by approximately $6M. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.046	Birmingham TS	0.0	**0.0**	0.1	0.4	0.5	5.4	29.8	**36.1**	P	75.6	2034		P	30.6	2031
T-SR-03.048	Cherrywood TS	0.0	**0.0**	0.5	0.8	5.5	21.8	13.4	**41.9**	P	41.9	2032		P	33.1	2029
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequent portfolio reprioritization resulted in its deferral with cost escalations contributing approximately $3M to the overall variance. Since then, the planning framework has														

		evolved, resulting in the inclusion of site preparation requirements within the updated estimate as needed. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.049	Gage TS	0.0	**0.0**	0.1	0.4	0.4	7.1	41.5	**49.5**	P	76.5	2033		P	32.2	2031
T-SR-03.050	Woodbridge TS	0.0	**1.7**	0.3	2.6	6.5	13.1	13.8	**36.4**	P	38.1	2032		P	12.6	2027
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Since the Plan was prepared, the forecast cost of this project increased as the estimate matured and additional scope requirements were identified. The updated estimate reflects requirements for lines work, protection, control, and telecom upgrades, and additional structures and buses. Additionally, site preparation has since been incorporated into the updated estimate. Cost escalations account for approximately $8M of the overall variance.														
T-SR-03.051	Fairchild TS	0.0	**0.0**	0.2	0.4	0.4	5.2	30.3	**36.5**	P	65.3	2034		P	47.7	2028
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Since then, the scope was expanded to include the replacement of capacitors, controls, and additional switches and surge arresters, as assessed by asset condition. Portfolio reprioritization led to the project's deferral with cost escalations accounting for approximately $10M of the variance. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.052	Cedar TS	0.0	**0.0**	0.5	0.5	4.0	22.3	14.5	**41.8**	P	41.8	2032		P	57.4	2032
T-SR-03.054	Waubaushene TS	0.0	**58.2**	7.8	0.0	0.0	0.0	0.0	**7.8**	P	66.0	2028		P	13.7	2027
		The cost variance is mainly attributable to additional infrastructure driven by load growth in the area, identified through regional planning. In 2022, South Georgian Bay-Muskoka Regional Infrastructure Plan identified the immediate need to provide additional supply capacity. According to the regional loading forecast, larger transformers were needed. The load increase need combined with Hydro One's plans to replace the transformers due to deteriorated condition resulted in a recommended action to install larger transformers at the station. To support this, additional functional requirements were identified such as building a new switchyard with protection, control, and telecom systems, and relocating overhead distribution feeders. Further cost increases occurred as site preparation and distribution lines were added to the planning allowance, along with cost escalation of major material, such as power transformers and development of land appraisal with the property owner.														
T-SR-03.055	Kent TS	0.0	**0.0**	0.7	0.8	4.1	8.1	4.0	**17.8**	P	17.8	2032				
T-SR-03.058	Glendale TS	2.6	**2.7**	0.3	3.7	16.3	7.9	0.1	**28.2**	P	33.5	2031		P	52.9	2027
		The project was deferred due to portfolio reprioritization. To direct resources and funding toward high-risk assets, the project scope was revised to replace only one transformer as it was the main driver for station renewal work at Glendale TS and was dedicated to supplying a major customer in the area, making it a high-priority replacement, while keeping the second transformer as is and removing the other two transformers. In addition, the transformer location was changed, enabling the existing transformer to remain on load until the new transformer is placed in-service, reducing the overall project cost.														
T-SR-03.060	Dundas TS	0.0	**0.0**	0.0	0.0	0.4	0.6	3.4	**4.4**	P	35.5	2034		P	10.3	2031

T-SR-03.061	Mohawk TS	0.0	**0.0**	0.0	0.0	8.5	17.3	6.6	**32.4**	P	32.4	2032		P	7.0	2031
T-SR-03.062	Bathurst TS	0.0	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.0**	-	-	-		P	15.1	2027
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequently, portfolio reprioritization resulted in the project's deferral.														
T-SR-03.064	Burlington TS	0.0	**0.0**	0.0	0.0	0.4	0.6	13.3	**14.3**	P	34.7	2034		P	8.8	2028
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequently, portfolio reprioritization resulted in the project's deferral. The variance is attributable to the ongoing refinement of condition assessments and cost assumptions as the investment advances through early planning stages.														
T-SR-03.066	Dobbin TS	0.0	**53.6**	24.7	1.2	0.0	0.0	0.0	**25.9**	E	79.5	2028		P	62.0	2028
		The project was in a preliminary planning phase when the original forecast for the Plan was established. The scope of the investment increased to facilitate new work directed by the IESO. Originally, the investment addressed only end of life transformers; however, the scope was expanded to include five circuit breaker replacements to facilitate the connection of two new lines between Dobbin TS and Clarington TS. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.067	Strachan TS	0.0	**0.0**	0.2	0.6	4.4	11.8	12.6	**29.7**	P	33.6	2033		P	31.3	2031
T-SR-03.069	Albion TS	0.0	**0.7**	1.6	10.2	20.2	9.9	0.0	**41.9**	P	42.6	2031		P	42.3	2031
T-SR-03.071	Talbot TS	0.0	**0.7**	3.3	20.1	28.4	11.3	0.0	**63.0**	P	63.7	2031		P	28.5	2032
T-SR-03.072	Havelock TS	0.0	**0.0**	0.2	0.6	2.6	15.6	19.0	**38.1**	P	44.6	2033		P	14.4	2030
T-SR-03.077	Trout Lake TS	0.0	**0.0**	0.0	0.0	0.7	1.3	7.0	**9.0**	P	25.9	2034				
T-SR-03.078	Lauzon TS	0.0	**0.4**	0.6	6.2	37.0	34.5	4.4	**82.8**	P	83.1	2032		P	24.7	2028
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequently, portfolio reprioritization resulted in the project's deferral. The variance is attributable to the ongoing refinement of condition assessments and cost assumptions as the investment advances through early planning stages.														
T-SR-03.079	Galt TS	0.0	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.0**	-	-	-		P	12.9	2028
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequently, portfolio reprioritization resulted in the project's deferral.														
T-SR-03.080	Martindale TS	0.0	**0.0**	0.6	1.6	10.9	26.1	14.0	**53.1**	P	53.1	2032		P	26.1	2029

		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequent portfolio reprioritization resulted in its deferral with cost escalations accounting for approximately $6M of the variance. Additional scope requirements were incorporated, including a breaker, switches and instrument transformers, as assessed by asset conditions.														
T-SR-03.082	Campbell TS	0.3	**0.0**	0.0	0.0	0.4	0.6	2.4	**3.4**	P	25.7	2034		P	20.6	2029
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequently, portfolio reprioritization resulted in the project's deferral. The variance is attributable to the ongoing refinement of condition assessments and cost assumptions as the investment advances through early planning stages.														
T-SR-03.084	Erindale TS	0.0	**0.0**	0.0	0.0	0.3	0.7	5.2	**6.2**	P	41.0	2035		P	28.3	2031
T-SR-03.085	Gardiner TS	0.0	**39.2**	0.0	0.0	0.0	0.0	0.0	**0.0**	E	39.2	2026		P	61.9	2025
		See Detailed Individual Investment Variance Summary in TSP Section 2.9 Attachment 2.														
T-SR-03.086	Morrisburg TS	0.0	**0.0**	0.3	0.5	1.1	6.2	3.9	**12.0**	P	12.0	2032		P	10.8	2030
T-SR-03.088	Beach TS	0.0	**0.0**	0.5	2.1	6.5	25.7	22.3	**57.1**	P	74.7	2033		P	50.2	2031
T-SR-03.090	South March TS	0.0	**0.7**	2.1	12.3	15.0	5.2	0.0	**34.7**	P	35.4	2031		P	7.2	2030
T-SR-03.094	Allanburg TS	0.0	**0.0**	0.5	0.5	7.4	41.4	26.9	**76.7**	P	76.7	2032				
T-SR-03.095	Caledonia TS	0.0	**0.0**	0.6	0.7	3.4	8.0	0.0	**12.7**	P	12.7	2032		P	12.5	2029
T-SR-03.096	Finch TS	0.3	**0.1**	0.0	0.0	1.1	13.7	16.9	**31.7**	P	46.8	2035				
T-SR-03.099	Lake TS	0.0	**8.9**	0.5	2.1	8.6	16.4	16.9	**44.4**	P	75.1	2034		P	33.0	2032
T-SR-03.101	Bramalea TS	0.0	**0.0**	0.0	0.0	0.3	0.6	4.6	**5.5**	P	32.6	2035		P	21.8	2031
T-SR-03.103	Duplex TS	0.0	**1.2**	2.0	4.7	0.0	0.0	0.0	**6.7**	P	7.9	2029		P	5.1	2031
T-SR-03.104	Main TS	0.0	**0.8**	0.4	4.1	0.7	0.0	0.0	**5.2**	P	6.0	2030		-	-	-
T-SR-03.105	Basin TS	0.0	**0.4**	1.0	9.2	20.9	0.0	0.0	**31.0**	P	31.4	2030		P	23.4	2027
		The cost increase is primarily driven by updated estimates, incorporating site specific complexities such as urban location, indoor transformers, and space constraints. Subsequent portfolio reprioritization led to the project's deferral with cost escalations contributing														

		approximately $2M to the variance. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
T-SR-03.106	Hearst TS	0.5	**6.3**	15.3	15.2	6.0	0.0	0.0	**36.5**	P	43.3	2030		P	13.2	2028
		Since the Plan was prepared, the forecast cost of this project increased due to a change in execution strategy required to address the replacement of additional end of life assets. The scope underlying the Plan included the replacement of three breakers, associated switches, three surge arrestors, and end of life protection facilities. Subsequently, the investment was deferred due to portfolio reprioritization. During the deferral period, the station experienced multiple breaker failures and further asset condition assessments identified significant deterioration across the switchyard. These assessments determined 90% of the switchyard had reached end of life and required replacement. As a result, replacing select assets was no longer the prudent long-term solution, and a greenfield approach to building a new switchyard was determined to provide the most reliable and safe means of addressing operational needs.														
T-SR-03.107	John TS	0.0	**0.3**	0.4	0.6	7.3	4.8	0.0	**13.0**	P	13.3	2031		-	-	-
T-SR-03.108	Wilson TS	0.0	**0.0**	0.3	0.6	9.4	14.5	0.0	**24.9**	P	24.9	2031		-	-	-
T-SR-03.109	Dufferin TS	0.0	**0.0**	0.2	0.6	5.1	12.2	6.0	**24.0**	P	24.0	2032				
T-SR-03.110	Cecil TS	0.1	**32.0**	13.9	19.0	20.0	24.0	9.0	**85.9**	P	118.0	2032		P	50.0	2029
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Since then, a feasibility assessment was completed which confirmed completing the switchyard replacement in situ is not possible due to risks on reliability and operation of the greater Toronto area. To mitigate safety, outage, and system reliability risks while addressing site constraints, a greenfield replacement approach was selected. Additional funds have been allocated to account for acquisition of adjacent property and development of a greenfield solution based on historical costs of comparable projects. Cost escalation also contributed approximately $22M to the overall variance.														
T-SR-03.111	Leslie TS	0.0	**0.0**	0.6	1.5	10.0	24.1	12.9	**49.1**	P	49.1	2032		-	-	-
T-SR-03.112	Sidney TS	0.0	**0.0**	0.4	0.6	1.2	6.9	4.5	**13.5**	P	13.5	2032		P	3.2	2030
T-SR-03.113	Kapuskasing TS	0.0	**0.0**	0.3	0.5	0.9	5.1	3.3	**10.1**	P	10.1	2032		P	6.3	2030
T-SR-03.114	Murray TS	0.0	**0.0**	0.5	0.4	9.2	12.5	6.4	**29.0**	P	29.0	2032		P	25.7	2031
T-SR-03.115	Edgeware TS	0.0	**0.0**	0.4	0.6	2.5	14.1	9.2	**26.8**	P	26.8	2032		-	-	-
T-SR-03.116	Smith Falls TS	0.0	**0.0**	0.4	0.6	1.3	7.0	4.6	**13.8**	P	13.8	2032		P	9.2	2028
T-SR-03.117	Rexdale TS	0.0	**0.0**	0.3	0.6	3.4	5.8	4.6	**14.7**	P	15.6	2033		-	-	-

T-SR-03.118	Agincourt TS	0.0	**0.0**	0.2	0.6	4.3	11.3	12.0	**28.4**	P	32.2	2033		P	25.4	2032
T-SR-03.119	Carlaw TS	0.0	**0.0**	0.2	0.5	1.4	14.8	24.5	**41.5**	P	52.4	2033		P	24.8	2032
T-SR-03.120	Terauley TS	0.0	**0.0**	0.2	0.5	1.8	15.0	45.1	**62.5**	P	88.4	2033		-	-	-
T-SR-03.121	John TS	0.0	**0.0**	0.0	0.0	0.4	0.6	4.3	**5.3**	P	11.8	2033		-	-	-
T-SR-03.122	Gardiner TS	0.0	**0.0**	0.0	0.1	0.5	1.6	9.6	**11.8**	P	34.1	2034		-	-	-
T-SR-03.123	Armitage TS	0.0	**0.0**	0.0	0.0	0.6	1.5	8.5	**10.6**	P	45.1	2034				
T-SR-03.124	Buttonville TS	0.0	**0.0**	0.0	0.0	0.6	1.4	9.0	**11.1**	P	54.4	2034		-	-	-
T-SR-03.125	Lindsay TS	0.0	**0.0**	0.0	0.0	0.6	0.9	5.1	**6.6**	P	30.7	2034		-	-	-
T-SR-03.126	Sarnia Scott TS	0.0	**0.0**	0.0	0.0	0.5	0.6	6.6	**7.6**	P	68.5	2034		P	45.6	2031
T-SR-03.127	Manby TS	0.0	**0.0**	0.0	0.0	0.2	0.6	4.9	**5.7**	P	39.8	2035				
T-SR-03.128	Jarvis TS	0.0	**0.0**	0.0	0.0	0.6	9.0	13.7	**23.3**	P	48.1	2035				
T-SR-03.129	Newton TS	0.0	**0.0**	0.0	0.0	0.1	1.6	5.6	**7.3**	P	81.5	2035		P	40.3	2030
T-SR-03.130	Stirton TS	0.0	**0.0**	0.0	0.0	0.6	2.7	15.0	**18.3**	P	28.0	2035		P	1.9	2029
T-SR-03.131	Lisgar TS	0.0	**0.0**	0.0	0.2	0.6	2.0	12.5	**15.3**	P	45.3	2034		-	-	-
-	Norfolk TS	0.0	**0.0**	0.0	0.0	0.4	0.7	3.8	**4.8**	P	39.6	2034		P	28.5	2029
		The project was in a preliminary planning phase when the original forecast for the Plan was established. Subsequent portfolio reprioritization resulted in its deferral with cost escalations contributing approximately $5M to the overall variance. Since then, the planning framework has evolved, resulting in the inclusion of site preparation requirements within the updated estimate as needed. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														
-	Strachan TS	0.2	**16.0**	0.1	0.0	0.0	0.0	0.0	**0.1**	E	16.3	2027		P	10.9	2025
		The project scope was refined to address a range of station infrastructure, electrical, civil, and protection and control requirements. The variance is consistent with expectations, given the maturity and accuracy range of the estimate class underlying the Plan.														

-	Thorold TS	24.2	**19.5**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	43.8	2024		E	31.8	2024
		The variance is primarily attributable to execution complexities arising from site-specific conditions and design refinements identified during execution. Due to the age of the site, a safety hazard was identified in the metalclad building, requiring additional structural assessment and remediation planning. In addition, changes in legislation related to soil management (Ontario Regulation 406/19 “On-Site and Excess Soil Management”) resulted in additional environmental support and management. Further cost increases were driven by design refinements following the issuance of released-for-construction drawings leading to in-design modifications and additional construction costs. Cost escalations account for approximately $2M of the overall variance.														
-	Wingham TS	13.5	**20.7**	0.0	0.0	0.0	0.0	0.0	**0.0**	C	34.3	2024	-	E	23.0	2024
		The variance is primarily due to cost escalation and site-specific design modifications that were required due to constructability and execution related factors associated with outage constraints and safety concerns. Detailed site assessments determined that the original in-situ replacement approach for the station service transformer was not feasible due to outage limitations, resulting in a revised design to mitigate schedule and outage risks. Additional modifications were also required to address space constraints in the existing relay building and the safety issue posed by high hydrogen concentration levels at the location. This included the installation of a separate battery building and additional station services.														

APPENDIX C – HOSSM TRANSMISSION STATION RENEWAL - CONNECTION STATIONS

As described in TSP 2.10, Hydro One has been operationally integrated with HOSSM since October 1, 2018. However, HOSSM remains financially and legally separate until a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One.

HOSSM continues to be the licensed owner and operator of its transmission system, however, it relies on Hydro One to carry out the day-to-day operations, pursuant to affiliate service agreements as outlined in Exhibit D-02-03. Although HOSSM is distinct and its approved revenue requirement is established separately, many processes including the asset management, planning and work execution approaches are common and integrated with Hydro One Transmission and are described within Hydro One's SPF and TSP.

Since HOSSM's programs are operationally integrated with Hydro One, the investment need, investment description, outcomes, alternatives and execution risks and mitigation described above for Hydro One in Sections 2.0, 3.0, 4.0, 6.0 and 7.0, respectively, are applicable to HOSSM's stations renewal projects.

Table C-1 below summarizes HOSSM's Actual and Forecast capital expenditures for the 2022-2026 rate period and the forecast capital expenditures for the 2027-2032 rate period.

Table C1 - HOSSM Investment Expenditures

($M)	2027	2028	2029	2030	2031	2032	Total 27-32
Gross Capital Expenditures	15.8	29.7	14.6	15.3	15.7	6.7	98.1
Less Removals	0.3	0.9	0.3	0.1	0.1	0.1	2.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**15.5**	**28.8**	**14.3**	**15.2**	**15.6**	**6.6**	**96.1**

The factors influencing the cost of this investment for HOSSM are the same as Hydro One and reflected in Section 5.0 above.

Table C-2 outlines the scope, need and outcome for each of HOSSM's station renewal investments planned for the 2027-2032 period and Table C-3 includes the detailed cost information for each investment.

1 **Table C2 - HOSSM DESCRIPTION OF FORECAST INVESTMENTS**

ISD Ref.	Station Name/Circuit	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
T-SR-03.HOSSM.01	**Patrick St. TS Breaker Upgrade**	This investment involves the replacement of circuit breakers at Patrick St. TS. This investment is needed to address equipment that is obsolete and in poor condition. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to HOSSM customers.	-	4	-
T-SR-03.HOSSM.02	**Goulais Component Replacement**	This investment involves the replacement of three single-phase transformers, with a new three-phase unit, provisions for a Mobile Unit Substation (MUS) connection, and protection and control equipment at Goulais TS. This investment is needed to address equipment that is obsolete and in poor condition. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to HOSSM customers.	1	-	4
T-SR-03.HOSSM.03	**Northern Ave T1 Replacement**	This investment involves the replacement of the existing T1 transformers and associated SCADA equipment at Northern Ave Station. This investment is needed to address equipment in poor condition. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to HOSSM customers.	1	-	5
T-SR-03.HOSSM.04	**Clergue TS M/C Switchgear Replacement**	This investment involves the replacement of metalclad switchgear at Clergue TS. This investment is needed to address equipment that is obsolete and in poor condition. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to HOSSM customers.	-	10	5
T-SR-03.HOSSM.05	**Hollingsworth TS Prot Upgrade**	This investment involves the replacement of protection and control equipment at Hollingsworth TS. This investment is needed to address equipment in poor condition. This investment is expected	-	-	5

		to reduce the risk of equipment failure and maintain reliability of supply to HOSSM customers.			
T-SR-03.HOSSM.06	**Watson TS Metalclad Replacement**	This investment involves the replacement of metalclad switchgear at Watson TS. This investment is needed to address equipment that is obsolete and in poor condition. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to HOSSM customers.	-	12	-
T-SR-03.HOSSM.07	**Patrick St TS PCT upgrade**	This investment involves the replacement of protection, control and telecom equipment at Patrick St. TS. This investment is needed to address equipment that is obsolete and in poor condition. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to HOSSM customers.	-	-	8

1 **Table C3 - HOSSM - Detailed Material Investment Costs ($M)**

ISD Ref.	Station	Net Capital Investment								Project Forecast		
		22-26 Total	2027	2028	2029	2030	2031	2032	27-32 Total	Type	Proj. Total	In-Service Year
T-SR-03.HOSSM.01	Patrick St TS Breaker Upgrade	0.6	1.7	3.1	3.0	2.9	2.2	-	12.9	P	13.6	2031
T-SR-03.HOSSM.02	Goulais Component Replacement	1.7	8.0	7.5	-	-	-	-	15.5	P	17.2	2028
T-SR-03.HOSSM.03	Northern Ave T1 Replacement	0.3	0.0	0.0	0.0	0.2	0.6	3.0	3.8	P	8.7	2032
T-SR-03.HOSSM.04	Clergue TS M/C Switchgear Replacement	4.8	5.8	18.0	7.8	0.0	0.0	0.0	31.6	P	37.6	2029
T-SR-03.HOSSM.05	Hollingsworth TS Prot Upgrade	0.0	0.0	0.0	0.0	0.7	0.6	0.0	1.3	P	1.3	2033
T-SR-03.HOSSM.06	Watson TS Metalclad Replacement	0.0	0.0	0.3	3.0	11.0	11.3	2.3	27.9	P	27.8	2033
T-SR-03.HOSSM.07	Patrick St TS PCT upgrade	0.0	0.0	0.0	0.5	0.3	1.0	1.3	3.1	P	3.6	2033

T-SR-04	WOOD POLE STRUCTURE REPLACEMENTS
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2027	2028	2029	2030	2031	2032	Total
Hydro One	-	89.7	91.5	93.4	95.2	97.1	467.0
HOSSM[1]	0.8	4.3	4.4	4.5	4.6	4.7	23.4

Summary:

This investment involves the replacement of Hydro One wood pole structures identified to be in poor condition. The primary trigger of the investment is the poor and worsening condition of existing wood poles, which must be replaced to maintain system reliability and mitigate potential public safety risks. The investment is expected to maintain system reliability and reduce safety risk to employees and the public associated with failing structures.

The proposed pacing over the 2028-2032 planning period is supported by the following considerations:

1. **Addressing the Growing Volume of Poor Condition Wood Poles**
   Over the 2023-2027 rate period, the number of Hydro One poor condition wood poles has increased by 7% to approximately 7,445. The growth in the poor condition population is outpacing replacement. These assets will continue to deteriorate over time, increasing both safety and reliability risks if replacements are deferred. Further, approximately 7,748 wood poles remain categorized as “Need Assessment”, representing approximately 20% of the fleet. As ongoing inspections and condition assessments continue, additional poor condition poles are expected to be identified, further reinforcing the need for an elevated replacement rate.

[1] See Appendix C for a description of HOSSM’s wood pole replacement program.

2. **Addressing Deferred Replacements from the 2023-2027 Rate Period**
   Actual replacement volumes in the 2023-2027 rate period were lower than planned due to the reprioritization of investments as described in TSP Section 2.9. This contributed to the larger population of poor condition poles described in the preceding paragraph.

The proposed pace of this investment is necessary to effectively manage the current population of poor condition poles and to prevent further accumulation of deteriorated assets.

1.0 OVERVIEW

Wood pole structures support transmission lines by elevating conductors above ground, ensuring adequate clearance from obstacles and proper separation between circuit components. These structures come in a variety of designs, sizes, and configurations and are commonly used for transmission voltages ranging from 115 kV to 230 kV.

Over time, wood structures naturally deteriorate. The rate of deterioration depends on many factors including location, weather, wood species, treatment, insects and wildlife. A wood pole is in poor condition when there is rotting or structural damage, such as cracks or breaks in the pole or cross-arm, when woodpecker damage has compromised the pole's integrity, or when there is insufficient shell thickness near the ground line.

The Wood Pole Structure Replacement Program replaces Hydro One wood structures classified as poor condition based on Hydro One's condition-based asset management strategy. To ensure Hydro One maintains system reliability and reduces safety risk to its employees and the public, this investment targets the replacement of 1,112 wood structures each year, totaling 5,560 wood structures over the 2028-2032 planning period. Together with line refurbishment projects discussed in ISD T-SR-13, this investment is intended to address the full population of currently identified poor condition wood structures.

2.0 INVESTMENT NEED

Hydro One's transmission system contains approximately 38,550 wood pole structures. Wood Pole Structure Replacement is condition-driven, informed by ongoing inspections and assessments. Figure 1 presents the current condition profile of the Hydro One wood structure fleet. As outlined in TSP Section 2.2.4.3, Hydro One performs condition assessments and inspections to identify wood structures that exhibit deterioration. Based on the most recent wood pole condition data, approximately 7,445 wood structures – representing 19% of the total population – are classified as being in poor condition. This represents a 7% increase relative to the poor condition population identified in the 2023–2027 period. The increase is primarily attributable to recent inspections of wood structures with previously unknown condition ratings, which identified additional poor condition

structures. As condition assessments and inspections continue, the number of wood structures identified as being in poor condition is expected to increase.

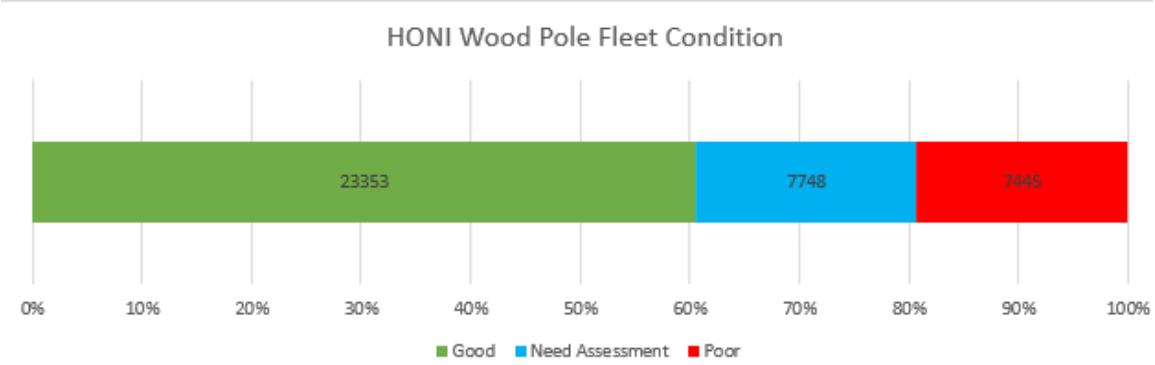

Figure 1: Hydro One Wood Pole Fleet Condition Status

Many transmission wood structures support radial circuits, making them critical to system reliability. A failure of a wood pole or cross-arm can directly result in customer outages. For industrial customers, such outages may force production shutdowns until power is restored, leading to significant operational costs. Similarly, for local distribution customers, these events can disrupt power supply to small towns and remote communities, adversely impacting daily life and essential services.

Transmission wood pole structures are also frequently located in publicly accessible areas, making them critical to public safety. A structural failure could pose severe safety risks, including the risk of serious injury to members of the public or Hydro One crews working in the vicinity. Figures 2-4 below illustrate the failures of wood pole structures.

Given these risks, continued investment is required to proactively replace poor condition wood pole structures before failure occurs. This work aligns with Hydro One's established planning process, which prioritizes assets based on condition, risk, and system impact. By continuing with this investment, Hydro One ensures continued delivery of reliable service to customers while mitigating avoidable public safety risks.

Figure 2: Wood Pole Failure on Circuit P4S in 2020

Figure 3: Wood Pole Failure on Circuit K6Z in 2023

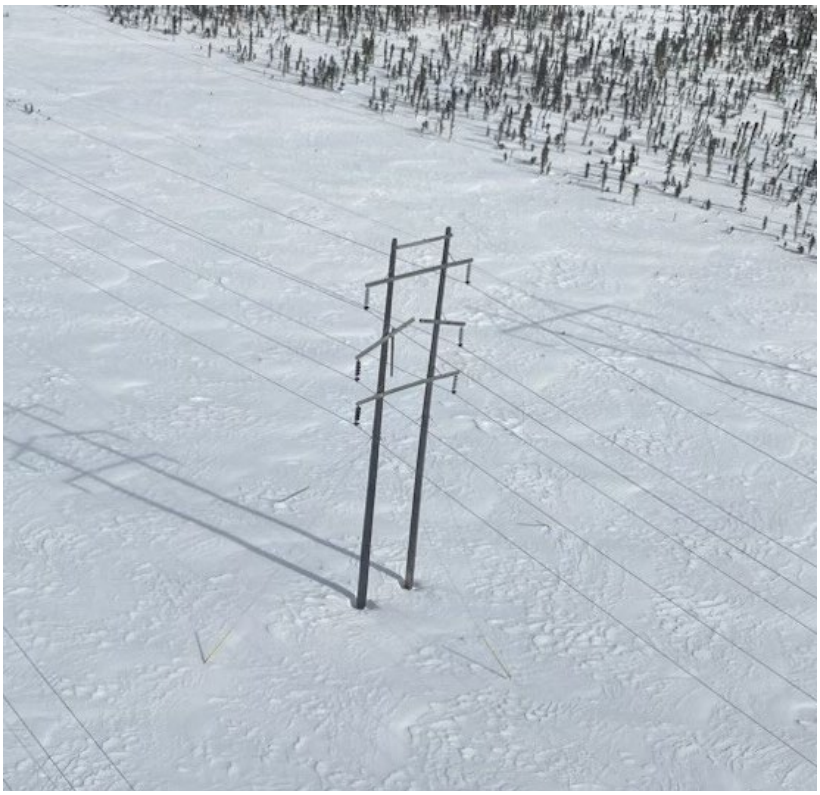

Figure 4: Wood Pole Arm Failure on Circuit D3H in 2025

As further described in TSP Section 2.3, Guidehouse Canada Ltd. and First Quartile Consulting conducted a benchmarking study for Hydro One regarding the replacement rate and demographics of transmission wood pole structures in comparison with a representative comparison group of North American utilities. Two of the key findings are as follows:

- Hydro One's expected service life for wood pole structures of approximately 50 years is near the median of the comparison group.
- Hydro One's wood pole structure replacement rate of approximately 2.2%–2.4% annually (2024 actual and 2025–2029 planned) is broadly in line with the comparison group median of approximately 2%. The study notes that, with 19% of structures already in poor condition and more poles expected to deteriorate over time, overall replacement needs are likely to increase.

3.0 INVESTMENT DESCRIPTION

Hydro One will continue replacing wood pole structures identified as being in poor condition through condition assessments and field inspections. Given the large number of poor condition poles in the system, replacements will be prioritized based on circuit criticality and public safety risk. To enhance reliability and longevity, more composite poles will be deployed, as they are resistant to woodpecker damage and offer a longer expected service life compared to traditional wood structures.

In the 2023-2027 period, Hydro One planned to complete 943 wood pole structure replacements per year. However, based on actuals and the remaining forecast for the 2023-2027 period, Hydro One now expects to complete approximately 789 wood pole structures per year. This is primarily due to the reprioritization of capital expenditures required to address increasing demand for non-discretionary and externally-driven investments, coupled with significant cost escalation, as described in TSP Section 2.9. The following factors also contributed to lower replacement volumes or higher costs than originally planned:

- Increased number of installations involving difficult terrain and access, which resulted in additional labour hours as well as higher contract costs associated with accessing and setting up remote work headquarters, which can include ice roads, bypasses and helicopter deliveries.
- Wood pole shortages accelerated the deployment of composite poles, resulting in capital expenditures exceeding original 2023-2027 planning assumptions due to the higher cost of installing composite poles.

During the 2028-2032 planning period, Hydro One plans to replace approximately 1,112 wood pole structures each year, totaling 5,560 structures over the 2028-2032 planning period.

The proposed pacing is supported by the following considerations:

1. **Addressing the Growing Volume of Poor Condition Wood Poles**
   There are currently approximately 7,445 wood pole structures assessed to be in poor condition. The poor condition population increased over the 2023-2027 rate period by 7%. These assets will continue to deteriorate over time, increasing both safety and reliability risks if replacements are deferred. Further, approximately 7,748 wood pole structures remain categorized as "Need Assessment", representing approximately 20% of the fleet. As ongoing inspections and condition assessments continue, additional poor condition poles are expected to be identified, further reinforcing the need for an elevated replacement rate.

2. **Addressing Deferred Replacements from the 2023-2027 period**
   As outlined above, actual replacement volumes in the 2023-2027 period were lower than planned, resulting in a larger population of poor condition poles. The proposed pace of investment is necessary to prevent further accumulation of deteriorated assets during the 2028-2032 planning period and to effectively manage the known population of poor condition poles.

The investment's 2023-2027 plan and actual/forecast replacement levels as well as the planned replacement levels for the 2028-2032 period are summarized in Table 1.

Table 1 - Hydro One - Wood Pole Structure Replacements

Zone	Component	Plan[2] 23-27	Act/Fcst[3] 23-27	Total 28-32
Hydro One	Wood Pole Structures	4,717	3,943	5,560
	% of Fleet (%)	12.2	10.3	14.4

[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) amounts.

4.0 OUTCOMES

As a result of the investment, Hydro One aims to achieve the following outcomes:

- Maintain system and customer reliability by replacing poor condition wood pole structures and mitigating outages caused by failing wood pole structures.
- Reduce the likelihood of employee and public safety incidents related to failing wood pole structures.

4.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 2 - Outcomes Summary

Customer Focus	• Reduce public and worker safety risk associated with wood pole failures. • Maintain customer reliability by replacing poor condition wood poles.
Operational Effectiveness	• Maintain system reliability by replacing poor condition wood poles • Proactive wood pole replacement will reduce emergency restoration frequency.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence and the TSC to maintain the reliability and integrity of its transmission system.

5.0 EXPENDITURE PLAN

Table 3 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 planning period. Costs are based on historical replacement costs.

Table 3 - Hydro One - Investment Expenditures[4]

($M)	Plan[5] 23-27	Act/Fcst[6] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	313.1	355.1	97.5	99.5	101.5	103.5	105.6	507.6
Less Removals	25.1	28.2	7.8	8.0	8.1	8.3	8.4	40.6
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**288.1**	**326.9**	**89.7**	**91.5**	**93.4**	**95.2**	**97.1**	**467.0**

Over the 2023-2027 rate period, Hydro One expects forecast and actual expenditures to be $38.8M higher than plan due to increased actual replacement costs driven by:

- An increased number of installations involving difficult terrain and access resulting in more labour hours and higher contract costs for the setup and access for remote work headquarters, as described in Section 3.0 above.
- The accelerated deployment of composite poles due to higher costs of composite pole installations relative to wood poles.
- Hydro One has experienced higher and sustained inflationary pressures relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historic material cost escalation trends are described in SPF Section 1.8.3, including transmission and distribution poles, which have increased by 45% on average since 2020.

In the 2028-2032 period, Hydro One expects capital expenditures to be $140.1M higher than 2023-2027 actuals and forecast due to the increased volume of poor condition poles

[4] Figures presented in the tables may not sum to the totals shown due to rounding.
[5] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[6] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

to be replaced during the 2028-2032 period, the increased deployment of composite poles, and the inflationary pressures outlined above.

The factors influencing the cost of the investment include:

- Structure type – The cost varies depending on the design and material (i.e., whether it is single-pole or multi-pole structure and whether it uses wood or composite pole). Dead-end structures also tend to be more difficult and costly to replace due to their greater execution complexity.
- Pole size – There are various pole heights depending on the voltage level and ground clearance requirements, and larger poles may require heavier equipment to replace.
- Geography of the pole location – Accessibility is a key cost driver, as clearing brush or constructing access roads can add significant cost. Rock terrain also increases costs due to the additional civil work required to excavate and prepare the pole-setting hole.
- Environmental restrictions – Crossing an environmentally sensitive area requires time and money to be spent on permits.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

The “Do Nothing” option requires reactive pole replacement, which involves waiting for the wood pole structures in poor condition to fail and then replacing the failed structures on a reactive basis. This alternative has been rejected since the reactive management of transmission lines wood pole structures would lead to increased asset failures resulting in elevated safety and reliability risks. In addition, as wood pole structures deteriorate, emergency restorations and trouble calls would increase. This has a direct and significant impact on customers, who may be faced with long outages due to the radial nature of many wood pole lines.

ALTERNATIVE 2: PLANNED WOOD POLE STRUCTURE REPLACEMENT (RECOMMENDED)

The replacement of wood pole structures based on condition and risk mitigation assessments is the preferred undertaking. This option involves the planned replacement of poor condition wood pole structures based on risk mitigation assessments. This alternative will address poor condition wood pole structures and mitigate associated safety and reliability risks, while balancing asset needs, resource availability, and cost impacts to customers. This alternative is recommended, as it will maintain the safety and reliability of the transmission system.

7.0 EXECUTION RISK AND MITIGATION

Risks that can impact the execution of the investment include access to the assets depending on the season, and equipment outage availability. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial investment planning phase where all known risks are identified and mitigation plans are developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan aims to minimize the loss of supply to the customer (i.e., switching a customer to an alternative supply). Outage planning also aims to synchronize Hydro One supply outages with customers' planned maintenance driven outages.

APPENDIX C – HOSSM's Wood Pole Structure Replacement Program

As described in TSP 2.10, Hydro One has been operationally integrated with HOSSM since October 1, 2018. However, HOSSM remains financially and legally separate until a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One.

HOSSM continues to be the licensed owner and operator of its transmission system, however, it relies on Hydro One to carry out the day-to-day operations, pursuant to affiliate service agreements as outlined in Exhibit D-02-03. Although HOSSM is distinct and its approved revenue requirement is established separately, many processes including the asset management, planning and work execution approaches are common and integrated with Hydro One Transmission and are described within Hydro One's SPF and TSP.

Since HOSSM's programs are operationally integrated with Hydro One, the investment need, investment description, outcomes, and execution risks and mitigation described above for Hydro One in Sections 2.0, 3.0, 4.0 and 7.0, respectively, are applicable to HOSSM's wood pole structure replacement program.

HOSSM's Wood Pole Fleet Condition status is shown below in Figure C-1.

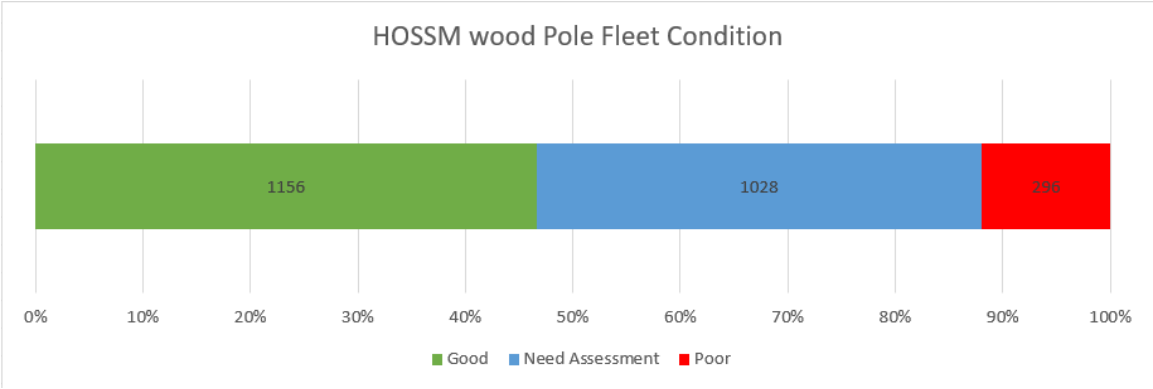

Figure C-1: HOSSM Wood Pole Fleet Condition Status

HOSSM's 2023-2026 actual/forecast replacement levels and planned replacement levels for the 2027-2032 period are summarized in Table C-1.

Table C-1 - HOSSM - Wood Pole Structure Replacements

Zone	Component	Act/Fcst[7] 22-26	Total 27-32
HOSSM	Wood Pole Structures	35	260
	% of Fleet (%)	1.4	10.4

During the 2022-2026 period, HOSSM expects to complete approximately 35 wood pole structure replacements. Replacement volume for the period was impacted by capital reprioritization to accommodate other capital work as described in TSP Section 2.10.

During the 2027-2032 period, HOSSM plans to replace approximately 43 wood pole structures each year on average, totaling 260 structures, addressing the majority of the currently identified poor condition poles as set out in Figure C-1.

Table C-2 below summarizes HOSSM's planned and forecast net capital expenditures for the 2022-2026 rate period and the forecast net capital expenditures for the 2027-2032 rate period. Capital expenditures for the 2027-2032 period are based on historical replacement costs.

Table C-2 - HOSSM - Investment Expenditures

($M)	Act/Fcst[8] 22-26	2027	2028	2029	2030	2031	2032	Total 27-32
Gross Capital Expenditures	6.6	0.9	4.7	4.8	4.9	5.0	5.1	25.4
Less Removals	0.4	0.1	0.4	0.4	0.4	0.4	0.4	2.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**6.2**	**0.8**	**4.3**	**4.4**	**4.5**	**4.6**	**4.7**	**23.4**

In the 2027-2032 rate period, HOSSM expects capital expenditures to be $17.2M higher than the 2022-2026 actuals and forecast due to the increased volume of planned replacements.

[7] "Act/Fcst" refers to actual (2022-2025) and forecast (2026) amounts.
[8] "Act/Fcst" refers to actual (2022-2025) and forecast (2026) expenditures.

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T-SR-05	**STEEL STRUCTURE COATING PROGRAM**
Primary Trigger:	Cost Avoidance
OEB RRF Outcomes:	Customer Focus, Financial Performance

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	24.6	25.1	25.6	26.1	26.6	127.9

Summary:

This investment is to extend the service life of transmission line steel structures by coating them with a zinc-based product that protects the underlying carbon steel and preserves the steel structure integrity. The primary trigger of the investment is cost avoidance. The ongoing investment in steel structure coating is expected to extend the assets' service life, reducing overall lifecycle cost to manage steel structures by preventing higher capital expenditures in the future for costly steel member or complete structure replacement.

During the 2023-2027 period, Hydro One planned to coat 500 steel structures per year. Due to the reprioritization of investments as described in TSP Section 2.9, Hydro One expects to complete approximately 168 structures per year during that period.

Over the 2028-2032 planning period, Hydro One plans to address approximately 500 structures per year. The proposed pacing is consistent with historical planned pacing and reflects Hydro One's established approach to managing steel structure condition. This pacing balances outage requirements and budget considerations, while enabling the efficient and sustained execution of the program. Maintaining this established pace supports the ongoing mitigation of corrosion deterioration and preserves the long-term condition and reliability of the transmission system.

1.0 OVERVIEW

The Steel Structure Coating Program involves coating transmission line steel structures, thereby providing ongoing protection to the underlying carbon steel and preserving the steel structure integrity. Steel structures are manufactured from carbon steel and protected by hot dip galvanization (HDG), which is a zinc-based product used to protect the steel from corrosion. As this galvanized layer corrodes over time, bare carbon steel will eventually be exposed to the atmosphere and corrodes at a higher rate than the galvanized layer. Corrosion erodes structural integrity, and the eventual outcome of structure corrosion is costly steel member or complete structure replacement. Through this program, Hydro One treats corroded transmission line structures by applying zinc-based coating which is an efficient and cost-effective approach to extend asset life.

Coating steel structures with zinc-based product provides ongoing protection to the underlying carbon steel, thereby preserving the steel structure integrity. Structure coating does not, and is not intended to, prevent immediate structure failures. The rate of failure for structures is dependent on the condition of the structures and the impact of adverse environmental factors such as wind and ice, which are not predictable. However, if the corroded structures are not recoated prior to corrosion setting into the carbon steel layer, the steel structure will begin to lose structural strength and the only remaining mitigation option would be member replacement or even complete structure replacement.

The investment is a highly cost-effective program that considers repair versus replace options. In this case, repairing the asset by coating extends asset service life and is the preferred option. The coating of 500 corroded steel towers per year represents the appropriate pacing to achieve the economic benefit, aligning with historical pacing and accounting for outage constraints.

2.0 INVESTMENT NEED

Steel structures elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components. These structures have various designs, sizes and configurations and support transmission circuits from 115kV to 500kV.

As described above, steel structures are initially manufactured from carbon steel and protected by HDG, which consists of a zinc-based layer that protects the steel from corrosion. The zinc layer deteriorates due to corrosion over time. Based on studies conducted by corrosion experts, such as Electric Power Research Institute (EPRI), the service life of steel structures is primarily dependent on the condition of its HDG. Once a structure has lost the galvanizing protection from its HDG, the carbon steel will be exposed to the environment and the corrosion rate of the structure accelerates significantly, by a factor of eight to ten.

When the corrosion sets into the carbon steel layer, the steel structure begins to lose structural strength and the only solution may be partial or complete replacement of the tower. When structural strength diminishes below design strength, the integrity and capacity of the structure are compromised and a failure may occur under certain weather loading conditions.

Figure 1 and 2 illustrate heavy pitting corrosion of steel transmission towers in the Sarnia region, which required complete replacement.

Figures 1 and 2: Steel Structures in the Sarnia area exhibiting heavy pitting corrosion

Recoating the structure with a zinc-based product provides ongoing protection to the underlying carbon steel and preserves the integrity of the tower. Recoating effectively extends the service life of the steel structure and helps avoid the far more expensive alternative of replacing individual steel members, or, in severe cases, the entire tower. Replacement activities involve substantially higher material and labour costs and introduce greater operational complexity, longer outages, and significant logistical challenges. In contrast, recoating offers a cost-efficient, lower-disruption solution that maintains asset reliability while minimizing lifecycle expenditures.

Consistent with ISO 9223:2012, the province of Ontario is divided into four corrosion zones ranging from C2 to C5 (Figure 3). Each of these corrosion zones has a range of corrosion rates which can be used to estimate the service life of HDG steel based on its location.

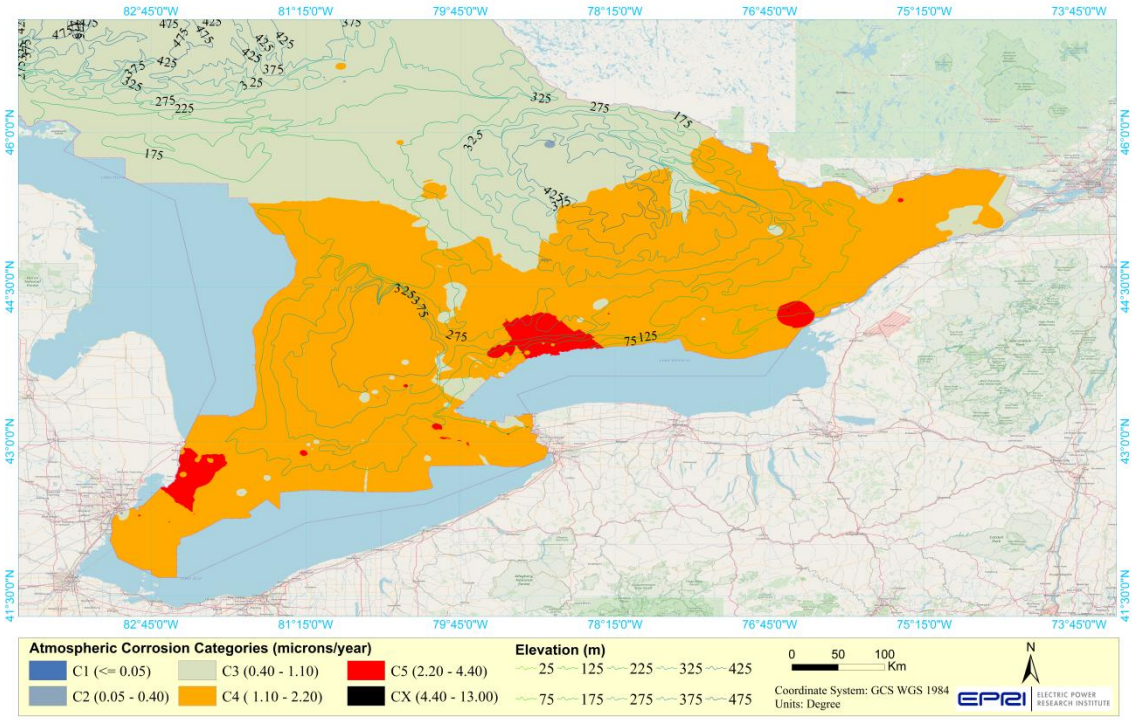

Figure 3: Corrosion zones in Ontario, courtesy of EPRI, 2017

C2 and C3 zones are defined as light corrosion zones, and the towers will generally be protected and maintained in good condition for a minimum of 115 years without requiring coating. Based on Hydro One asset records, there are approximately 10,400 steel structures in these light corrosion zones. None of the structures in the light corrosion zones are older than 115 years, and there are no immediate tower coating needs for structures within these zones.

C4 and C5 zones are defined as heavy corrosion zones which have high and very high corrosion rates. Based on Hydro One asset records, there are approximately 38,800 steel structures in the heavy corrosion zones. A prior study analyzed the structures located in the C5 zone and found that the structures in the C5 zone will, on average, lose their protective zinc coating 45 years after installation. Furthermore, they are expected to lose 10% of their metal over the following 30 years. At this stage, structures are no longer able to withstand their original design loads and either a major refurbishment or complete tower replacement is required. Applying these results to Hydro One's steel tower population, the study indicated that a significant portion of towers located in high and very high corrosion

zones is in need of coating to arrest further deterioration and prevent eventual replacements.

Based on condition data, there are approximately 10,700 poor condition steel structures in the C4 and C5 zones beyond the 45-year threshold, after which structures are expected to have lost their protective zinc coating, and experience corrosion on the HDG and, potentially, on the bare steel layer. These structures require recoating to extend their service life.

3.0 INVESTMENT DESCRIPTION

Hydro One plans to continue coating 500 steel towers per year, for a total of 2,500 structures or 23% of the poor condition steel structures in C4 and C5 over the 2028-2032 rate period. The structures will be coated with a zinc-based product thereby protecting the underlying carbon steel layer from corrosion and preserving the steel structure integrity.

During the 2023-2027 period, Hydro One planned to coat 500 steel structures per year. As described in TSP Section 2.9, Hydro One was required to reprioritize capital expenditures due to increasing demand for non-discretionary and externally-driven investments, coupled with significant cost escalation. Based on Actuals and Forecast for the 2023-2027 period, Hydro One expects to complete approximately 168 structures per year under this program.

Further cost pressures arose in 2023 from a combination of outage constraints, which resulted in extra tower climbs across multiple outages to complete the coating work and a higher-than-expected proportion of double-circuit towers. Both factors increased the labour hours needed to complete the work.

Over the 2028-2032 period, Hydro One plans to coat 500 steel structures each year, totaling 2,500. The proposed pacing is consistent with historical planned pacing and reflects Hydro One's established approach to managing steel structure condition. This pacing balances outage requirements and budget considerations, while enabling the efficient and sustained execution of the program. Maintaining this established pace

supports the ongoing mitigation of corrosion deterioration and preserves the long-term condition and reliability of the transmission system.

The investment's steel structure coating levels for the 2023-2032 period are summarized in Table 1.

Table 1 - Steel Structure Coating Program

Zone	Component	Plan[1] 23-27	Act/Fcst[2] 23-27	Total 28-32
Hydro One	Steel Structures	2,389	841	2,500
	% of Fleet (%)	4.7	1.7	4.9

4.0 OUTCOMES

As a result of the investment, Hydro One will minimize the lifecycle cost of managing steel structures within the transmission system. Coating steel structures before they lose their zinc protective layer prolongs their life and prevents higher capital expenditures in the future.

4.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 2 - Outcomes Summary

Customer Focus	• This investment will maintain the long-term reliability of the system by optimizing investment costs today and provide improved reliability and lower costs in the future.
Financial Performance	• Defer capital replacement costs by coating transmission line steel structures to preserve structural strength and extend service life.

[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 EXPENDITURE PLAN

Table 3 summarizes Hydro One's planned and actual/forecast capital expenditures for the 2023-2027 rate period and the forecast 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 28-32
Gross Capital Expenditures	100.0	42.8	24.6	25.1	25.6	26.1	26.6	127.9
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	100.0	42.8	24.6	25.1	25.6	26.1	26.6	127.9

Over the 2023-2027 rate period, Hydro One expects actual and forecast expenditures to be $57.2M lower than Plan due to reprioritization of investments and due to the sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110) as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Further cost pressures arose in 2023 due to a combination of outage constraints requiring extra tower climbs across multiple outages to complete the coating work and a higher-than-expected proportion of double-circuit towers, both of which require additional labour hours to complete the work.

In the 2028-2032 period, Hydro One expects expenditures to be $85.1M higher than the 2023-2027 actual and forecast, primarily to return work program volumes to historical planned levels combined with inflationary pressures as described above.

The factors influencing the cost of the investment include:

[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.

- Structure type/size – Depending on the voltage of the line, the structures will be different sizes. As the voltage increases, so does the size of the structure. Structure type also impacts the cost, as dead-end towers are bigger than suspension and will require more labour hours and materials to coat;
- Location of the structure (whether it is easily accessible or in a remote area) – Accessibility is very important, as having to clear brush and build roads adds significant costs;
- Environmental restrictions (whether it is a sensitive area to access) – crossing an environmentally sensitive area requires time and money to be spent on permits; and
- Work bundling – it is less expensive to coat towers that are in the same area if some costs can be shared between them.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: REACTIVE COMPONENT SUSTAINMENT

The reactive replacement of poor condition steel structures involves reactively responding and replacing corroded steel structures that are in poor condition. This alternative was rejected because reactive management of transmission lines structures would lead to increased asset failures, resulting in elevated safety and reliability risks. Further, as steel structures deteriorate, the cost to perform demand emergency repairs would cause a high financial impact on the Company and its customers.

ALTERNATIVE 2: PLANNED STEEL STRUCTURE COATING (RECOMMENDED)

The planned coating of steel structures at the proposed pacing levels is the recommended option. Under this alternative, poor condition steel structures that are eligible for coating will be coated proactively, in order to maintain long-term reliability and provide economic benefit to customers by avoiding more costly replacement.

7.0 EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the investment include accessibility to the assets that can vary by season, availability of qualified resources, and line outage availability. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial program planning phase where all known risks are identified and mitigation plans are developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan aims to minimize the loss of supply to the customer (i.e., switching a customer to an alternative supply). Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages.

T-SR-06	TOWER FOUNDATION CLEAN/COAT & LIFE EXTENSION PROGRAM
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	20.5	20.9	21.3	21.7	22.1	106.5

Summary:

This Investment comprises two programs to refurbish tower foundations that are in poor condition and present an elevated risk of structural failure:

1. **Foundation Clean and Coat:** Cleaning and coating transmission line steel structure foundations.
2. **Foundation Life Extension**: Refurbishing transmission line steel structure foundations whose deteriorated condition presents an elevated risk of failure, including potential structure collapse.

The focus of this Investment is on deteriorated steel grillage footings and anchor systems. Because of their age, design, and material composition, these components are increasingly susceptible to corrosion, section loss, and other structural defects. Failure of a tower footing can compromise tower stability, creating significant public safety hazards and system reliability risk. By refurbishing or replacing these deteriorated foundations, this investment will restore the structural integrity of the affected structures, reduce safety risks to Hydro One personnel and the public, and enhance overall operational reliability.

Expenditures under this Investment are planned to increase over the 2028-2032 period largely driven by higher refurbishment rates required due to the following:

- 230kV towers built before 1950 are reaching or exceeding their 80-year expected service lives and must be addressed to prevent safety or reliability events.
- Continued asset deterioration and deferred work from prior years necessitate an accelerated replacement pace.

1.0 OVERVIEW

This investment comprises two programs:

i. **Foundation Clean and Coat**: Cleaning and coating transmission line steel structure foundations; and

ii. **Foundation Life Extension**: Refurbishing transmission line steel structure foundations whose deteriorated condition presents an elevated risk of failure, including potential structure collapse. A failed asset poses serious safety risk to Hydro One's employees and the public, particularly when structures are located in publicly accessible areas. In addition, foundation failures create reliability risks that may result in customer outages.

As part of this investment, Hydro One conducts condition assessments of steel grillage footings to determine whether coating or minor refurbishment can be applied to extend the foundation's service life. Where severe corrosion has resulted in material loss, the foundation is identified as a candidate for major refurbishment.

Over the 2028-2032 period, the proposed investment will:

- Clean and coat approximately 1,080 towers with grillage footings per year, and
- Refurbish approximately 90 tower footings in deteriorated or damaged condition per year.

The proposed pace of this investment is the most prudent approach to sustaining transmission line steel structure foundations and to maintaining the safe, reliable performance of these assets and Hydro One's transmission system.

2.0 INVESTMENT NEED

Transmission line structure foundations support and anchor transmission structures to the ground and enable the structures to withstand the dead weight of the structure, attached line components and weather-related external forces such as wind and ice. Hydro One's transmission system primarily uses two types of foundations: cast-in-place concrete and steel grillage. As described in TSP Section 2.2.4.3, Hydro One's system contains approximately 49,200 steel lattice structures, supported either by concrete or steel

foundations. Of these, roughly 32,500 foundations are steel grillage (i.e., buried steel), while the remaining 16,700 are cast-in-place concrete.

Beginning in the 1970s, Hydro One transitioned to concrete foundations to meet updated transmission line design criteria, improve construction efficiency, and enhance long-term asset durability. Concrete foundations also provide improved compliance with increasingly stringent environmental protection regulations.

Consistent with the approach outlined in Hydro One's last transmission application (EB-2021-0110), Hydro One continues to prioritize the treatment, refurbishment or replacement of steel grillage footings and anchors, which typically exhibit a higher incidence of corrosion due to their age and material characteristics. From the early 1900s through the 1960s, most lattice steel structures were constructed using grillage footings. Today, approximately 32,500 towers remain supported by steel grillage foundations, including about 3,300 guyed structures that rely on both the grillage and the associated anchors for stability.

Grillage footings and anchors are protected by a zinc-based galvanized coating designed to slow corrosion. However, coating life varies significantly depending on soil conditions and other environmental factors. Once the galvanized coating is depleted, the exposed bare steel begins to corrode at a much faster rate, accelerating metal loss and reducing the mechanical strength of the foundation.

Steel grillage foundations become increasingly susceptible to degradation once they reach 50 years of age. As the majority of Hydro One's grillage foundations were constructed prior to 1970 and are now more than 50 years old, comprehensive assessment of these assets is required to identify corrosion, evaluate structural capacity, and determine appropriate remediation through coating, minor refurbishment, or major refurbishment.

The need for this investment is driven by the type of foundation and the consequences associated with an asset failure. Field inspections are used to identify foundations where

severe corrosion has resulted in significant structural deterioration or strength loss. When such conditions are observed, the foundation is classified as a candidate for major refurbishment.

A foundation failure can directly lead to structure collapse, which may result in system interruptions and pose serious safety risks to employees and the public. In addition, damaged or failing foundations can lead to high-cost corrective work, including the potential need to replace the entire transmission structure if deterioration is not addressed in time.

Figures 1 and 2 below illustrate examples of damaged grillage footings that resulted in tower leaning. In these cases, the towers eventually required full replacement due to the extent of the damage. Figure 3 shows heavily corroded footings and steel members at ground level, conditions that triggered a major footing refurbishment.

Figure 1: Towers Sitting in Water Causes the Foundations to Corrode, Leading to Towers Leaning (Circuit D2L, Near North Bay, ON)

Figure 2: Buckled Legs and Tower Leaning (Circuit M80B, Minden, ON)

Figure 3: Leg and Diagonals are Corroded Through, Necessitating Costly Refurbishment (Circuit D2L near Crystal Fall SS)

3.0 INVESTMENT DESCRIPTION

This investment comprises two programs: (i) Foundation Clean and Coat, and (ii) Foundation Life Extension.

The first program, Foundation Clean and Coat, is designed to inspect, clean, and coat the steel grillage footings buried underground. The objective of this program is to restore

depleted corrosion protection and extend the service life of these foundations. Through this program, Hydro One evaluates the condition of each tower footing and determines whether it should be coated immediately or scheduled for future refurbishment under the second program included in this investment. The decision to coat or refurbish is based on the severity of corrosion and the complexity of the required corrective work.

If no metal loss is observed during the Foundation Clean and Coat inspection, the footings are re-coated to establish corrosion protection and extend their service life. If metal loss is visible, the affected footings are scheduled for refurbishment or, where necessary, full replacement.

Over the 2028-2032 planning period, Hydro One plans to clean and coat approximately 1,080 towers with grillage footings per year. This execution pace increases relative to the historic and bridge period in order to address the 1,650 high-risk 230kV towers built before 1950, while maintaining sufficient capacity to support upcoming line refurbishment projects. The program will also address towers in line sections that are planned for refurbishment in the near-term, as well as a smaller proportion of towers with deteriorated foundations as identified through regular patrols. Hydro One prioritizes investments in steel structures and foundations based on line voltage, structure type, and the geographic location of the transmission lines. A summary of the planned clean and coat activities for 2023-2027 and 2028-2032 periods is provided in Table 1.

Table 1 - Foundation Clean and Coat Program

Zone	Component	Plan 23-27[1]	Act/Fcst 23-27[2]	Total 28-32
Hydro One	Tower (Unit)	3,510	4,200	5,400
	% of Fleet (%)	10.8	12.9	16.6

As shown in Table 1, Hydro One has increased the number of units addressed under this program over the 2023-2027 period relative to planned levels. This increase was mainly

[1] "Plan" refers to work volumes planned for the 2023-2027 period to reflect 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) amounts.

due to Hydro One bundling work on adjacent circuits to improve cost efficiency. The circuits addressed during the historic and bridge period were associated with upcoming projects. By bundling Foundation Clean and Coat work on these circuits, Hydro One was able to reduce costs and mitigate greater risks. In particular, Hydro One focused its work under this program on the Northern region in 2024 due to the condition of the assets in that region. In 2025, more structures were completed in the Chats Fall corridor than initially forecast in order to accommodate upcoming line refurbishment projects.

The second program, Foundation Life Extension, refurbishes steel grillage footings and anchors that exhibit advanced deterioration. This program targets foundations with heavy corrosion, material loss, and damaged or missing steel members, with the objective of restoring their structural integrity and load-carrying capacity.

Over the 2028-2032 period, Hydro One plans to refurbish approximately 90 towers per year. As shown in Table 2 below, the planned pace of this program is consistent with the average number of units completed over the last five years. The specific assets addressed under the program will be prioritized based on multiple factors, including circuit criticality, structure type, geographic location, and the severity of corrosion or physical damage. A summary of the planned refurbishment activities for the 2023-2027 and 2028–2032 periods is summarized in Table 2.

Table 2 - Foundation Life Extension Program

Zone	Component	Plan 23-27[3]	Act/Fcst 23-27[4]	Total 28-32
Hydro One	Towers (Unit)	375	453	450
	% of Fleet (%)	1.2	1.4	1.4

Over the 2023-2027 period, Hydro One increased refurbishment activities under the Foundation Life Extension Program in coordination with the expanded scope of the Foundation Clean and Coat program.

[3] "Plan" refers to work volumes planned for the 2023-2027 period to reflect 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 Actuals (2023-2025) and Forecast (2026-2027) amounts.

4.0 OUTCOMES

4.1 OEB RRF OUTCOMES

The objectives of this investment are to maintain transmission system reliability and mitigate employee and public safety risks by proactively addressing the condition of aging steel grillage foundations. Over the 2028-2032 planning period, Hydro One will:

- Clean and coat approximately 5,400 grillage footings; and
- Refurbish approximately 450 grillage footings.

These activities are intended to extend asset service life, reduce the likelihood of foundation and structure failures, and avoid more costly corrective actions in the future.

Table 3 presents the anticipated benefits of the proposed investment, aligned with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF).

Table 3 - Outcomes Summary

Customer Focus	• Reduce public safety risk associated with steel tower failures • Maintain customer reliability by restoring any depleted coating protection and extending the foundations' service life.
Operational Effectiveness	• Maintain system reliability by restoring any depleted coating protection and extending the foundations' service life. • Proactive foundation assessment and restoration will reduce emergency restoration frequency.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence and the TSC to maintain the reliability and integrity of its transmission system.

5.0 EXPENDITURE PLAN

As described above, the investment is required to mitigate the safety and reliability risks associated with poor condition tower foundations. Table 4 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 planning period. Costs for the Investment are based on historic expenditures.

Table 4 - Hydro One – Investment Expenditures[5]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	20.8	21.2	21.6	22.0	22.4	107.9
Less Removals	0.3	0.3	0.3	0.3	0.3	1.4
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**20.5**	**20.9**	**21.3**	**21.7**	**22.1**	**106.5**

The cost of the proposed investment is influenced by several key factors, including:

- Structure type and size: Structure size varies by line voltage. Higher-voltage transmission lines require larger structures and correspondingly larger foundations, resulting in increased material, labour, and equipment costs.

- Structure location and accessibility: Costs are significantly affected by the accessibility of the site. Remote, swampy, or otherwise difficult-to-access locations may require vegetation clearing, temporary or permanent access roads, or specialized access methods. In some cases, work can only be performed under frozen ground conditions, which can further increase scheduling and cost constraints.

- Environmental restrictions: Structures located within or near environmentally sensitive areas may require additional environmental studies, permitting, and mitigation measures. These requirements can increase both the duration and cost of the work.

- Work bundling and geographic proximity: Grouping work on towers located within the same geographic area improves efficiency, reduces mobilization and demobilization costs, and lowers overall unit costs.

- Extent and severity of damage: The level of deterioration directly influences work complexity. Heavily damaged foundations may require specialized construction methods, additional materials, and heavy equipment, resulting in higher costs.

[5] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 5 below summarizes Hydro One's planned, actual and forecast net capital expenditures for the 2023-2027 rate period and planned net capital expenditures for the 2028-2032 planning period. Amounts for the 2023-2027 Plan and Actual/Forecast have been adjusted to exclude investment expenditures that have been assigned to different ISDs for the 2028-2032 planning period compared to Hydro One's last transmission Application (EB-2021-0110), as further described in TSP Section 2.12.

Table 5 - Hydro One – Net Investment Expenditures

Description	Plan[6] 23-27	Act/Fcst[7] 23-27	Total 28-32
Foundation Clean and Coat	48.7	60.1	89.9
Foundation Life Extension	10.8	11.6	16.6
Total	59.5	71.7	106.5

Over the 2023-2027 rate period, Hydro One expects actual and forecast expenditures for the Foundation Clean and Coat Program to be $11.4M higher than Plan due to a higher volume of cleaned and coated foundations than planned resulting from bundling of work on adjacent circuits to optimize cost efficiency of the work. Additionally, in 2023, the mix of 115kV, 230kV and 500kV foundations addressed under this investment included a larger percentage of the significantly larger 500kV foundations compared to the preceding years. These larger towers require more labour hours to clean and coat. The mix of 115kV, 230kV and 500kV foundations returned to a more typical blend for 2024-2025.

In the 2028-2032 period, Hydro One expects capital expenditures for the Foundation Clean and Coat Program and the Life Extension Program to be $29.8M and $5.0M higher, respectively, than the 2023-2027 Actual and Forecast expenditures. The increase in both programs is primarily driven by the larger volume of towers planned to be addressed during the 2028-2032 planning period, as required to address a greater number of critical 230kV circuits with tower foundations that are beyond their 80 years of expected service life.

[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/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

Both programs have also been impacted by sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110) as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: REACTIVE FOUNDATION REPLACEMENT

This alternative involves a reactive approach, under which tower foundations and anchors are replaced only after failure has occurred. Hydro One rejects this alternative for the following reasons:

- A reactive approach to managing tower foundations and anchors would result in an increased frequency of asset failures, leading to heightened safety risks to employees and the public, as well as reduced system reliability.
- As foundations and anchors continue to deteriorate, the volume of emergency restorations and trouble calls would increase to levels that are operationally difficult to manage.
- Replacement of failed transmission tower foundations represents one of the most complex and operationally disruptive forms of asset intervention on the transmission system. These activities cannot typically be performed safely while the line remains energized, requiring multiple planned outages of extended duration. In many cases, outages must be staged to accommodate excavation, shoring, demolition of the existing foundation, installation of temporary structural support, and curing of new foundation materials before the tower can be reloaded. This significantly exceeds the duration and frequency of outages associated with proactive intervention.
- These prolonged and repeated outages materially impact both customer supply continuity and system operability. The affected circuits often perform a key role in

bulk power transfer or regional load supply, limiting the availability of operational alternatives during outage windows. This can increase system congestion, reduce transfer capability, and elevate operational risk during peak loading or adverse system conditions. As a result, foundation replacement not only disrupts service to end-use customers but also degrades overall transmission system resilience and flexibility during the outage period.

- Furthermore, emergency or reactive foundation replacement following structural failure introduces additional safety and reliability risks compared to planned preventive work. Unplanned failures may necessitate urgent response under less favourable site, weather, or system conditions, increasing exposure to worker safety hazards and the potential for cascading reliability impacts. Proactive interventions that preserve foundation integrity materially reduce the likelihood of these high-impact replacement scenarios, supporting compliance with transmission reliability obligations and minimizing customer disruption.

ALTERNATIVE 2: PLANNED FOUNDATION COATING AND REFURBISHMENT (RECOMMENDED)

This alternative involves the planned cleaning, coating, and refurbishment of steel structure foundations at a pace aligned with the optimal point in the foundation life cycle, when intervention is most effective in extending service life. This approach eliminates the deferred work of eligible steel structure foundations and reduces long-term planned and reactive replacement costs.

This alternative is preferred for the following reasons:

- Steel structure foundations in poor condition but still suitable for coating are addressed proactively, restoring corrosion protection and extending service life.
- Towers with damaged grillage foundations are refurbished before deterioration progresses to failure.
- Safety and reliability risks to the transmission system are mitigated through a balanced approach that considers asset condition, resource availability, outage coordination, and overall cost effectiveness.

7.0 EXECUTION RISK AND MITIGATION

The successful execution of this investment is subject to several risks, including seasonal access constraints, availability of qualified resources and specialized equipment, and outage availability on the transmission system. These risks are actively managed through comprehensive planning, scheduling, and coordination across Hydro One lines of business and external stakeholders.

During the initial program planning phase, Hydro One conducts a formal risk assessment workshop to identify known execution risks and develop appropriate mitigation strategies. This process ensures that risks are understood early and that controls are embedded into program delivery plans.

Access-related risks are mitigated through advance site planning and scheduling work during optimal seasonal windows, including frozen-ground conditions where required. Resource-related risks are addressed by early contractor engagement, workload forecasting, and alignment of internal and external resource availability with the planned work scope.

To manage outage constraints, Hydro One develops a coordinated outage planning strategy that aims to minimize customer impacts while enabling safe and efficient execution of foundation work. This includes, where feasible, transferring customers to alternative supply paths and aligning Hydro One supply outages with customers' planned maintenance outages. By synchronizing outage requirements and coordinating across stakeholders, Hydro One reduces the risk of schedule delays and limits the impact on system reliability.

Through these mitigation measures, Hydro One is able to manage execution risks effectively and support the timely, safe, and cost-efficient delivery of the proposed investment.

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T-SR-07	**TRANSMISSION LINE SHIELDWIRE REPLACEMENT**
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	39.0	39.8	40.6	41.4	42.2	203.1

Summary:

This investment addresses the ongoing replacement of shieldwire assets in deteriorated condition. The primary driver is the poor and worsening condition of existing shieldwire, which must be replaced to maintain system reliability and mitigate potential public safety risks.

Over the 2028-2032 planning period, Hydro One plans to increase expenditures on this investment, due to an increase in the volume of assets requiring replacement. Approximately 1,680 km or 5% of Hydro One's shieldwire is in poor condition, and continued asset deterioration and deferred work from prior years necessitate an accelerated replacement pace. The forecast cost of the investment also reflects the fact that Hydro One plans to replace an increased amount of deteriorated conventional shieldwire with Optical Ground Wire (OPGW), providing a pathway to support Hydro One's power system telecom services.

1.0 OVERVIEW

Transmission line shieldwire is a critical component of Hydro One's transmission system, providing essential lightning protection and grounding continuity for overhead lines. An example of transmission line shieldwire is presented in Figure 1.

The Transmission Line Shieldwire Replacement program replaces shieldwire in poor condition. If shieldwire in poor condition is not replaced in time, the likelihood of asset failure becomes very high. A broken or sagging shieldwire can make contact with the conductor, resulting in circuit outages, customer interruptions, and significant public and worker safety hazards, as fallen shieldwire may swing or drop to the ground. Work conducted under the program is prioritized based on condition assessments, helping ensure that the at-risk sections are addressed in a timely manner.

As described in TSP Section 2.2.4.6, Hydro One is now in a period in which a considerable portion of shieldwire on many transmission lines is reaching poor condition. To mitigate the associated reliability and safety risks, this investment targets the replacement of approximately 400 km of shieldwire per year from 2028 to 2032.

Under this Investment, Hydro One plans to replace an increasing proportion of deteriorated shieldwire with Optical Ground Wire (OPGW), an aluminum-alloy stranded shieldwire with a fibre-optic core to support telecommunications. Where a telecommunications path is required, replacing conventional shieldwire with OPGW serves a dual function: it protects conductors from lightning strikes, like a traditional shieldwire, while also providing a high capacity fibre-optic communication pathway that supports grid monitoring, SCADA, control, and other utility communication needs. Hydro One's telecommunications needs are further described in TSP Section 2.2.2.5 and ISDs T-SR-12 and T-SR-17. For clarity, this investment is complementary to and mutually exclusive from ISDs T-SR-12 and T-SR-17. This integration of power and telecommunications within a single cable allows Hydro One to improve the operation and reliability of the transmission system.

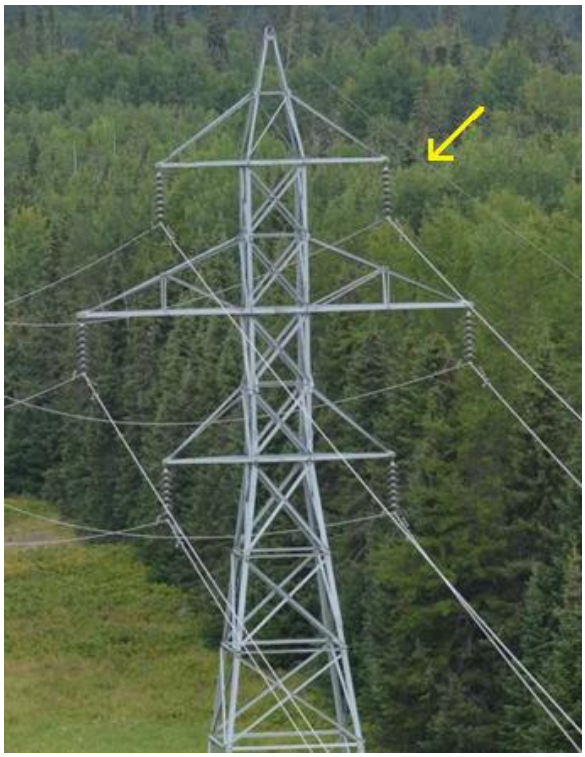

Figure 1: Transmission Line Shieldwire

2.0 INVESTMENT NEED

There are approximately 34,600 km of shieldwire strung above Hydro One's overhead transmission lines. Hydro One's network consists of the following five types of shieldwire:

i. Galvanized Steel;
ii. Aluminum Conductor Steel Reinforced (ACSR);
iii. Optical Ground Wire (OPGW);
iv. Copperweld; and
v. Alumoweld.

Shieldwire replacement is condition driven. Figure 2 below presents condition information for shieldwire currently installed on the Hydro One network. As discussed in TSP Section 2.2.4.6, condition assessments are used to verify if shieldwire is in poor condition, at which point it is scheduled for replacement.

Shieldwire assets that have minor deterioration are considered to be in fair condition and are scheduled for re-assessment at a later date. Shieldwire classified in good condition has either been assessed to be in good condition or has not yet reached the age at which shieldwire condition assessment begins. The “needs assessment” category refers to shieldwire that has reached an age requiring condition assessment / re-assessment.

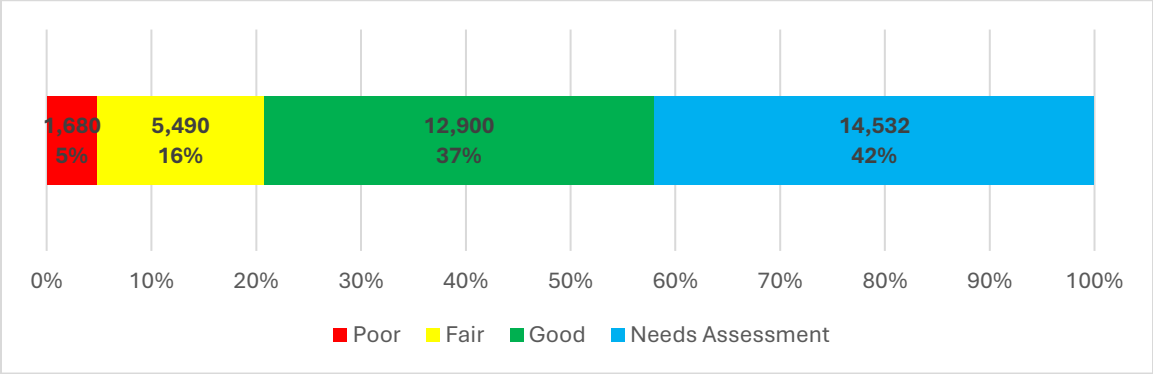

Figure 2: Condition of Hydro One Shieldwire Assets

As shown in Figure 2, a substantial volume of shieldwire (1,680 km) is currently in poor condition and requires replacement. In addition, approximately 14,500 km of shieldwire has reached an age where assessment is required; and a portion of this population is expected to have deteriorated to a state requiring replacement and will be assessed to be in poor condition. Further, as these assets continue to age, an increasing share of the shieldwire population that is currently rated in fair condition is also expected to decline, further expanding replacement requirements. Without sustained investment, the volume of shieldwire requiring replacement is expected to grow significantly over time.

Replacing deteriorated shieldwire is essential to sustaining both system reliability and public safety across the transmission network. Condition assessments have identified these assets as high-risk due to advanced deterioration, loss of mechanical strength, and the heightened likelihood of failure.

A failed shieldwire can fall onto energized conductors, triggering forced outages, equipment damage, and widespread reliability impacts for customers. The consequences

are even more severe in urban corridors, where a falling shieldwire poses a significant public safety hazard to pedestrians, roadways, and surrounding infrastructure.

Accordingly, Hydro One prioritizes shieldwire replacements based on asset condition, risk, and system impact. By advancing this investment, Hydro One will materially reduce outage risk, maintain compliance with safety obligations, and ensure continued delivery of reliable service to customers while mitigating avoidable public safety hazards.

Examples of shieldwire failure experienced at Hydro One can be found in Figures 3 to Figure 7 below.

Figure 3: 2016 Shieldwire Failure on K2

Figure 4: 2016 Shieldwire Failure on D10H

Figure 5: 2017 Shieldwire Failure on S22A

Figure 6: 2024 Shieldwire Failure on K2Z

Figure 7: 2026 Shieldwire Failure on X503E

3.0 INVESTMENT DESCRIPTION

The investment focuses on replacing galvanized steel, ACSR, and Copperweld shieldwire that is currently in poor condition according to the following:

- Aluminum-clad steel (Alumoweld) is the most recently adopted shieldwire type on the Hydro One system and is now the standard replacement for non-OPGW applications.

- Where a fibre-optic communication path is required, Hydro One installs OPGW. This consists of an Alumoweld and aluminum-alloy stranded shieldwire with a fibre-optic core to support telecommunications. In these circumstances, installing OPGW under this program provides additional benefits relative to discrete telecommunications investments.

- ACSR conductors are occasionally used as shieldwire in areas where fault current levels exceed the capability of conventional shieldwire materials. Historically, ACSR was installed in place of galvanized steel and today remains the preferred alternative to Alumoweld in high-fault-current environments.

- Copper-clad steel (Copperweld) is another shieldwire type found in limited numbers on the Hydro One network. Copperweld does not adequately withstand lightning strikes and is therefore being prioritized for replacement.

Galvanized steel remains the most common shieldwire type on the Hydro One transmission network; however, it is no longer installed due to well-known deficiencies associated with its zinc coating. Over time, the protective coating deteriorates, reducing mechanical strength and increasing the risk of failure. The average age of galvanized steel shieldwire is currently 60 years, which is above the 50-year expected service life. This type of shield wire currently comprises approximately 55% of the fleet.

Due to historical construction and demographic patterns, Hydro One is now in a period where the shieldwires on many overhead transmission line sections are in poor condition and the population of poor condition shieldwire continues to grow. In order to effectively manage these circuits and prevent shieldwire related outages, this investment targets the replacement of 400 km of shieldwire per year over the 2028 to 2032 period. The proposed pacing is higher than the historical average accomplishments for this investment by 195 km per year. The investment's replacement levels for the 2028 to 2032 period have been summarized in Table 1 below.

Table 1 - Shieldwire Replacement

Zone	Component	Plan 23-27[1]	Act/Fcst 23-27[2]	Forecast 28-32
Hydro One	Shieldwire (km)	1,481	1,023	2,000
	% of Fleet (%)	4.2	2.9	5.7

[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) amounts.

Hydro One expects to replace approximately 69% of the kilometers of shieldwire planned for replacement under this program in the 2023-2027 period. This is primarily due to the reprioritization of capital expenditures required to address increasing demand for non-discretionary and externally-driven investments, coupled with significant cost escalation, as described in TSP Section 2.9. Further detail on expenditures over the historic and bridge period, and the 2028-2032 forecast period are provided in Section 5.0 below.

The proposed pacing of this Investment is driven by three key factors:

1. **Current Population of Poor-Condition Shieldwire**

   Approximately 1,680 km of Hydro One's transmission shieldwire is currently in poor condition. Overall deterioration of the asset population continues to accelerate as the existing shieldwire ages, increasing both reliability and safety risks if replacement is deferred. Recent pre-construction testing has shown a more than 25% reduction in mechanical strength compared with test results from a decade ago. This measurable decline demonstrates an escalating rate of degradation and reinforces the need to accelerate replacement activities to prevent failures and associated system impacts.

2. **Deferred Work**

   The following challenges resulted in deferral of shieldwire replacement work during the 2023-2027 rate period:

   - Reprioritization of capital expenditures due to increasing demand for non-discretionary and externally-driven investments, coupled with significant cost escalation, which required scaling back annual work volume.
   - Execution constraints, including the cancellation of planned outages needed to complete shieldwire replacement work safely and efficiently.

   These factors have collectively slowed progress, resulting in a higher volume of assets requiring replacement today.

3. Increase in Assets Requiring Assessment or Reassessment

As shown in Figure 2, over 40% of the shieldwire fleet currently requires assessment or reassessment. As these evaluations proceed, the number of assets classified as "poor" will continue to grow due to ongoing deterioration. Proposed pacing reflects the expected growth in the poor condition population during the 2028-2032 rate period.

The proposed pace of replacement under this Program helps ensure that:

- Shieldwire already confirmed to be in poor condition is replaced promptly.
- Public and worker safety risks from potential wire failures are minimized.
- System reliability is maintained by preventing avoidable outages associated with shieldwire breakage.

The investment includes all design, procurement, field verification, installation and commissioning required to replace the poor condition shieldwire with new Alumoweld or OPGW, including the necessary dampers and associated attachment hardware.

4.0 OUTCOMES

Hydro One aims to achieve the following outcomes as a result of this investment:

- Maintain system and customer reliability by replacing poor condition shieldwire and mitigating outages caused by failing shieldwire.
- Reduce the likelihood of employee and public safety incidents related to falling shieldwire. The likelihood of such injuries occurring can be reduced if poor condition shieldwire is replaced.

4.1 OEB RRF OUTCOMES

Table 2 below presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 2 - Outcomes Summary

Customer Focus	• Reduce public safety risks associated with shieldwire failures. • Maintain customer reliability by replacing poor condition shieldwire.
Operational Effectiveness	• Maintain system reliability by replacing poor condition shieldwire. • Proactive shieldwire replacement will reduce emergency restoration frequency.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence and the TSC to maintain the reliability and integrity of its transmission system.

5.0 EXPENDITURE PLAN

As discussed above, this investment is required to mitigate the safety and reliability risks associated with poor condition shieldwire.

Table 3 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 rate period. Costs for the investment are based on historical replacement costs.

Table 3 - Hydro One – Investment Expenditures[3]

($M)	Plan[4] 23-27	Act/Fcst[5] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	71.6	97.5	42.4	43.3	44.1	45.0	45.9	220.7
Less Removals	5.7	7.7	3.4	3.5	3.5	3.6	3.7	17.7
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**65.9**	**89.8**	**39.0**	**39.8**	**40.6**	**41.4**	**42.2**	**203.1**

The replacement costs are influenced by structure type and accessibility. The factors influencing the cost of the investment include:

- Existing shieldwire condition – The cost varies depending on whether the old shieldwire has enough strength remaining to use it when pulling the new wire.

[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.

- New shieldwire type – The cost varies significantly depending on whether the new shieldwire is Alumoweld or OPGW, as described below.
- Structure size/type – Costs can vary depending on how many circuits are on the structure, how tall it is and how the shieldwire is attached.
- Location of the line (i.e., whether it is easily accessible or in a remote area) – Accessibility is very important, as having to clear brush and build roads adds significant costs.
- Environmental and real estate considerations (i.e., whether the location is a sensitive area to access) – Crossing an environmentally sensitive area requires time and money to be spent on permits.
- Work bundling – It is cheaper, per kilometer, to replace a longer line section than a shorter line section one because mobilization costs are reduced.

Over the 2023-2027 rate period, Hydro One expects actual and forecast expenditures to be $23.9M higher than Plan due to the increased use of OPGW to support power system telecom services. This trend is expected to continue to drive capital expenditures under this program in the 2028–2032 period, in addition to the increased volume of work planned under the program as outlined in Section 3.0. An additional factor causing an increase in forecast capital expenditures is higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period.

The proportion of shieldwire replacements using OPGW continues to grow due to the increasing need for reliable, Hydro One-owned fiber optic communication. Unacceptable reliability of leased services, their considerable expense and discontinuation of such services has made the Hydro One-owned OPGW installation more desirable. Further description of the increasing need for Hydro One-owned fiber optic communications is provided in TSP Section 2.2.2.5 and ISDs T-SR-12 and T-SR-17.

Using OPGW allows Hydro One to replace deteriorated shieldwire and enable future fibre-optic connectivity in a single construction effort, reducing long term incremental costs versus separate installations.

Compared to conventional shieldwire, OPGW installation typically costs three to four times as much. The differential is driven by:

- Increased material costs due to higher aluminum and aluminum alloy content and integrated fibre-optic components and more complex manufacturing;
- Additional installation complexity (e.g., specialized handling, stringing, clamping, deadending, splicing), increasing the time required to complete a section of shieldwire replacement; and
- Required tower peak modifications or reinforcements to support OPGW loads.

During the 2023-2027 rate period, less than two-thirds of shieldwire replacements used OPGW. In the 2028-2032 rate period, this proportion is expected to be three quarters, increasing the program cost.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

This approach involves the reactive replacement of poor condition shieldwire only after a failure has occurred. This approach would increase the frequency of asset failures and elevate safety and reliability risks for both workers and the public. Emergency replacements also necessitate ongoing reprioritization of planned work, resulting in inefficient deployment of resources and reduced productivity. Reactive failures would further prolong circuit outages because a transmission circuit cannot be safely re-energized until the damaged shieldwire has been fully restored. Unlike planned replacements, in which outages, materials, and crews can be coordinated in advance, reactive work requires emergency mobilization and often occurs under adverse or complex field conditions. Completing these repairs can take many hours or multiple days,

thereby extending circuit outages and increasing the likelihood of prolonged equipment and customer interruptions. This extended outage duration is inconsistent with maintaining reliable service and meeting system performance expectations.

ALTERNATIVE 2: PROACTIVE REPLACEMENT OF ALL POOR CONDITION SHIELDWIRE (RECOMMENDED)

This approach involves planning for the replacement of all shieldwire confirmed to be in poor condition and the shieldwire that is expected to reach poor condition during the 2028-2032 forecast period. Condition assessments conducted during the period will reveal additional sections of shieldwire that have reached poor condition and require replacement. This alternative will replace approximately 2,000 km of poor-condition shieldwire during the forecast period, consistent with the proposed replacement pace described above.

7.0 EXECUTION RISK AND MITIGATION

Implementation risks to the investment include outage restrictions and material lead time. These risks are mitigated through proactive planning and coordination well in advance of the investment's execution to ensure outage and material availability. For example, because required shieldwire lengths and sizes can vary greatly, Hydro One only stores small sections of shieldwire for emergency repair. All material required for planned replacements is ordered specifically for each project. Shieldwire and accessories can take between 6-12 months to order and receive, and will delay the planned replacement if not obtained in time. To reduce the likelihood of this delay occurring, replacement work is planned and material is ordered approximately one year in advance.

T-SR-08	TRANSMISSION LINE INSULATOR REPLACEMENT
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	72.8	74.3	75.7	77.3	78.8	378.9

Summary:

The Transmission Line Insulator Replacement investment replaces defective porcelain insulators on Hydro One's transmission system, primarily targeting those manufactured between 1950 and 1982. This investment is an ongoing program. In 2016, Hydro One retained the Electric Power Research Institute (EPRI) to assess the condition of these porcelain insulators and the assessment results obtained by EPRI support timely replacement. The rate of replacement for the 2028-2032 planning period has been adjusted since Hydro One's last transmission application (EB-2021-0110), and the range of targeted insulators has been expanded to include insulators manufactured in the 1950s because of recent failures. As part of this investment, Hydro One plans to replace the remaining identified defective insulators by 2032. Hydro One will also replace deteriorated polymer insulators.

During the prior rate period (2023-2027), Hydro One planned to replace defective insulators on 3,691 circuit-structure per year. Hydro One currently expects to replace insulators on 2,865 circuit-structures per year on average, due to the reprioritization of investments as described in TSP Section 2.9 as well as cancellation of outages. During the 2028-2032 planning period, Hydro One plans to replace insulators on 3,400 circuit-structures per year.

1.0 OVERVIEW

The Transmission Lines Insulator Replacement investment primarily involves the replacement of defective porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1950 and 1982. Before the early 1980s, these defective insulators were historically used province-wide in Hydro One's transmission system. The defect associated with porcelain insulators results in two failure modes: (i) mechanical failure, which cause the conductor to fall on the ground; and (ii) electrical failure which triggers a forced outage, sometimes for a prolonged period of time. These types of failures pose significant safety and system reliability concerns.

In 2016 Hydro One retained a third-party expert, the Electric Power Research Institute (EPRI), to assess the condition of defective COB and CP porcelain insulators to assist Hydro One in determining the pacing of porcelain insulator replacement.[1] EPRI completed laboratory testing which provided evidence to support taking timely action to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation made by EPRI is that the population of defective COB and CP insulators installed between 1965 and 1982 be removed from service as soon as practically possible.

EPRI testing of pre-1965 insulators concluded that some 1950s units performed satisfactorily, while insulators manufactured in 1960 and later showed poor results. Based on this, Hydro One previously set the replacement range to 1960-1982 to target known defective COB/CP insulators. Subsequent evidence showed this date range was too narrow for the population of Hydro One insulators. EPRI conducted a further study in 2017, which tested 15-kip insulators[2] from 1952 and 1963 and found their performance comparable to 1970s units, which raised a concern that the earlier assumption of acceptable 1950s performance (which was based on 11-kip units) did not represent the broader population, as most Hydro One insulators are 15-kip units. This concern has been confirmed by recent failures involving insulators manufactured in 1950, 1953, 1956, and 1958.

[1] The reports were submitted in EB-2016-0160 Interrogatory I-9-6 Attachment 1 and EB-2019-0082 TSP Section 1.4 Attachment 12.
[2] Insulators and other load-bearing equipment are categorized based on their mechanical strength ratings. A kip is a unit of force used in the imperial system and is equal to 1,000 pounds-force.

Considering both the expanded EPRI testing and field failures, Hydro One has extended the replacement range to all insulators manufactured from 1950 through 1982, ensuring the removal of all potentially defective COB/CP units from the transmission system.

This program will also address the replacement of deteriorated polymer insulators. Polymer insulators in dead-end configurations are known to fail due to their exposure to high electric-field gradients that cause silicone degradation. The degradation exposes the fiberglass rod that holds the insulator together to moisture, which causes rapid deterioration leading to failure.

Hydro One retained EPRI to perform a detailed condition assessment of polymer insulators to assist Hydro One in determining the need and pacing of polymer insulator replacement.[3] EPRI completed laboratory testing and provided technical data showing that condition varies based on voltage, manufacturer and use of corona rings. The results of this study indicate that Hydro One should plan to remove certain insulators which show extensive degradation from service as soon as possible due to high risk of failure. Other types of insulators should continue to be assessed periodically for signs and degree of degradation. As part of this investment, Hydro One will be replacing the deteriorated polymer insulators.

Program pacing is mainly influenced by the number of remaining defective porcelain insulators. As part of this investment, Hydro One plans to replace the remaining identified defective insulators by 2032. The rate of the replacement will be approximately 3,400 circuit-structures per year for the remaining duration of the program to catch up on the deferred work from the 2023-2027 prior rate period and to address the additional pool of defective insulators from the 1950s.

[3] EB-2019-0082 TSP Section 1.4 Attachment 11, EPRI Polymer Insulator Population Assessment.

2.0 INVESTMENT NEED

Transmission line insulators are an integral component of the transmission system. Transmission line insulators are required to perform two basic functions. They provide mechanical support for overhead conductors and electrical isolation between the energized conductors they support and the grounded towers to which they are attached. A typical transmission line insulator string is shown in Figure 1 while an individual insulating unit (i.e., skirt, disk, shell) is shown in Figure 2.

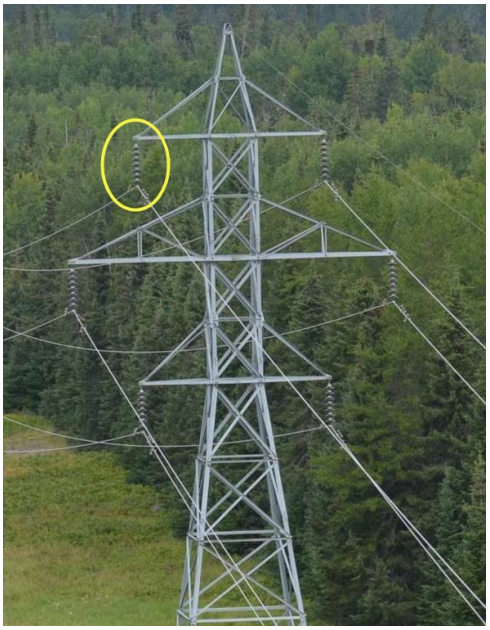

Figure 1: Transmission Line Insulator String

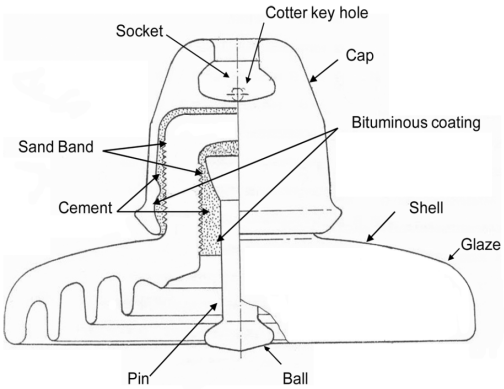

Figure 2: Transmission Line Insulator Unit

There are approximately 489,000 insulator strings[4] in Hydro One's overhead transmission network on 121,418 circuit structures. As described in TSP Section 2.2.4.4, Hydro One has three types of transmission line insulators in its fleet: porcelain, glass and polymer. The demographic of insulators by material type are shown in Table 1 below.

Table 1 - Quantity of Circuit Structures by Insulator Type

Insulator Type	Circuit Structure Quantity
Porcelain	60,233
Glass	51,134
Polymer	10,051
Total	121,418

2.1 DEFECTIVE PORCELAIN INSULATORS

Age demographics are not a driving factor for the replacement of porcelain or glass insulators since these types of insulators are generally expected to last as long as the transmission lines they serve. However, porcelain insulators manufactured by COB and CP between 1950 and 1982 suffer from a phenomenon known as cement expansion or cement growth, as shown in Figure 3 below. It is recognized throughout the electricity industry that both the electrical and mechanical characteristics of line insulators manufactured between the 1950s and early 1980s by COB and CP deteriorate faster than other comparable insulators due to cement expansion.

Figure 3: Porcelain Insulator Unit Affected by Cement Expansion

[4] An insulator string is a series of insulators strung together. The number of insulators that comprise an insulator string is variable.

Porcelain transmission line insulators are specified in terms of their combined mechanical and electrical (M&E) strengths. For example, an insulator with an M&E rating of 36 kips (1 kip = 1,000 pounds-force) is designed to withstand an applied tensile load up to 36 kips without mechanical or electrical failure. With respect to cement expansion, mechanical failure is defined as a physical breakage of the insulator while electrical failure is defined as cracking of the insulator's porcelain body or cement in the area between the cap and the pin which results in a significant reduction of the insulator's dielectric strength.

Cement expansion creates radial cracks in the cement and porcelain shell resulting in two possible failure modes:

- **Mechanical failure** – As described above, a physical breakage of the insulator may result in a conductor falling to the ground, posing an extremely significant risk to public and employee safety. For example, in March 2015, an insulator on circuit V76R mechanically failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. Similarly, in January 2017, an insulator on circuit HL3 mechanically failed causing the conductor to fall over a roadway in Hamilton. Another example occurred in 2019 on 500kV circuit D501P in Timmins, Ontario with a failed 1962 porcelain insulator and in this case the conductor did not drop as the idler string held on until crews arrived. In February 2024, an insulator (1958 vintage) on circuit H24S mechanically failed causing the conductor to fall near the ground; the dropped conductor remained energized for a prolonged period until being reported by a member of the public. A few more recent examples of major insulator failures causing conductor drops include 115kV circuits K3D (1956) and R1LB (1950) in 2025, and 115kV circuit A7C (1953) in 2026, with the failed insulator vintages as indicated in the brackets. Photos of these failures are provided in Figure 4 through Figure 10 below.
- **Electrical failure** – Cracks in the porcelain reduce the insulating properties of the material. This failure typically results in sustained customer outages. Failed insulators normally result in sustained forced outages due to the permanent electrical fault they create. Repair time can be significant, averaging 37 hours per outage, depending on the location and severity of the failure.

Figure 4: V76R Insulator Failure in March 2015

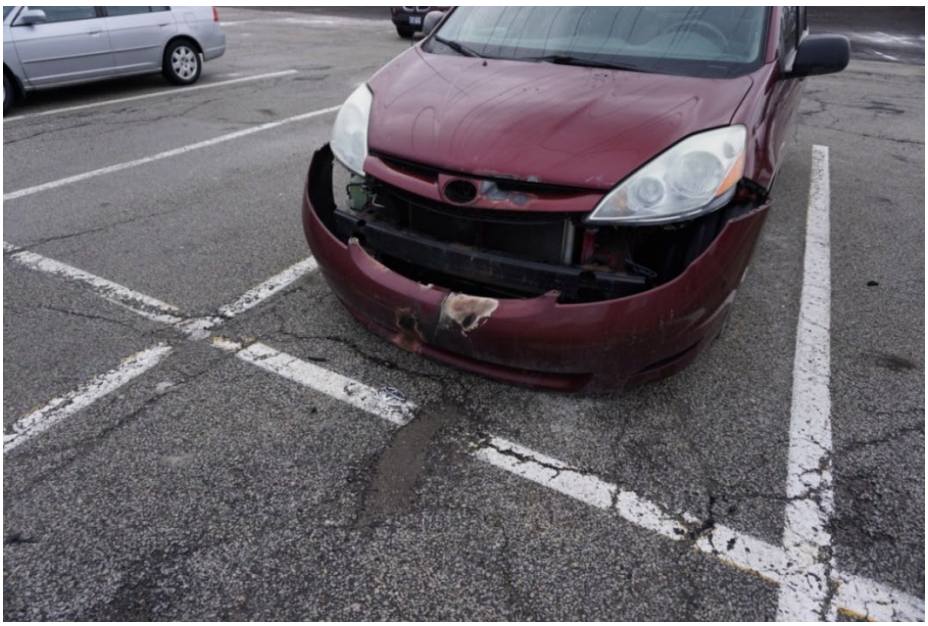

Figure 5: Damage Caused by V76R Insulator Failure in March 2015

Figure 6: HL3 Insulator Failure in January 2017

Figure 7: H24S Insulator Failure in Feb 2024

Figure 8: K3D Insulator Failure in July 2025

Figure 9: R1LB Insulator Failure in September 2025

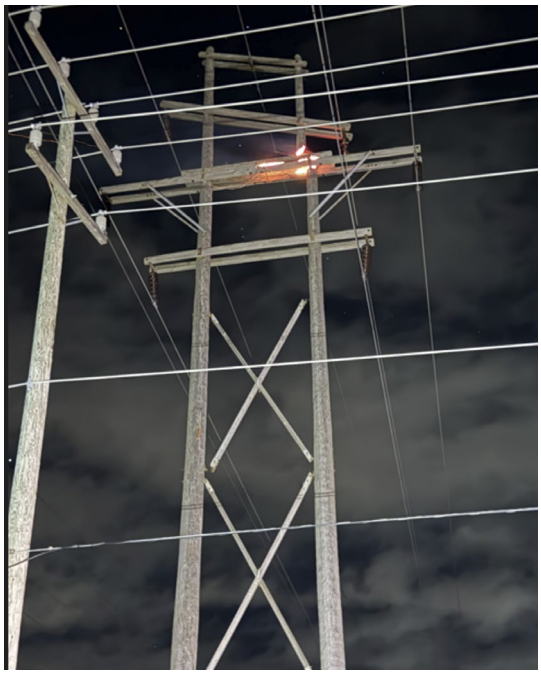

Figure 10: A7C Insulator Failure in January 2026

The porcelain insulators manufactured by COB and CP were used province-wide in Hydro One's transmission system before the early 1980s. There were approximately 49,800 circuit structures with defective porcelain insulators. To date approximately 31,300 COB and CP insulators have been replaced. A breakdown of the defective population in relation to the total insulator population as of 2025 year-end can be seen in Figure 11 below.

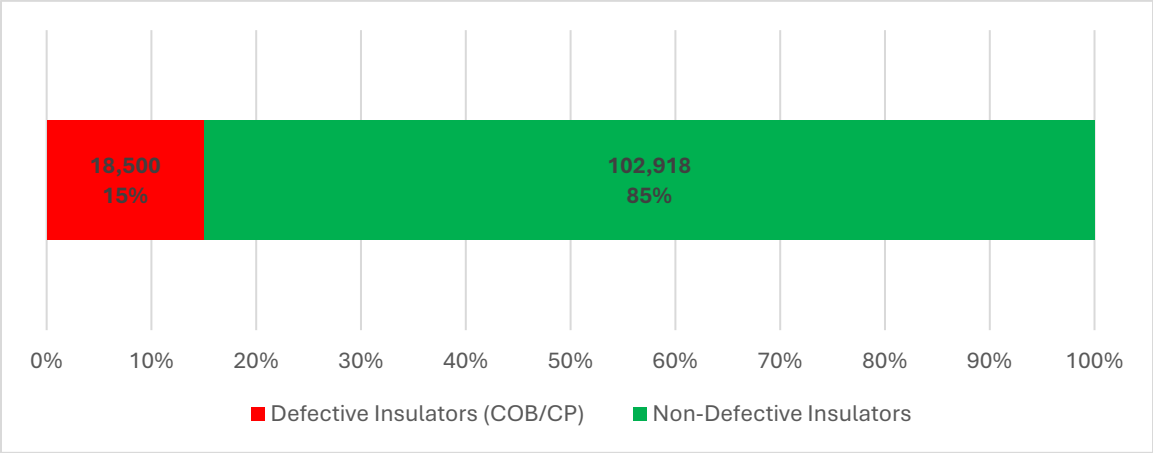

Figure 11: Hydro One Insulator Fleet Condition Status (2025 YE)[5]

[5] Hydro One is in the process of identifying the number of poor condition polymer insulators.

Figure 12 below illustrates the number of COB and CP failures over the past ten years showing a downward trend after the peak in 2019. The failures are expected to continue to occur until the defective insulators are all replaced, which can impact public safety, system performance and customer reliability. As noted above, electrical failures typically result in outages requiring significant repair time.

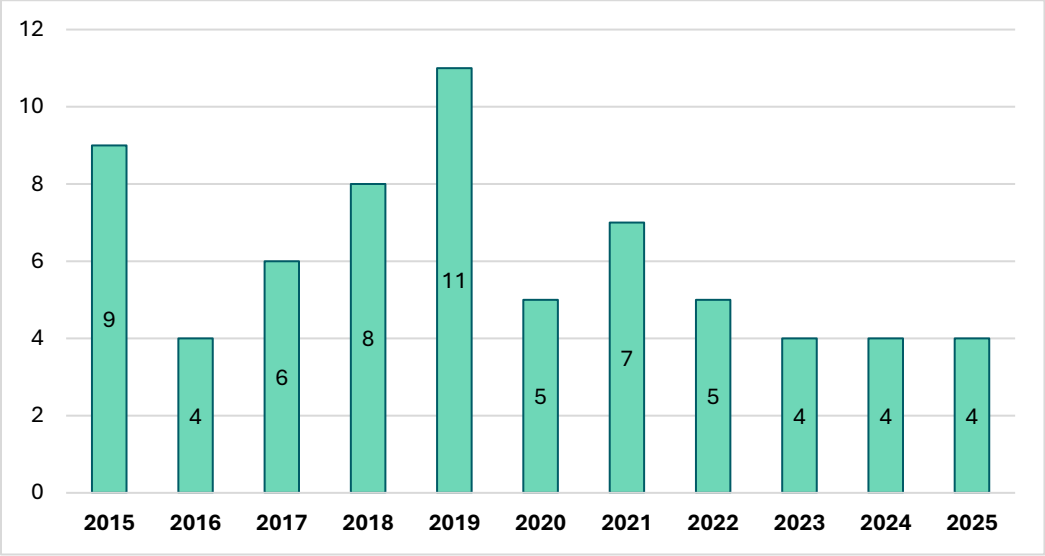

Figure 12: Frequency of COB/CP Insulator Failures

As discussed above, EPRI conducted laboratory testing on COB and CP porcelain insulators in two phases to assess their condition and assist Hydro One in determining the pacing of porcelain insulator replacement.

Phase one was completed in 2016[6] and included testing of 299 insulators removed from a combination of dead-end and suspension strings installed in publicly-accessible (critical) locations. Phase one testing was intended to provide a rapid assessment of the condition of the in-service insulators in question. The phase one results supported the timely replacement of COB and CP insulators manufactured between 1965 and 1982. Based on the phase one results, Hydro One significantly increased the insulator replacement rate

[6] EB-2016-0160 Interrogatory I-9-6 Attachment 1: EPRI - Results and Analysis of Phase 1 Insulator Tests Performed in Support of Hydro One Insulator Replacement Program.

beginning in 2016, compared to pre-2016 levels, and prioritized the replacement of insulators in publicly accessible (critical) locations.

A large proportion of the insulators tested during phase one (37%) failed electrically or mechanically at loads below their rated M&E strength. There was a significant number of punctured insulators and the test data showed a large variation in the loads causing failure, which would not be expected from a healthy insulator population.

The condition of the Hydro One insulators was assessed through comparison against EPRI and public domain test data. This comparison data was obtained through testing similar vintage insulators, which had been in service for a comparable duration under similar field conditions. The performance of the Hydro One and the comparison insulators was also evaluated against current and historical requirements for new insulators. The test results presented an initial snapshot of the condition of the population of defective insulators in-service on Hydro One's transmission system.

Phase two of the testing was performed in 2017.[7] Those tests were carried out on 591 insulators. The intent of the phase two tests was to supplement the phase one data and to provide data on the rate of deterioration of the insulator population. The results of this analysis showed that:

- a large number of the tested insulators exhibited porcelain cracking after M&E testing;
- the insulators tended to puncture (crack) during Thermal Mechanical Cycling (TMC);
- the insulators are highly susceptible to electrical puncture (i.e., a disruptive discharge passing through the solid insulating material of an insulator) under steep transient voltages (e.g., lightning);
- TMC drastically decreases the ability of the insulators to withstand electrical puncture; and
- a significant number of insulators separated mechanically during TMC.

[7] EB-2019-0082 TSP Section 1.4 Attachment 12, EPRI - Phase 2: CP/COB Porcelain Insulator Population Assessment

These results suggest that the number of in-service punctured units will increase as the insulators experience significant mechanical loading events. When a string containing electrically punctured insulators undergoes a flashover due to lightning, contamination, or snow and ice bridging, there is a high likelihood that the ensuing power arc will pass through the punctured unit internally travelling from cap to pin, causing significant heating and pressure buildup, which can cause the cap and pin to separate and the conductor to drop. The greater the number of punctured insulators found in the string, the higher the probability of string flashover and string separation. The conductor drops recently experienced on Hydro One's porcelain insulated transmission system failed due to this mechanism.

Insulators which are not punctured but have suffered deterioration in mechanical strength do not exhibit this behavior. If a string contains mechanically compromised units, the insulators will fail if the maximum applied load exceeds the units' remaining mechanical strength.

The phase one and two analyses provided strong evidence supporting replacement of defective porcelain insulators to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation provided by EPRI is that the identified population of COB and CP insulators should be removed from service as soon as practically possible.

2.2 DETERIORATED POLYMER INSULATORS

Hydro One uses polymer insulators on the 115kV and 230kV transmission system. Polymer insulators have an expected service life (ESL) of 30 years and, due to their material properties, degrade with age. First-generation polymers installed in the mid-1980s are beyond their ESL and need to be replaced.[8] First-generation polymers are more prone to failure compared to more recent generations. When older polymer insulators were designed and manufactured, the long-term effects of electric fields on them were not well understood and unexpected degradation has been observed. Newer

[8] Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions.

generation polymer insulators use modified designs and refined manufacturing techniques. Furthermore, 230kV polymer insulators are showing signs of deterioration. The deterioration appears due to corona activity on the insulator housing as a result of inadequately controlled electric fields. The degradation exposes the fiberglass rod to moisture which causes rapid deterioration leading to failure.

Since portions of Hydro One's polymer insulator population were approaching their ESL, Hydro One retained EPRI to perform a detailed condition assessment of polymer insulators to assist Hydro One in determining the need and pacing of polymer insulator replacement. The condition assessment study, completed in 2018, focused on 87 polymer insulators from various manufacturers with a service life range of 13 to 26 years.

The condition of the insulators was evaluated through a series of tests which included:

- Visual Inspection;
- Hydrophobicity Assessment;
- Dye Penetration Testing;
- Water Vapor Ingress Testing; and
- Moisture Penetration Test of the End-fittings.

At the conclusion of its condition assessment analysis, EPRI provided Hydro One with its recommendations. Key EPRI recommendations are as follows:

- All 230kV K-Line insulators fitted with 4-inch donut corona rings should be removed from service as soon as possible since they pose a proven risk of immediate failure.
- All the 230kV NGK insulators installed without corona rings should be removed from service as they are considered to be at high risk of failure.
- All the 230kV Ohio Brass polymer insulators installed without corona rings should be removed from service.
- Failed water vapor ingress testing is generally associated with poor bonding between the housing and the rod and is often a batch problem. Until the issue is better understood, these insulators should not be maintained live without first checking their integrity with the EPRI-developed insulator tester.

Based on the study results, Hydro One has implemented the following recommendations into the insulator replacement program:

- Remove from service all 230kV insulators without a corona ring;
- Remove from service all 230kV insulators with 4-inch corona rings or smaller; and
- Continue to monitor 230kV insulators fitted with 8-inch corona rings for signs of degradation.

The need to address the polymer insulator issue is reinforced by several failures. Two failures in 2016 on 230kV circuit T22C polymer suspension insulators resulted in conductor drops, with conductors held within the structure window, as shown in the photos in Figure 13. In 2024, a 230kV polymer insulator failure on circuit P25W resulted in a conductor drop to ground. Some grass was burnt in span, as shown in Figure 14. Hydro One began replacing polymer insulators in a 230kV dead-end configuration in 2016. More recently, a 115kV dead-end polymer insulator failure on circuit C2P (Figure 15) prompted the inclusion of 115kV dead-end polymer insulators in the replacement program. Hydro One will continue to incorporate impacted polymer insulators into the insulator replacement program based on observed condition and risk.

In addition to these findings, Hydro One implemented operational restrictions in 2007 on K-Line polymer insulators due to identified safety and reliability concerns. These restrictions apply to 115kV insulators manufactured before December 2000 and 230kV insulators manufactured before 1999. Under these restrictions, live-line work is prohibited, circuits must be isolated and visually inspected before any work is undertaken, conductors supported by the affected insulators cannot be used to support workers, and removed K-Line units must not be reinstalled. The K-Line 230kV insulators manufactured prior to 1999 were equipped with 4-inch corona rings, which the EPRI assessment identified as requiring replacement due to performance concerns. Although this finding was specific to the 230kV configuration, the 115kV K-Line polymer insulators share similar design-era characteristics and were subjected to the same 2007 operational restrictions, indicating comparable risk. Polymer insulators typically have a 30-year ESL. The K-Line 115kV insulators manufactured prior to December 2000 will be beyond or nearing end of service life during the 2028-2032 period, increasing the likelihood of degradation-related failures

and extending the operational limitations caused by the 2007 restrictions. Given the safety risks, age-related deterioration, historical failure events, and long-standing operational constraints, the K-Line 115kV polymer insulators manufactured prior to December 2000 warrant inclusion in Hydro One's insulator replacement program.

The polymer insulators for replacement consists of approximately 10% of the total insulator replacement population.

Figure 13: T22C Polymer Insulator Failure in 2016

Figure 14: P25W Polymer Insulator Failure in August 2024

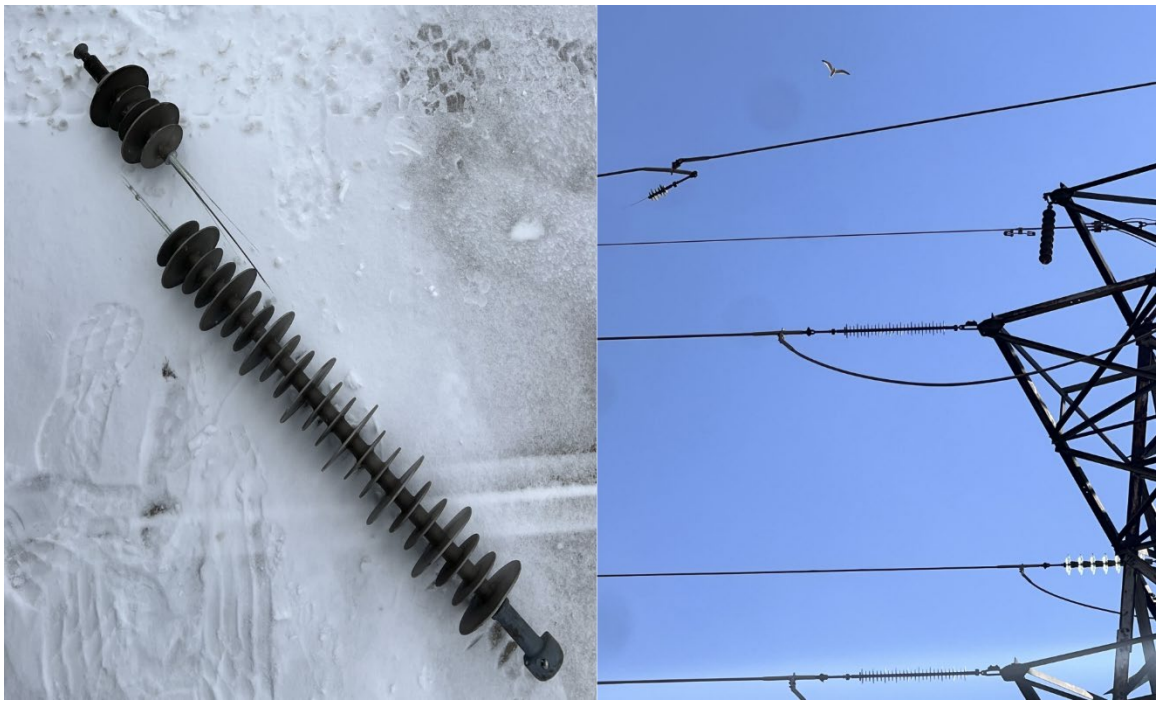

Figure 15: C2P Polymer Insulator Failure in February 2023

3.0 INVESTMENT DESCRIPTION

As transmission line insulators cannot be maintained or repaired to extend their service life, Hydro One targets defective porcelain insulators and deteriorated polymer insulators for replacement as part of the Program. The defective insulators will be replaced with Hydro One-approved insulators. Replacements of defective porcelain insulators will be prioritized to address locations posing a higher public safety risk. Due to their longer ESL, glass insulators are preferred.

During the 2023-2027 prior rate period, Hydro One planned to complete insulator replacements on 3,691 circuit structures per year. Hydro One currently expects to complete 2,865 circuit structures per year on average, due to two primary drivers:

- System outage constraints and cancellations, which directly restricted Hydro One's ability to perform the planned work.
- As described in TSP Section 2.9, Hydro One was required to reprioritize capital expenditures due to increasing demand for non-discretionary and externally-driven investments, coupled with significant cost escalation.

Hydro One plans to replace insulators on 3,400 circuit structures per year during the 2028-2032 planning period to catch up on the deferred work from the 2023-2027 prior rate period and complete the defective insulator replacement work program.

The adoption of live-line insulator replacement methods beginning in 2025 is expected to mitigate some execution constraints associated with planned outage cancellations and support the achievement of the planned replacements assumed in this rate filing. Live-line replacement helps mitigate risks to system reliability and safety by enabling the replacement of defective insulators without taking lines out of service.

The investment's replacement levels for the 2023-2032 planning period for Hydro One has been summarized in Table 2.

Table 2 - Hydro One Insulator Replacements

Zone	Component	Plan[9] 23-27	Act/Fcst[10] 23-27	Forecast 28-32
Hydro One	Insulators (Values reflect number of Circuit Structures addressed)	18,455	14,320	17,000
	% of Fleet (%)	14.8	11.5	13.7

4.0 OUTCOMES

As a result of this investment, Hydro One will reduce public safety risk associated with insulator failures resulting in conductor drops and maintain system reliability by removing electrically and mechanically compromised insulators that may cause forced outages.

4.1 OEB RRF OUTCOMES

Table 3 presents anticipated benefits as a result of the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 3 - Outcomes Summary

Customer Focus	• Eliminate public safety risk associated with defective porcelain insulators. • Maintain system and customer reliability by replacing defective and/or poor condition insulators or in some cases, insulators that are beyond ESL.
Operational Effectiveness	• Maintain system and customer reliability by replacing defective and/or poor condition insulators or in some cases, insulators that are beyond ESL.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence and the TSC to maintain the reliability and integrity of its transmission system.

[9] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[10] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) amounts.

5.0 EXPENDITURE PLAN

As discussed above, the investment is primarily needed to replace the defective COB and CP porcelain insulators and deteriorated polymer insulators that pose significant public safety and system reliability risks.

Table 4 below summarizes Hydro One's planned and actual/forecast net capital expenditures for the 2023-2027 prior rate period and the forecast net capital expenditures for the 2028-2032 planning period.

Table 4 - Hydro One Investment Expenditures[11]

($M)	Plan[12] 23-27	Act/Fcst[13] 23-27	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	431.4	315.6	79.1	80.7	82.3	84.0	85.7	411.8
Less Removals	34.5	24.9	6.3	6.5	6.6	6.7	6.9	32.9
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	396.9	290.7	72.8	74.3	75.7	77.3	78.8	378.9

Over the 2023-2027 rate period, Hydro One expects forecast expenditures to be $106.2M lower than Plan, driven by reductions of $74.2M for investments that were reprioritized as described in TSP Section 2.9, and $32.0M resulting from execution constraints including the cancellation of planned outages required to complete insulator replacement work safely and efficiently.

In the 2028-2032 planning period, Hydro One expects expenditures to be approximately 5% lower than the 2023-2027 Plan, while still completing the replacement of all defective CP/COB porcelain insulators by 2032 and continuing the replacement of deteriorated polymer insulators.

[11] Figures presented in the tables may not sum to the totals shown due to rounding.
[12] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[13] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before proceeding with planned insulator replacement as described in Alternative 2.

ALTERNATIVE 1: STATUS QUO

The Status Quo option is reactive replacement of insulators as they fail. This alternative has been rejected due to the unacceptable public safety risk that occurs when a failure results in a conductor drop. Due to the continued degradation of these defective insulators the number of failures is expected to rise, negatively affecting safety, reliability and customer satisfaction. Furthermore, a systemic investment approach is needed to pace replacements to minimize the impact on customers and reliability.

ALTERNATIVE 2: PLANNED INSULATOR REPLACEMENT

This alternative involves planned replacement of defective porcelain and deteriorated polymer insulators prior to failure. This alternative is recommended as it will reduce the risk to public safety and reliability. In addition, it will enable investment pacing and outage planning to mitigate customer and reliability impacts.

7.0 EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the insulator replacement program include: outage constraints, construction execution challenges, customer coordination, and procurement challenges. To address outage constraints, Hydro One develops a planned outage coordination plan. This plan aims to minimize the loss of supply to customers due to outages. The plan can include switching a customer to an alternative supply. Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. In addition, the adoption of live-line insulator replacement methods beginning in 2025 is expected to mitigate some execution constraints associated with planned outage cancellations and support the achievement of the planned insulator replacements.

1 This page has been left blank intentionally.

T-SR-09	**TRANSMISSION STATION DEMAND AND SPARES**
Primary Trigger:	Asset Failure or High Risk of Failure
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	-	68.4	69.2	69.0	70.0	71.2	347.9
HOSSM[1]	1.1	1.0	1.0	1.0	1.0	1.1	6.2

Summary:

This investment includes the emergency replacement of transmission station assets that have failed or are at an imminent risk of failure and the procurement of strategic spare inventory. The purpose of the investment is to ensure that Hydro One maintains an adequate inventory of critical transmission assets to facilitate the expedient replacement of a failed or deficient component at a transmission station and continue to comply with their legal obligations while mitigating safety, system reliability, and environmental risks that a failure might cause.

[1] See Appendix C for a description of HOSSM's transmission station demand and spares program.

1.0 OVERVIEW

The Transmission Station Demand and Spares investment is a reactive program primarily designed to enable immediate response to, or to minimize the effects of an emergency situation. The investment includes the procurement of spare transmission station equipment such as transformer and breaker operating spares, and the emergency replacement of transmission station equipment that has failed, or is at imminent risk of failure, while in service.

Failed or deficient station equipment may cause an impact on the transmission system that varies from being minor to significant. It may pose safety or environmental risks as well as impose generation and/or power flow constraints, affecting regional load flow limits and customer operations. As licensed transmitters, Hydro One and HOSSM are legally obligated to comply with the planning, operating, and reliability criteria and standards administered by the IESO, as well as requirements which are set out in the Transmission System Code (TSC). This investment ensures that the companies can continue to comply with legal obligations while mitigating safety, system reliability, and environmental risks that an unforeseen failure might cause.

2.0 INVESTMENT NEED

The investment covers the resources required for emergency demand replacement of transformers (including power transformers, reactors, station service transformers), circuit breakers, and other station components[2] that have failed in-service. Additional information regarding the importance of these components to Hydro One's transmission system and the potential failure outcomes is provided in TSP Section 2.2.2 and 2.2.3 as well as ISD T-SR-22. While investments under ISDs T-SR-01, T-SR-03, and T-SR-22 utilize a planned approach to proactively replace poor condition transmission station assets before failure, some equipment will fail prior to replacement.

[2] Other station components include equipment such as switches, capacitor banks, instrument transformers, insulators, arresters, GIS/GIL, low voltage station service switchgear, batteries, chargers, grounding, civil infrastructure, etc. Other station components are further discussed in TSP Section 2.2.3.

Under the TSC, during an emergency, or to prevent or minimize the effects of an emergency, Hydro One is required to take action to ensure public safety; safeguard life, property, and the environment; and protect the stability, reliability, or integrity of its transmission facilities.

If a transmission station asset has failed or is at an imminent risk of failure, it is critical for Hydro One to be able to perform the emergency replacement of that asset as soon as possible to ensure the integrity and reliability of the transmission system and to minimize potential safety and environmental risks. This requires Hydro One to maintain an adequate stock of critical transmission station components such as transformer and breaker operating spares.

When a transmission station asset fails, the impact varies depending on the location of the component and level of redundancy built into the station's electrical configuration. In a best-case scenario, transfer capability is reduced even though the customer will not see any interruption. In the worst-case scenario, where there is stranded load without any transfer capability, customers can be interrupted until the component is replaced (or manually bypassed if possible). Other types of failures of transmission station assets might pose safety or environmental risks.

3.0 INVESTMENT DESCRIPTION

This investment covers the resources required for emergency demand replacement of transformers (including power transformers, reactors, station service transformers), circuit breakers, and other station components that have failed in-service. This includes the necessary design, construction, and commissioning resources to replace failed station equipment.

This investment also includes the procurement of spare transmission station equipment, primarily power transformers and breaker operating spares, to facilitate the timely replacement of failed assets. Transformer and breaker spare inventory levels are based on Markov models which use probability of failure, construction time, carrying costs, and procurement lead time to cost-effectively set the number of spares that are to be kept in inventory. As described in Hydro One's revenue requirement application for the 2020-

2022 period (EB-2019-0082), Hydro One retained a third-party expert, the Electric Power Research Institute (EPRI), to undertake a study to verify that Hydro One's spare transformer requirements are appropriate and consistent with industry best practices. EPRI concluded that Hydro One's operating spare transformer analysis using the Markov model is appropriate.

A breakdown of the number of failed transmission station assets requiring demand replacement over the last 10 years is shown below in Tables 1 and 2.

Table 1 - Hydro One Transmission Station Equipment Demand Replacements

Asset	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	10-year Ave.
Power Transformers	6	2	8	5	3	4	4	0	0	1	3.3
Reactors	2	0	3	0	1	2	1	1	0	0	1.0
Station Service Transformers	1	1	0	0	1	3	0	2	3	2	1.3
Breakers	7	4	5	5	2	6	4	5	1	3	4.2
Other Station Components	49	48	59	67	74	128	82	88	64	56	71.5

Hydro One has historically experienced, on average, 3 to 4 power transformer failures, 4 to 5 breaker failures, and around 70 other individual station component failures annually. The forecasted number of failed units or those at imminent risk of failure expected to be replaced under demand is based on the long-term historical average for this investment.

The number of failed units expected to be replaced under demand and units purchased for strategic inventory for the 2023-2027 and 2028-2032 periods are summarized in Table 2.

Table 2 - Hydro One – Transmission Station Demand and Spares

Zone	Component	Plan[3] 23-27	Act/Fcst[4] 23-27	Total 28-32
Hydro One	Transformer[5] Demand Replacement	25	20	31
	Breaker Demand Replacement	25	19	25
	Other Station Component Demand	398	346	350
	Transformer Spare Inventory Purchases	28	13	30
	Breaker Spare Inventory Purchases	10	24	35

The increase in breaker spare inventory purchases reflects Hydro One's efforts to restore spare inventory levels to those required by the Markov model and to mitigate the impact of extended procurement lead times. Recent spare replenishment orders were also placed to address inventory shortfalls resulting from spare consumption. In addition, although actual and forecast breaker replacements were slightly below Plan for the 2023-2027 period, Hydro One expects breaker demand replacements to be in line with long-term historical averages during the 2028-2032 period as a growing population of breakers exceed their expected service life, are obsolete, or are assessed to be in poor condition across the transmission asset portfolio. Maintaining adequate spare inventory is necessary to support these anticipated replacement activities and to reduce the risk of replacement delays associated with longer equipment lead times.

4.0 OUTCOMES

This investment aims to maintain reliable supply to customers by replacing failed station equipment in a timely manner while mitigating safety and environmental risks and ensuring compliance with legal obligations.

4.1 OEB RRF OUTCOMES

Table 3 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

[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) amounts.
[5] "Transformer" includes power transformers, station service transformers, and reactors.

Table 3 - Outcomes Summary

Customer Focus	• Improve customer satisfaction by minimizing interruptions and providing timely power restoration to customers. • Reduce risk and severity of customer supply interruptions due to lack of operating spares. • Reduce safety risks associated with failing equipment.
Operational Effectiveness	• Maintain transmission system reliability and safety.
Public Policy Responsiveness	• Comply with TSC obligations by providing safe and reliable electricity to Ontario's electricity consumers.

5.0 EXPENDITURE PLAN

Table 4 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 rate period. Costs for the investment are based on current supply chain prices and typical replacement costs applied to the expected demand based on long-term historical failure rates.

Table 4 - Hydro One – Investment Expenditures[6]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	70.9	71.7	71.5	72.5	73.8	360.3
Less Removals	2.4	2.5	2.5	2.5	2.6	12.4
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**68.4**	**69.2**	**69.0**	**70.0**	**71.2**	**347.9**

Table 5 below summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 and 2028-2032 rate periods. Amounts for the 2023-2027 Plan and Actual/Forecast have been adjusted to exclude investment expenditures that have been assigned to different ISDs for the 2028-2032 rate period compared to Hydro One's last transmission Application (EB-2021-0110), as further explained in TSP Section 2.12.

[6] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 5 - Hydro One – Investment Subprogram Expenditures ($M)[7]

Component Replacement Program Description	Plan[8] 23-27	Act/Fcst[9] 23-27	Total 28-32
Transformer Demand Replacement	68.0	48.0	107.0
Transformer Spare Purchasing	74.3	83.7	119.8
Breaker Demand Replacement	11.8	8.8	13.2
Other Station Component Demand Failures	49.3	100.9	100.7
Below Materiality	4.6	8.3	7.2
Total	208.1	249.6	347.9

Over the 2023-2027 rate period, Hydro One expects actual and forecast expenditures to be $41.5M higher than Plan, driven by transformer spare purchasing and other station component demand failures. Contributing to the variance for these programs is higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historical material cost escalation trends are described in SPF Section 1.8.3, including power transformers, which have increased by 115% on average since 2020.

Additionally, the mix of types of other station component demand failures varied from expected, resulting in higher expenditures than planned due to an increased quantity of disconnect switch, insulator, AC station service, and gas insulated switchgear component replacements. The complexity and cost of addressing this category of asset failures is highly variable. For instance, station service switchgear and gas insulated switchgear component demand failures are more complex and costly relative to a failed instrument transformer replacement.

[7] Figures presented in the tables may not sum to the totals shown due to rounding.
[8] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110. "Plan" excludes expenditures mapped to T-SR-09 in EB-2021-0110 that are now mapped to other ISDs.
[9] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures. "Act/Fcst" excludes expenditures mapped to T-SR-09 in EB-2021-0110 that are now mapped to other ISDs.

Over the 2023-2027 rate period, Hydro One expects actual and forecast expenditures for transformer and breaker demand replacements to be lower than Plan due to fewer emergency replacements than expected.

The forecast expenditures in the 2028-2032 planning period are $98.3M higher than the actual and forecast expenditures in the 2023-2027 rate period. As shown in Table 5, the increase is concentrated in Transformer Demand Replacements and Transformer Spare Purchasing. The increase is primarily driven by the inflationary pressures described above, which drive higher replacement costs, including the material cost escalation noted for power transformers. The amount and mix of Other Station Component Demand Failures are expected to continue into the 2028-2032 planning period, with failure rates aligned with long-term historical averages.

6.0 ALTERNATIVES

This investment is non-discretionary and, as such, no alternatives have been considered. Under the TSC, a transmitter is required to take action during an emergency to ensure public safety and to safeguard life, property and the environment as well as to protect the stability, reliability, and integrity of its transmission facilities. Failure to respond to an emergency or to prevent or minimize the effects of an emergency in a timely manner may jeopardize public and/or employee safety or negatively impact the provision of reliable service. For example, the lead time to procure a new transformer can take several years. As a result, failing to have adequate spare transformer inventory on hand would introduce lengthy replacement timelines and negatively impact system reliability.

7.0 EXECUTION RISK AND MITIGATION

The risks of potential customer supply interruptions and longer outages caused by failed station equipment must be mitigated by a timely response. There are risks to executing such unplanned work including the availability of resources and long lead times for the purchase of new equipment. The risk of resources being unavailable is mitigated by having a process to enable the effective prioritization of resources to support immediate and emergent work as required and risk of long procurement lead times is mitigated by having an adequate inventory of critical spare equipment.

APPENDIX C – HOSSM TRANMSISSION STATION DEMAND AND SPARES

As described in TSP 2.10, Hydro One has been operationally integrated with HOSSM since October 1, 2018. However, HOSSM remains financially and legally separate until such time that a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One.

HOSSM continues to be the licensed owner and operator of its transmission system. However, it relies on Hydro One to carry out the day-to-day operations, pursuant to affiliate service agreements as outlined in Exhibit D-02-03. Although HOSSM is distinct and its approved revenue requirement is established separately, many processes including asset management, planning and work execution approaches are common and integrated with Hydro One Transmission and are described within Hydro One's SPF and TSP.

Since HOSSM's programs are operationally integrated with Hydro One, the investment need, investment description, outcomes, and execution risks and mitigation described above for Hydro One in Sections 2.0, 3.0, 4.0 and 7.0, respectively, are applicable to HOSSM's transmission station demand and spares programs.

For HOSSM, the forecasted number of failed units expected to be replaced under demand is expected to be approximately consistent with the 2022-2026 actual and forecast amount, which is approximately 3-4 units per year on average. It is not anticipated that any additional purchases of strategic inventory are required for HOSSM.

HOSSM's 2022-2026 actual/forecast replacement levels and planned replacement levels for the 2027-2032 period are summarized in Table C-1. The increased replacement level for the 2027-2032 period reflect an additional year.

Table C-1 - HOSSM – Transmission Station Demand and Spares Replacement Levels

Zone	Component	Act/Fcst[10] 22-26	Total 27-32
HOSSM	All station assets	18	24

Table C-2 summarizes HOSSM's actual and forecast capital expenditures for the 2022-2026 rate period and the forecast capital expenditures for the 2027-2032 rate period. Costs for the investment are based on recent actual average costs applied to the expected demand over the 2027-2032 period.

Table C-2 - HOSSM – Investment Expenditures[11]

($M)	Act/Fcst[12] 22-26	2027	2028	2029	2030	2031	2032	Total 27-32
Gross Capital Expenditures	5.1	1.1	1.1	1.1	1.1	1.1	1.1	6.7
Less Removals	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.5
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**5.0**	**1.1**	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**	**6.2**

Table C-3 below summarizes HOSSM's actual and forecast net capital expenditures for the 2022-2026 rate period and planned net capital expenditures for the 2027-2032 rate period. These expenditures are presented according to the investments comprising this investment, as described in Section 3.0.

Table C-3 - HOSSM – Investment Subprogram Expenditures ($M)

Component Replacement Program Description	Act/Fcst[13] 22-26	Total 27-32
All Station Component Demand Replacement	4.7	6.2

[10] "Act/Fcst" refers to actual (2022-2025) and forecast (2026) expenditures.
[11] Figures presented in the tables may not sum to the totals shown due to rounding.
[12] "Act/Fcst" refers to actual (2022-2025) and forecast (2026) expenditures.
[13] "Act/Fcst" refers to actual (2022-2025) and forecast (2026) expenditures.

As noted above for Hydro One in Section 6.0, this investment program is non-discretionary and, as such, no alternatives have been considered. Failure to respond to an emergency or to prevent or minimize the effects of an emergency in a timely manner may jeopardize public and/or employee safety, negatively impact the provision of reliable service.

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T-SR-10	**PROTECTION RELAY REPLACEMENT PROGRAM**
Primary Trigger:	Obsolescence
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	27.3	33.3	35.2	39.5	40.2	175.5

Summary:

This investment addresses the replacement of aging protection systems that present an elevated risk of delivery-point interruptions and could negatively affect the reliability of the transmission network. Renewal of these assets is essential to mitigate system reliability and safety risks, and to maintain ongoing compliance with applicable North American Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC) protection and control standards.

The proposed capital expenditures in the 2028-2032 planning period reflect a higher replacement rate resulting primarily from the growing population of relays identified as being beyond expected service life (ESL) or as obsolete, as well as work deferred work from the 2023-2027 period.

1.0 OVERVIEW

Hydro One's protection systems comprise instrument transformers, relays, sensors and communication devices. The protection system is a critical element of the transmission system that detects abnormal system conditions. Upon detecting an abnormal condition, the protection systems immediately initiate the necessary station equipment to operate to isolate faulted components. If not isolated in time, a faulted element can cause a cascading effect resulting in a major system disruption involving service interruptions, equipment damage and employee and public safety issues. Hydro One's protection systems are installed at both transmission network stations and connection stations.

The Protection Relay Replacement investment is a program that involves the replacement of protection systems operating beyond their ESL. Hydro One uses the ESL of relays as a trigger for protection replacement assessment to investigate a relay, including the risk of its potential failure with respect to reliability and safety, spare availability and availability of vendor support.

It is not feasible to assess the physical condition of this class of asset, as most components of protection systems do not show signs of wear and fatigue. They usually operate until they suffer an abrupt failure. As a result, other factors are used as triggers for replacement decisions, including: increased failure rates related to specific models or families of devices, limited or non-existent manufacturer support (i.e., in terms of the provision of spare parts and repair services), obsolescence and the inability to comply with current reliability standards. With respect to the priority of protection replacements, Hydro One's strategy is to target protections with a high likelihood of failure.

This investment is complementary to Hydro One's integrated station investments and comprises the planned replacement of aged and obsolete assets that are not included in the integrated station projects described in ISDs T-SR-01, T-SR-02 or T-SR-03.

2.0 INVESTMENT NEED

To mitigate the risk of equipment failure and the resulting adverse consequences to public and employee safety, the environment, and system reliability, this investment includes the planned replacement of aged and obsolete assets.

The ESL of protection devices plays an important role in the assessment of protection relay replacement needs. This is because assessment for physical breakdown or loss of strength over time is not relevant given the make-up of these electronic or solid-state devices. As such, to prevent the potentially significant reliability and safety impact of a sudden failure, ESL is necessarily a key trigger for further evaluation to confirm replacement needs.

Protection devices operating beyond ESL are subject to an elevated risk of failure, while also having very limited or no support from vendors in terms of replacement units, spare parts, and engineering and firmware support. As such, reactive repairs may involve extended durations as re-engineering and construction work will be required to install new devices based on different technology. These risks could lead to protracted outages for customers.

Hydro One currently has 12,748 protection systems in-service. As further described in TSP Section 2.2.2.3, there are three vintages of protection systems in Hydro One's transmission system: Electromechanical, Solid State and Microprocessor. Approximately 26% of the protection system population is currently operating beyond its ESL. Table 1 below presents a summary of Hydro One's protection systems by technology type and the proportion of each type operating beyond ESL.

Table 1 - Summary of the ESL of Hydro One's Protection Systems by Technology*

Protection Type	Quantity	Avg. Age (Years)	ESL (Years)	Beyond ESL*	
				2026	
				Qty.	% of Type
Solid State	1,335	40.8	25	1,207	90.4%
Electromechanical	2,349	44.3	45	1,263	53.8%
Microprocessor	9,064	11.5	20	859	9.5%
TOTAL	12,748	-	-	3,329	26.1%

Hydro One's strategy for protection systems is focused on replacing systems that have a high likelihood of causing delivery point interruption and impacting the reliability of the Bulk Electric System (BES) with modern integrated systems. Given Hydro One's protection system fleet demographics, performance, and risks associated with equipment failures, a continued focus on replacement efforts is required to maintain system reliability performance.

In addition, due to the shorter ESL of new technologies, the rate of relay replacements will increase in order to maintain Hydro One's ability to manage future relay failures and to manage replacement of aged and obsolete assets to keep risks at an acceptable level. Relay replacement volumes must increase to ensure a sustainable renewal rate that reflects the shorter ESL of newer technologies as well as the deteriorating performance and the increasing age of the fleet. In particular, the growing proportion of microprocessor-based relays increases the need for investment in this equipment. As microprocessor-based relays are now the only viable protection technology, replacement rates will increase due to their significantly shorter ESL. While obsolete electromechanical relays typically operate for 40-60 years, modern microprocessor relays have an ESL of roughly 20 years, with failure rates expected to rise beyond that point.

A significant proportion of Hydro One's solid state and electromechanical relay fleets are already operating beyond ESL. Given that microprocessors are the predominant replacement, the relatively shorter ESL of microprocessors will cause renewal requirements for all vintages of relays to increasingly overlap, causing an accumulation of assets requiring replacement over the rate period.

Overall, this strategy will help ensure that Hydro One continues to manage reliability, safety, and compliance risks across its protection system fleet while modernizing toward more capable and maintainable technologies.

3.0 INVESTMENT DESCRIPTION

While Hydro One has a number of transmission station protection systems that are beyond ESL, the pacing of the investment does not target all of them. The investment addresses the most critical and pressing protection issues that require attention considering outage constraints, and supply chain availability.

During the 2028-2032 planning period, under this program, Hydro One plans to replace an average of 105 relays each year, totaling 528 relays, which represents only 4.1% of the fleet. As shown in Table 1 above, planned replacements account for a small portion of the 26% of the fleet that is beyond ESL. An additional 965 relays, or 7.5% of the fleet are expected to be replaced through material investments under the complementary integrated station ISDs (i.e., T-SR-01, T-SR-02 and T-SR-03) during the 2028-2032 period.

The proposed pacing for this investment is higher than the historical average due to the following:

- A considerable population of relays has been identified as being beyond ESL and obsolete, including a growing population of microprocessor relays with shorter service lives.
- Hydro One planned to replace approximately 210 relays during the 2023-2027 period but expects to complete approximately 124 relays by the end of 2027, resulting in deferred work. During the 2023-2027 period, the scope and cost of replacements increased to accommodate the implementation of updated Hydro One protection standards requirements needed to support modern firmware, enhanced cybersecurity requirements, revised NERC Protection and Control (PRC) obligations, and improved relay performance specifications. These enhancements often required additional engineering, testing, and integration work compared to like-for-like replacements. The increased work scope put pressure on available capital funding. To contain total investment costs within the capital

envelope, Hydro One temporarily reduced relay replacement levels and prioritized replacements to manage within the funding envelope.

Increased pacing is needed to keep pace with the growth of the relay population that is beyond ESL.

The investment's replacement levels for the 2023-2032 period are summarized in Table 2.

Table 2 - Protection Relay Replacement

Zone	Component	Plan 23-27[1]	Act/Fcst 23-27[2]	Forecast 28-32
Hydro One	Protection Relay (Unit)	210	124	528
	% of Fleet	1.7	1.0	4.1

4.0 OUTCOMES

As a result of the investment, Hydro One anticipates the following outcomes:

- **Safety** – Replacement of beyond ESL and obsolete protection systems will mitigate risks to employee and public safety. Protection system failure to operate can potentially expose workers and the public to the risk of electrocution, which can result in significant injuries or fatalities.
- **Regulatory Compliance** – Hydro One's protection system must comply with all applicable NERC and NPCC standards. Protection system upgrades are often needed in order to comply with new or updated standard requirements. The investment ensures compliance.
- **System Reliability Risk** – The investment mitigates issues associated with system reliability. The impact of protection systems on power system reliability depends on its location in the power system, the criticality of the protected element, protective function and redundancy. Power system reliability risk due to potential protection failure or mis-operation is being factored into the replacement decision process.

[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) amounts.

- **Innovation** – New microprocessor-based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage. Modern protections include self-monitoring features which alert control room staff when they fail. The control room can then take appropriate action and dispatch crews to perform repairs. Older style relays, such as electromechanical relays, do not contain these features. Their malfunction can only be detected during routine maintenance or when they fail to perform as designed during system events.

4.1 OEB RRF OUTCOMES

Table 3 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 3 - Outcomes Summary

Customer Focus	• Maintain reliability performance of bulk electricity system power flows through the replacement of beyond ESL protection systems. • Mitigate employees' and public safety risk from protection system failure to operate.
Operational Effectiveness	• Improve operational flexibility of the bulk electricity system through the implementation of modern protection and automation systems, enabling enhanced telemetry, control, and operational capabilities
Public Policy Responsiveness	• Comply with applicable regulatory requirements

5.0 EXPENDITURE PLAN

As discussed above, the investment is needed to replace the protection systems at network and connection stations which may compromise the reliability of supply due to the high-risk assets that have reached their ESL. Table 4 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 4 - Hydro One – Investment Expenditures[3]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	27.4	33.4	35.3	39.6	40.4	176.0
Less Removals	0.1	0.1	0.1	0.1	0.1	0.5
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**27.3**	**33.3**	**35.2**	**39.5**	**40.2**	**175.5**

The factors influencing the cost of the investment include:

- Applicability of NERC and NPCC requirements
  - Replacement of protection and automation systems must comply with applicable NERC and NPCC requirements. When protection/control equipment is replaced, the systems must be designed to meet the applicable NERC and NPCC requirements, as applicable to the relevant station elements being replaced (e.g., implementation of newer protection standards or redundancy requirements of protection systems, AC and DC supply, physical and diverse separation of equipment). These requirements can significantly increase the cost of replacement.
- Need for additional civil infrastructure such as cable trenching, and/or ducts
  - This could include physical separation of A and B communication paths which can result in a significant cost increase. This requirement is mandated by the applicable NPCC design criteria.
- Available space within the control building or relay room to facilitate upgrades
  - Additional facilities may need to be installed to connect the equipment rather than re-using existing facilities. For instance, increased relay room rack space may be needed to accommodate the new equipment. Alternatively, the lack of space or additional cabling in cable pans could trigger the need for a new relay building.
- Complexity of stages and outages required to facilitate work
  - Complexity of the work can increase planning costs.
  - Longer overall project durations can increase total project cost.

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 5 summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 prior rate period and planned net capital expenditures for the 2028-2032 planning period.

Table 5 - Hydro One – Rate Period Net Investment Expenditures[4]

Description	Plan[5] 23-27	Act/Fcst[6] 23-27	Total 28-32
Protection Relay Replacement Program	62.9	67.1	163.8
Below Materiality	13.2	18.2	11.7
Total	76.1	85.3	175.5

Over the 2023-2027 prior rate period, Hydro One expects actual and forecast expenditures for the Protection Relay Replacement Program to exceed Plan by $4.2M, primarily due to increased work scope to satisfy Hydro One's standards requirements. As described in Section 3.0 above, during the 2023-2027 period, the scope and cost of replacements increased to accommodate the implementation of updated Hydro One protection standards requirements needed to support modern firmware, enhanced cybersecurity requirements, revised NERC PRC obligations, and improved relay performance specifications. These enhancements often required additional engineering, testing, and integration work compared to like-for-like replacements.

In the 2028-2032 planning period, Hydro One expects the expenditures for the investment to be $90.2M higher than the 2023-2027 actuals and forecast due to a higher expected replacement rate. As described above, the higher replacement rate for the 2028-2032 planning period reflects the growing number of relays operating beyond ESL, including an increasing population of microprocessor relays with shorter service lives, as well as reduced replacement during the 2023-2027 prior rate period.

[4] Figures presented in the tables may not sum to the totals shown due to rounding.
[5] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[6] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENT

This alternative involves waiting for protection systems to fail and replacing components on a reactive basis, which is more costly. Hydro One has rejected this alternative for the following reasons.

- Protection systems operating beyond ESL or that are obsolete will remain in service, maintaining or increasing the likelihood of unexpected failures. These failures could be prolonged and result in extended equipment and customer outages, which could adversely affect System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) performance.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would continuously result in the reprioritization of planned work and inefficient redeployment of resources.
- This alternative limits the ability to incorporate evolving and future requirements into the replacement work scope, which presents a material risk of re-work and future costs.
- IESO's Market Assessment and Compliance Division may impose sanctions, including financial penalties, as a result of a potential non-compliance to a NERC or NPCC standard.

ALTERNATIVE 2: PLANNED COMPONENT REPLACEMENT (RECOMMENDED)

This is the preferred investment option. It involves proactive replacement of protection systems that are operating beyond their ESL, before failures occur. Hydro One's replacement strategy for protection systems is focused on replacing systems that have a high likelihood of causing delivery point interruption and impacting the reliability of the bulk electricity system. Because it is not feasible to assess the physical condition of protection systems, ESL and other factors are used as a trigger to identify high risk assets which

undergo further condition assessment to identify replacement candidates, as discussed above. Other factors in driving protection system replacements are summarized below.

- **Safety** – Protection system failure to operate can potentially expose workers and the public to the risk of electrocution, which can result in significant injuries or fatalities. Proactive replacements are required to mitigate this risk.
- **Regulatory Compliance** – Hydro One's protection system must comply with all applicable NERC and NPCC standards. Protection system upgrades are often needed in order to comply with new or updated standard requirements.
- **Historical Performance** – Failure rates over the historical period for a particular relay model are used to help identify fleet deterioration of that specific relay model.
- **System Reliability Risk** – The impact of protection on power system reliability depends on its location in the power system, the criticality of the protected element, protective function and redundancy. Power system reliability risk due to potential protection failure or mis-operation is being factored into the replacement decision process.
- **Functional Requirements** - The requirements for protection system functionality may change due to power system changes (e.g., system stability requirements) or changes to other components of the integrated protection and automation system, which may lead to incompatibility of the existing protection hardware with the associated devices.
- **Obsolescence** – Many protection system components are no longer available, limiting the availability of spare parts and support; which can adversely impact outage planning and overall system reliability. This is a significant factor for electromechanical and solid-state systems as they are no longer supported by relay vendors which are focusing their efforts on microprocessor-based relays.
- **Innovation** – New microprocessor-based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage.

This alternative is recommended as it addresses the needs identified at the transmission station to maintain reliability for Hydro One's bulk transmission system in a cost-effective manner.

7.0 EXECUTION RISK AND MITIGATION

Risks that can impact the completion of protection systems replacement projects are: outage constraints, construction execution challenges, customer coordination, real estate requirements, or procurement challenges. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial investment planning phase where all known risks are identified, and a mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan aims to minimize the loss of supply to the customer (i.e., switching a customer to an alternative supply). Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages. While protection and automation replacement projects are rarely real estate dependent, in some cases there is a need to involve real estate from the project's inception. This allows for the early identification and resolution of real estate issues prior to execution of the project.

T-SR-11	**LEGACY SONET SYSTEM REPLACEMENT**
Primary Trigger:	Obsolescence
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Net Cost	25.1	22.9	7.2	0.4	0.0	55.5

Summary:

Hydro One's core telecommunication network is based on Synchronous Optical Network (SONET) transport technology and is primarily utilized for protection and automation systems between Hydro One's control centres, hub sites and transmission stations. This investment involves the replacement of Hydro One's SONET system with a new packet-based system and the primary trigger of the investment is technological obsolescence of the legacy SONET system.

Hydro One previously expected to place the investment in service in 2027, but delayed commencement of the installation of the new network to obtain more comprehensive estimates for the execution of the investment, which involved completing a Request for Proposal, conducting Proof of Concept testing to validate the vendor proposal and defining the overall network architecture design. Hydro One now expects to place the investment in service in 2031.

The investment is currently in the execution phase and is intended to improve the reliability of Hydro One's telecom system serving tele-protection and supervisory control systems.

1.0 OVERVIEW

Legacy SONET System Replacement involves the replacement of Hydro One's SONET system with a new system based on Multiprotocol Label Switching (MPLS) technology. The SONET system at Hydro One is primarily utilized for protections and automation, including Supervisory Control and Data Acquisition (SCADA) systems. The SONET system, along with the physical infrastructure (optical fibre and microwave-based systems) that establishes communication links, are the cornerstones of protection and automation systems, which support grid reliability as well as protection of costly station and line assets. Additionally, SONET is used for communicating non-operational data, business data, voice and security information.

A significant portion of Hydro One's SONET system, which primarily includes multiplexer equipment at transmission stations, is facing technological obsolescence based on the factors listed below:

- Large segments of the system have exceeded their expected service life (ESL);
- Vendors have withdrawn support (end of vendor support); and
- Increasing challenges and lead times to procure SONET equipment spares.

When end of vendor support is reached, spare parts become increasingly harder to procure, which leads to repairs and maintenance becoming increasingly costly and challenging, and systems being at risk of longer outages and degraded reliability. Hydro One's first generation of SONET system (the Legacy System) equipment has reached its ESL and the equipment has reached its end of vendor support.

Other factors contributing to the need for this investment include:

- The Legacy System equipment accounts for the majority of SONET equipment failures, as described below.
- The SONET system is critical for the operation of the grid and equipment failures can have a high grid reliability impact.
- Accelerated rate of failures in the future could require replacement volumes that would be impossible to execute due to Hydro One's very large installed base.

Failures caused by SONET equipment have resulted in multiple power system telecom services being rendered unavailable until repaired. Loss of power system telecom services can result in real-time control actions to be taken in order to either constrain power flow on the transmission system and/or to remove power system elements such as breakers, lines, and transformers from service. In turn, these actions can negatively impact the reliability of the transmission system and potentially expose customers to the system operating in a less reliable grid configuration. To address the reliability issues associated with the obsolescence of the technology and network equipment on which SONET is built, Hydro One evaluated various alternatives for the investment as described below, and is in the process of replacing the legacy system with new packet-based technology.

2.0 INVESTMENT NEED

The SONET communications network is primarily utilized for critical protection and SCADA applications. Critical protection means communications that are essential for the safe and reliable operation of the transmission system. These are protection trip signals that are initiated by protection systems to isolate high voltage equipment during fault conditions to prevent further or widespread outages. This can include the tripping of circuit breakers at multiple stations by sending a signal from one station to another through the SONET network in order to isolate a fault on a transmission line. Operation of the transmission system also requires equipment telemetry and status information being continuously communicated to the Integrated System Operating Centre (ISOC) through the SONET network.

The SONET network multiplexer equipment is composed of two vintages; the first generation that was initially deployed between 1998 and 2007 and the second generation that was installed starting in 2004. In addition to the multiplexer equipment, other key components that make up the SONET network include microwave links, optical amplifiers and 48Vdc backup power supplies. The network topology is such that communication rings are created connecting the stations to provide redundant communication links that can stretch hundreds of kilometers across the province.

There are certain segments of the network that are made up of microwave links as opposed to fibre-connected paths. Over time they have created capacity and bandwidth

limitations on a typical ring topology. Higher capability equipment is not available from the vendor because microwave links are viewed as obsolete. Replacement of these microwave links is not covered by this investment and is instead the subject of the Telecom Performance Improvement investment (TSP Section 2.12, T-SR-12).

Hydro One utilizes asset ESL information as a screening factor for asset replacement, along with hardware obsolescence or level of vendor support, spare equipment availability, performance or failure rates and equipment conditions from preventive maintenance findings. Given the nature of these assets, it is not feasible to assess their actual physical condition. As such, field deficiency reports, trouble calls and failure incidents provide an indication of the overall condition of the power system telecom assets and play a role in determining whether to replace the SONET network.

The ESL for most microprocessor-based equipment is 15-20 years. Table 1 below shows typical ESL in years for various types of equipment on the SONET communication network.

Table 1 - Summary of SONET Equipment

Telecom System/Asset Class	Asset Type	Quantity	Expected Service Life (Years)	Quantity Beyond ESL[1]
SONET Communication Network	Multiplexers	276	15	221
	Digital Radios	16	15	16
	Optical Amplifiers	32	15	28
	48 VDC Batteries	239	10-20[2]	57
	48 VDC Chargers	239	20	43

The first vintage of multiplexer equipment includes large segments that are currently beyond their ESL and are facing technological obsolescence as vendors withdraw support. As such, it has become challenging to repair defective components, and spare parts continue to be increasingly harder to source. The majority of SONET equipment failures continue to be associated with the first vintage of multiplexer equipment (Vintage A MUX) as shown in Figure 1 below, which has experienced increasing failure rates. These failures

[1] Data as of December 2025.
[2] Varies based on equipment make and/or model.

have resulted in multiple power system telecom services being rendered unavailable until corrective repairs were carried out.

Loss of communications channels from SONET equipment failures can result in the removal of power system equipment from service and/or power flow constraints on the transmission system (as protection systems dependent on communications cannot protect the equipment and the ISOC can lose visibility into the status of the equipment and system power flows). In turn, these conditions can have a negative impact on communications availability in support of NERC and NPCC requirements for protection systems, the reliability of the transmission system, and potentially expose Hydro One and its customers to less reliable operating configurations, which can lead to equipment being forcibly removed from service.

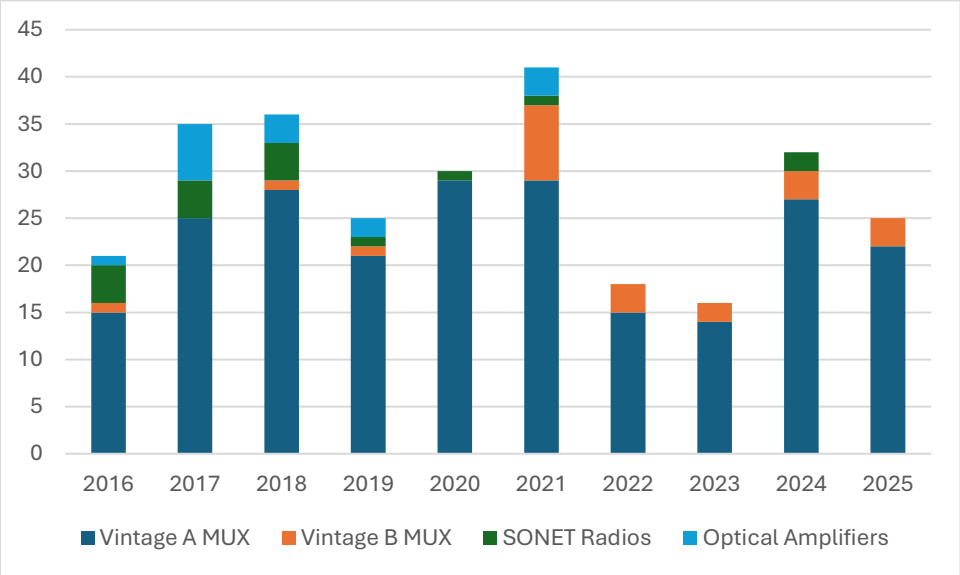

Figure 1: Failure Incidents for SONET Equipment

3.0 INVESTMENT DESCRIPTION

Given the obsolescence of both the technology and network equipment on which SONET is built, Hydro One has developed the investment to replace the Legacy System with a modern solution that replaces the first vintage of SONET multiplexers that have been in service for close to 25 years with a solution based on Multiprotocol Label Switching (MPLS) technology at over 70 stations.

Based on the assessments and results obtained from the development phase, which included technology evaluations, proof of concept testing and field trials, MPLS was selected as the new replacement technology that satisfied Hydro One's technical requirements. An overall implementation and staging plan was developed, which included selection of the specific replacement solution from market participants, followed by multi-year systematic replacements.

Installation of the core components of the new network and the initial group of MPLS nodes is planned to begin in 2026, with migration of the first group of services to the new platform starting in 2027. Hydro One expects to in-service the new MPLS infrastructure by 2029, with service migrations for all nine rings of the legacy SONET communications network and associated removals targeted for completion by 2031.

As the network undergoes this changeover, both the existing and the new platforms are being operated and maintained until completion of the migration.

4.0 OUTCOMES

The investment results in Hydro One's continued ability to support safe and reliable operation of the transmission system by migrating power system telecom services from Hydro One's legacy SONET system to the new replacement platform. In addition to its utilization for protection and SCADA systems, the new technology also enables the cost-effective deployment of applications that require modern IP connectivity and higher bandwidth, as well as eliminating the performance limitations and failures attributed to the older multiplexer equipment. The additional bandwidth available on the new replacement system also allows Hydro One, where possible, to migrate services that are currently dependent on leased circuits due to high bandwidth requirements onto the new communication system.

4.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 2 - Outcomes Summary

Customer Focus	• Maintain telecommunication reliability for protection and SCADA systems thereby maintaining the quality of service to customers.
Operational Effectiveness	• Maintain reliability of the transmission system by ensuring the communication network used for protection, control and monitoring of the grid is reliable. • Reduce dependency on third-party leased services by leveraging the new replacement communications system, where possible.
Public Policy Responsiveness	• Hydro One is obligated to build and maintain a redundant communication/protection system to ensure that Hydro One meets NERC transmission system performance standards.

5.0 EXPENDITURE PLAN

Table 3 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 3 - Investment Expenditures[3]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	25.3	22.9	10.3	2.2	0.0	60.7
Less Removals	0.3	0.0	3.1	1.9	0.0	5.2
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	25.1	22.9	7.2	0.4	0.0	55.5

Major factors influencing the cost of the investment include:

- The large installed base of SONET equipment over a broad geographical area; and
- Coordination and complexity of outages required to replace the SONET communications systems.

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 4 includes the **p**rior **p**roject **t**otal, current **p**roject **t**otal, as well as the maturity of the project at the time of filing, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

Table 4 - Material Investment Net Expenditures

Investment Name	Type	Prior Proj. Total[4]	Prior In-Service Year	Type	Proj. Total	In-Service Year
Legacy SONET System Replacement	P	123.7	2027	E	125.9	2031

Hydro One expects to place the new MPLS infrastructure in service by 2029 with completion of all service migrations and removals targeted by 2031 at a forecast project total of $125.9M. The original plan to begin installation of the new network and migration of services early in the 2023-2027 rate period was deferred to ensure more comprehensive estimates are produced through Request for Information and Request for Proposal developments, as well as conducting customer Proof of Concept testing to validate the proposed solution. This allowed Hydro One to reduce the likelihood of unforeseen complexities during execution of the work. Installation of the new network commenced in 2026. Hydro One expects to incur expenditures of $70.4M (net of removals) prior to 2028.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred investment.

ALTERNATIVE 1: STATUS QUO

This alternative involves replacing the legacy SONET equipment as it fails. This alternative was rejected as reactive replacements result in unplanned equipment outages that negatively impact communication system performance and service to customers. Repair times can be longer due to material sourcing delays. Because SONET equipment faced obsolescence, Hydro One's inventory of spare parts continues to diminish, further reducing the viability of maintaining the legacy system on a reactive basis.

[4] Prior Proj. Total refers to the Project Total related to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

ALTERNATIVE 2: PLANNED SONET REPLACEMENT (RECOMMENDED)

This is the preferred undertaking. This alternative replaces the legacy SONET system with a solution based on MPLS technology. It allows Hydro One to maintain the reliability of the transmission system and replacements to be planned and coordinated. This also allows outages to be scheduled, thereby reducing outage impacts, which in turn alleviates the impact on communication system performance and Hydro One's customers. Complete replacement also enhances the capabilities of the communication network resulting in the availability of communication infrastructure for future communication applications.

7.0 EXECUTION RISK AND MITIGATION

The main risk to the investment is service migration timelines due to the large installed base of the SONET system, which could result in delays. The primary source of potential delays is the need to secure outages to migrate power system telecom services to the new replacement platform. In order to mitigate any potential impact to system reliability from such delays, the legacy SONET system will continue to be maintained until migration to the new replacement system is completed.

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T-SR-12	**TELECOM PERFORMANCE IMPROVEMENTS**
Primary Trigger:	Obsolescence
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	15.1	14.4	12.8	6.6	6.8	55.8

Summary:

Hydro One's core telecommunication network is based on Synchronous Optical Network (SONET) transport technology and is primarily utilized for protection and automation systems between Hydro One's control centres, hub sites and transmission stations. The network structure is such that stations are connected in the form of rings to provide redundant communication links that can stretch up to hundreds of kilometers across the province. This investment installs Optical Ground Wire (OPGW) on line B22D/B23D, which is part of SONET Ring 6, to replace obsolete digital microwave equipment.

The primary triggers of the investment are technological obsolescence and NERC and NPCC regulatory compliance requirements.

Hydro One expected to place the investment in service during the 2023-2027 period, but the investment was delayed due to capital reprioritization required during the historical and bridge period, as described in TSP Section 2.9.

The consequences of further delay or deferral of this investment are the potential failure of the obsolete equipment that is no longer manufactured or has reached end of life. Failure of SONET equipment could lead to loss of the automation and protection function, extended transmission line outages, and lower reliability of the overall power system.

1.0 OVERVIEW

Hydro One's existing SONET system is supported by physical infrastructure that establishes the communication medium that links transmission stations and control centers. The vast majority of these communication links utilize Hydro One owned or leased fibre-cable infrastructure, however, certain links are microwave based. The Telecom Performance Improvements investment involves the replacement of obsolete digital microwave links with optical ground wire (OPGW) on line B22D/B23D which is part of the SONET Ring 6. This investment is complementary to and mutually exclusive from the Legacy SONET System Replacement project (ISD T-SR-11), which will replace multiplexer equipment that is beyond its expected service life (ESL) and is facing technological obsolescence with Multiprotocol Label Switching (MPLS) technology.

This investment will establish more robust and reliable fibre-based communication links within SONET Ring 6, and these links will continue to be part of the new MPLS infrastructure.

The equipment that comprises these microwave links is facing technological obsolescence based on the factors listed below:

- The equipment is beyond its ESL; and
- The equipment is no longer being manufactured, and vendors have withdrawn support (end of vendor support).

When end of vendor support is reached, spare parts become increasingly harder to procure, which leads to repairs and maintenance becoming increasingly costly and challenging, and systems being at risk of longer outages and degraded reliability.

Loss of communication channels from SONET equipment failures, including from obsolete microwave links, can result in the removal of power system elements from service and/or power flow constraints on the transmission system (as protection systems dependent on communications cannot protect the equipment and the Integrated System Operating Centre (ISOC) can lose visibility into the status of the equipment). In turn, these conditions can have a negative impact on communications availability in support of NERC and NPCC

requirements for protection systems, the reliability of the transmission system, and potentially expose Hydro One and its customers to less reliable operating configurations. This can lead to equipment being forcibly removed from service. In addition to the high reliability risk, these legacy microwave links create a bandwidth bottleneck on the SONET network, limiting the full utilization of the capacity of the SONET rings.

In light of the foregoing, the investment is needed to improve the communication network's reliability and functionality by eliminating microwave links that create a bottleneck. Hydro One has evaluated various alternatives for the investment, as described below, and concluded that proactive replacement of the obsolete equipment is the most cost effective and efficient undertaking. All projects associated with this investment are expected to be completed by 2030.

2.0 INVESTMENT NEED

Hydro One's core telecommunication network is based on SONET transport technology and is primarily utilized for critical protection and automation systems between Hydro One's control centres, hub sites and transmission stations. Critical protection means communications that are essential for the safe and reliable operation of the transmission system. These are protection trip signals that are initiated by protection systems to isolate high voltage equipment during fault conditions to prevent further or widespread outages. This can include the tripping of circuit breakers at multiple stations by sending a signal from one station to another through the SONET network in order to isolate a fault on a transmission line. Operation of the transmission system also requires equipment telemetry and status information being continuously communicated to the Integrated System Operating Centre (ISOC) through the SONET network. Additionally, the SONET network is used for communicating non-operational data, business data, voice and security information.

The system includes multiplexers, optical amplifiers, digital microwaves and 48V DC backup power supplies (battery and charger systems). The network topology is such that stations are connected in the form of a ring to provide redundant communication links that can stretch hundreds of kilometers across the province.

Hydro One's SONET network has several digital microwave links that were originally deployed where either fibre-based infrastructure was not economically feasible or third-party leased fibre was not available. Over time these digital microwave links have created capacity and bandwidth limitations on a typical ring topology. The associated digital microwave equipment is no longer being manufactured and is technologically obsolete.

Hydro One utilizes asset ESL information as a screening factor for asset replacement assessment, along with hardware obsolescence or level of vendor support, spare equipment availability, performance or failure rates and equipment conditions from preventive maintenance findings. Given the nature of these assets, it is not feasible to assess their physical condition. As such, field deficiency reports, trouble calls and failure incidents provide an indication of the overall condition of the power system telecom assets.

The ESL for most of the digital microwave equipment is 15 years.

Microwave link failures have resulted in multiple power system telecom services being rendered unavailable until repairs were carried out.

Loss of communication channels from SONET equipment failures, including from obsolete microwave links, can result in the removal of power system elements from service and/or power flow constraints on the transmission system (as protection systems dependent on communications cannot protect the equipment and the ISOC can lose visibility into the status of the equipment). In turn, these conditions can have a negative impact on communications availability in support of NERC and NPCC requirements for protection systems, the reliability of the transmission system, and potentially expose Hydro One and its customers to less reliable operating configurations, which can lead to equipment being forcibly removed from service. In addition to the high reliability risk, these legacy microwave links create a bandwidth bottleneck on the SONET network, limiting the full utilization of the capacity of the SONET rings.

3.0 INVESTMENT DESCRIPTION

During the 2023-2027 rate period, approximately 95 km of All Dielectric Self Supporting (ADSS) cable on D6V/D7V (Detweiler x Orangeville) and E8V/E9V (Orangeville x Essa) was replaced with OPGW, while installations for line B22D/B23D were delayed due to the reprioritization of capital expenditures that was required to address increasing demand for non-discretionary and externally-driven investments, coupled with significant cost escalation, as described in TSP Section 2.9. During the 2028-2032 period, this investment will remove microwave systems from SONET Ring 6 and replace them with OPGW on 230 kV line B22D/B23D. The last major microwave links are expected to be removed by Q4 2030.

In addition to the OPGW installation on line B22D/B23D to replace obsolete digital microwave equipment on the SONET Ring 6, the below materiality capital expenditures (see section 5.0) for this investment address other telecommunications needs, consisting of legacy Power Line Carrier systems, legacy telecom network devices, legacy telecom tone equipment, 48 VDC backup power supply systems and operating support systems, which are further discussed in TSP Section 2.2.2.5. These systems and equipment support primary and backup communication systems to provide robust and reliable telecommunications for Hydro One's protection and automation systems and operation of the transmission system.

4.0 OUTCOMES

This investment will replace obsolete microwave links with robust and reliable fibre-optic communication infrastructure that will improve transmission system reliability.

4.1 OEB RRF OUTCOMES

Table 1 below presents anticipated benefits as a result of the investment in accordance with the OEB's Renewed Regulatory Framework.

Table 1 - Outcomes Summary

Customer Focus	• Improve telecommunication reliability and the quality of service provided to customers.
Operational Effectiveness	• Improve reliability of the communications network supporting the transmission system.
Public Policy Responsiveness	• Hydro One is obligated to build and maintain a redundant communication/protection system to ensure that Hydro One meets NERC transmission system performance standards.

5.0 EXPENDITURE PLAN

Table 2 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One – Investment Expenditures[1,2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	15.7	14.8	13.2	7.0	7.2	57.9
Less Removals	0.5	0.4	0.4	0.4	0.4	2.1
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**15.1**	**14.4**	**12.8**	**6.6**	**6.8**	**55.8**

Table 3 includes the prior project total and current project total for the B22D/B23D project, which is the only material investment under this ISD. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The maturity of the project at the time of filing is presented in Table 3, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

[1] Forecast net capital expenditures for the 2028-2032 period include $31.9M of immaterial investments.
[2] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 3 - Hydro One – Material Investment Net Expenditures

Investment Name	Prior Type	Prior Proj. Total[3]	Prior In-Service Year	Type	Proj. Total	In-Service Year
B22D/B23D	P	11.1	2025	P	29.4	2030

Hydro One expects to place the B22D/B23D project in service in 2030 at a project total of $29.4M. Hydro One expects to incur $5.6M prior to 2028 and $23.9M during the 2028-2032 planning period.

The B22D/B23D project was in a preliminary planning phase when the forecast for the 2023-2027 period was established. Subsequently, an additional 35 km of new OPGW was added to the scope, representing a 30% increase. Cost escalations driven by inflation and higher OPGW installation costs have significantly contributed to the variance as well. The project has been deferred due to portfolio reprioritization.

Forecast net capital expenditures for the 2028-2032 period also include $31.9M of immaterial investments. This category of investment increased relative to 2023-2027 actual and forecast expenditures of $21.1M due to the addition of sub-programs to upgrade legacy communications equipment mid-way through the 2023-2027 prior rate period.

The factors influencing the cost of the investment include:

- Planned costs are based on past deployment costs; and
- Coordination and complexity of outages required to replace the SONET communications systems.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred alternative.

[3] "Prior Proj. Total" refers to the Project Total related to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

ALTERNATIVE 1: STATUS QUO: REACTIVE REPAIR OF DIGITAL MICROWAVE EQUIPMENT

This alternative involves repairing microwave links as they fail. Microwave equipment is manufacturer-discontinued, obsolete, and vendor support is no longer available. This results in much longer repair times during which the equipment is out of service and redundancy is lost in that SONET ring. This is an undesirable level of equipment performance as it degrades the reliability of the protection systems in the area.

This alternative has been rejected as Hydro One will be unable to maintain the required performance of the communication networks supporting protection and control systems that rely on these microwave links and would lead to an unacceptable level of risk to system reliability.

ALTERNATIVE 2: PLANNED REPLACEMENT OF MICROWAVE LINKS (RECOMMENDED)

The planned replacement of microwave links is the preferred alternative. This alternative will replace SONET microwave links with OPGW, which will provide robust and reliable communication links for SONET Ring 6. It also allows for coordinated replacement, which facilitates the scheduling of outages to reduce impacts on telecommunication system performance and Hydro One's customers.

Further delay or deferral of this investment may result in loss of protection function and extended transmission line outages due to loss of communications channels, leading to lower reliability of the overall power system.

7.0 EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the project include outage constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, and environmental approvals. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial investment planning phase where all known risks are identified, and a mitigation plan is developed. For example, to address outage constraints, Hydro One develops an outage

coordination plan. This plan aims to minimize the loss of supply to the customer (i.e., switching a customer to an alternative supply). Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages.

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T-SR-13	**TRANSMISSION LINE RENEWAL**
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	68.1	163.8	325.3	307.5	170.8	1,035.4

Summary:

This investment comprises a portfolio of projects that target renewal of transmission line sections that have been confirmed through condition assessment to be in poor condition. The primary trigger of the projects in this investment is confirmation that the conductor, which is the longest life asset of the transmission line, has deteriorated into poor condition. This investment is required to mitigate the safety and reliability risks presented by operating deteriorated transmission lines.

As described in TSP Section 2.9, the combination of increasing demand for non-discretionary and externally driven System Access and System Service investments, and significant cost escalation, required Hydro One to reprioritize its capital portfolio to focus on the highest priority and non-discretionary work during the 2023-2027 period. This reprioritization resulted in the deferral of investment in the majority of transmission line renewal projects presented in Hydro One's last transmission application EB-2021-0110.

Because of these deferrals, the proportion of conductors exhibiting measurable degradation has increased as more assets have deteriorated into the combined fair and poor condition category. As of the end of 2025, 8,375 circuit-km or 30% of the fleet was verified, through testing, to exhibit irreversible degradation. As time progresses there is an increased risk of the failure of multiple circuits under common-cause conditions, which would result in severe system reliability consequences. Degradation does not stabilize or reverse; it continues to worsen.

1.0 OVERVIEW

This investment focuses on replacing conductors and other major transmission line components verified to be in poor condition. Hydro One performs testing to empirically establish the condition of its conductors. When condition assessment results conclusively determine that a conductor is in poor condition, and therefore functionally compromised, a line renewal investment is planned and scheduled.

The electricity transmission system is critical infrastructure, where the overhead transmission conductor is the critical asset responsible for electrically connecting system nodes. Hydro One must sustain this critical infrastructure through managing the health of its in-service overhead conductors. Deterioration of overhead conductors cannot be stopped or reversed. When deterioration is discovered at a tested location, similar levels of deterioration will be present at multiple points along the entire conductor line section of the same vintage and type. In contrast to deterioration, localized conductor damage due to trauma such as a tree fall, lightning strike or vandalism is expected to result in discrete damage that is limited to the immediate area and can be remediated through localized repairs. In contrast, deteriorated conductors can only be remediated through replacement.

This investment consists of thirteen material projects. Each aims to comprehensively sustain overhead transmission line sections through the simultaneous renewal of multiple transmission line components (e.g., overhead conductors, structures, foundations, insulators, and shieldwires), verified to be in poor condition. The primary driver of each investment is to address poor condition overhead conductors that have been verified to be functionally compromised, typically in the form of deteriorated mechanical properties, such as loss of ductility, tensile strength or both. The overhead conductor is the longest life asset of a transmission line where its confirmed deterioration typically signifies that the transmission line as a whole is in poor condition.

Hydro One's overhead conductors are aging and Hydro One must keep pace with asset condition demands. Currently, 3,079 circuit-km or 11% of Hydro One's conductor fleet has been empirically tested and confirmed to be in poor condition. An additional 5,296 circuit-km or 19% of the fleet has been tested to be in fair condition. Fair condition conductors have started to exhibit signs of deterioration, but not to the extent of being functionally

compromised. Together, 8,375 circuit-km or 30% of the fleet is now verified through testing to have, at minimum, commenced irreversible degradation that will continue going forward. In comparison, 26% and 24% of the fleet was recorded to present signs of degradation in EB-2021-0110 and EB-2019-0082 respectively. Overall, this continued accumulation of deteriorating conductors is elevating risk on Hydro One's transmission system.

The significant growth in the population of conductors in fair condition indicates increasing replacement needs and reinforces the urgency of addressing poor condition conductors during the 2028-2032 period. By promptly replacing the conductors that are currently in poor condition, and by doing so before the conductors exhibiting fair condition deteriorate further, Hydro One will maintain its ability to manage the growing population of functionally compromised conductors.

To address immediate sustainment needs and keep pace with the condition of the transmission line fleet, Hydro One expects to place 1,369 circuit-km of renewed transmission lines in service during the 2028-2032 period. This total consists of 1,107 circuit-km associated with 13 material projects and 262 circuit-km associated with below-materiality projects or projects with material expenditures outside the planning period. Including projects that will be partially in-serviced during the 2028-2032 planning period and completed in the subsequent period, the projects included in this investment address 2,402 circuit-km, or 78%, of known poor condition conductors in Hydro One's fleet. Table 1 presents a breakdown of circuit-km addressed under this investment.

Table 1 - Breakdown of Circuit-km Addressed

Grouping of Planned Work	Circuit-km	Known Poor Condition Conductors (%)
Total addressed by projects in this investment	2,402	78%
Total placed in-service during the 2028-2032 period (materiality and below materiality)	**1,369**	**45%**
Total placed in-service beyond the 2028-2032 period (materiality and below materiality)	1,033	34%
Total placed in-service during 2028-2032 period (material investments only)	1,107	36%
Total placed in-service during 2028-2032 period (below materiality investments only)	262	8%

Line renewal projects are prioritized by considering relative condition as well as the consequences of failure to the system and connected customers. Line renewal projects incorporate the renewal of all deteriorated components within the targeted line section, such as insulators, structure and structure components, and shieldwires that have been confirmed to be in poor condition. Given that the conductor has the longest expected service life (ESL) among transmission line assets, when it requires replacement, other line components will likely also have deteriorated to verifiable poor condition and require replacement or renewal as well.

Undertaking conductor renewal and the replacement of other poor condition line components concurrently improves outage efficiency and reduces customer disruptions by allowing Hydro One to complete multiple necessary asset replacements at the same time. This avoids separate interventions that would require additional engineering, construction mobilization, outages, and outage coordination.

2.0 INVESTMENT NEED

Overhead conductors are the single largest and most vulnerable component of the transmission line system. Hydro One has over 28,000 circuit kilometers (circuit-km) of transmission conductors spanning across the diverse geography of Ontario. The overhead conductor is the critical asset responsible for electrically connecting system nodes. Over

99% of Hydro One's transmission system is comprised of overhead lines, with the balance being underground connections. 98% of Hydro One's overhead conductor fleet utilizes Aluminum Conductor Steel Reinforced (ACSR) type conductors, with copper, aluminum and Aluminum Conductor Steel Supported (ACSS) type conductors making up the balance. Overhead conductors are supported by a variety of structures and are interconnected using splices and dead-end connectors, in-span and at dead-end structures respectively.

Hydro One aims to proactively replace its poor condition conductors before they fail to avoid and mitigate significant safety and operational risks. Overhead conductors do not deteriorate consistently or in a predictable manner. The actual service life of each conductor has been observed to vary between 50 and 120 years, and the asset's deterioration rate depends on numerous variables, including manufacturing quality, location, installation orientation, local atmospheric contaminant levels, weather cycles and stringing tension. Hydro One's fleet of overhead conductors is located throughout the province and is subject to varying degrees of exposure to environmental stresses. This affects how fast assets deteriorate. Furthermore, the demand on a conductor's rated mechanical strength is not significant during normal operating conditions, at which time mechanical loading on a conductor can be as low as 15% of rated tensile strength. However, during adverse weather conditions, especially in the presence of ice accumulation, the tension on a conductor can rise to over 90% of rated tensile strength. As such, deteriorated conductors with compromised mechanical strength need to be replaced so that they can survive the next weather event they may be subjected to.

The ACSR conductor, which represents the vast majority of Hydro One's overhead conductor fleet, consists of aluminum strands that surround galvanized steel strands, referred to as the core. The steel strands provide for the majority of the tensile strength of the ACSR conductor. The galvanized coating of the core wears off at varying degrees, depending on weathering or strand movement. Once the exposed steel strands begin to corrode, each strand's material content deteriorates rapidly, thereby resulting in a loss of tensile strength. Deterioration can also take the form of a reduction in ductility or embrittlement. Embrittled conductor strands become more susceptible to breaking when subjected to dynamic forces, which a conductor experiences during storm conditions,

wind-induced vibration, or as a result of galloping (a phenomenon caused by asymmetric aerodynamics, usually caused by ice build-up), which causes the conductor to oscillate (move up and down in the vertical plane). Deterioration in the form of material loss leading to a reduction in tensile strength or in the form of embrittlement compromises a conductor's ability to hold required dynamic mechanical loads. Figure 1 illustrates a dissected ACSR conductor revealing deteriorated core strands with pitting corrosion.

Figure 1: Dissected ACSR Conductor from Circuit B5C Revealing Deteriorated Core Strands with Pitting Corrosion

As of December 2025, Hydro One's conductor fleet has 243 circuit-km of copper conductors remaining, which is the oldest type of conductor in Hydro One's transmission network. This is reduced from 330 circuit-km at the time of Hydro One's last transmission application (EB-2021-0110). These conductors have been exposed to adverse weather conditions longer than other conductor types, and many suffer from damage caused by lightning strikes. Furthermore, many copper conductors cannot be mended and therefore

their failure would result in the need to replace an entire dead-end to dead-end segment (which can span for kilometers), needing extensive resources to perform the repair during an unplanned emergency. Figure 2 illustrates a dissected Hydro One copper conductor revealing a plant fibre core, which cannot be mended.

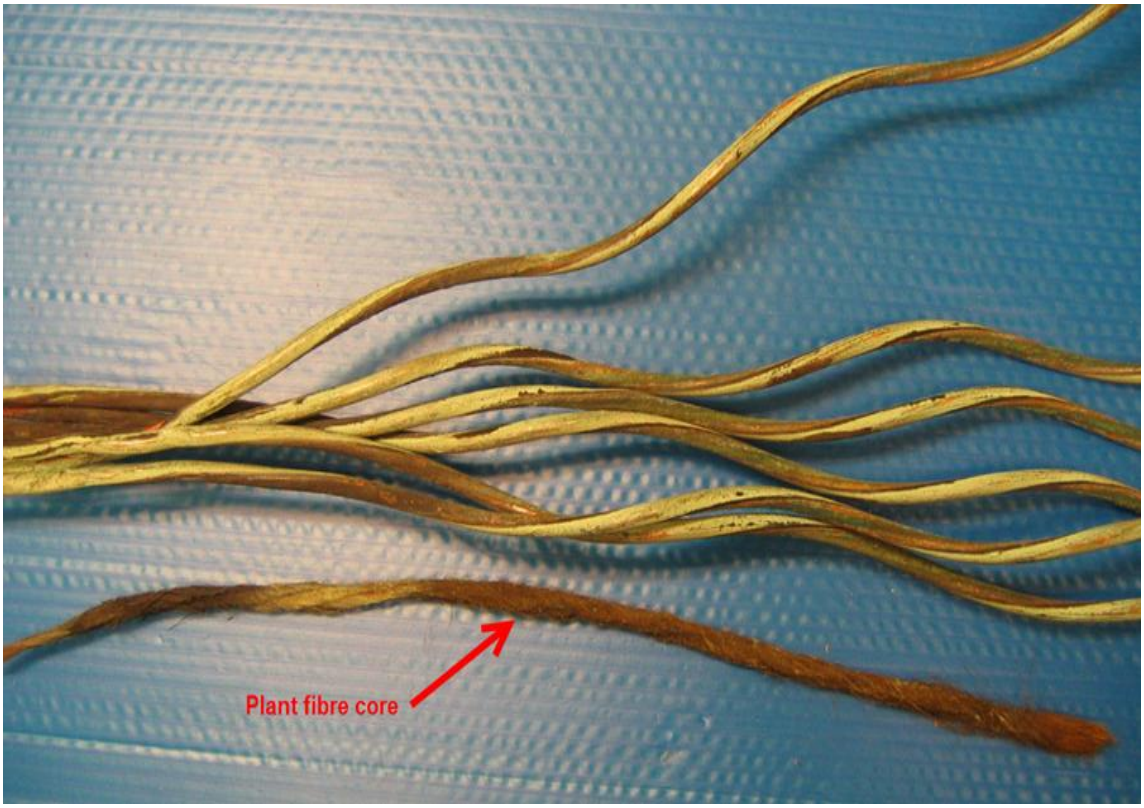

Figure 2: Dissected Copper Conductor

Hydro One determines the condition of its transmission overhead conductors through empirical testing. As outlined in the TSP Section 2.2.4, Hydro One uses Kinectrics' LineVue non-destructive scanning tool, laboratory testing, or a combination of both to establish and verify the condition of its overhead conductors. LineVue scans or short sample testing provide a primary assessment of a line's condition, and in most cases is sufficient to categorize a conductor as being in good, fair or poor condition. Where signs of deterioration are found but condition cannot be clearly established based on test results, a more comprehensive assessment through a long conductor sample test is performed to ensure only poor condition, and therefore confirmed functionally compromised,

conductors are targeted for replacement. As a result of making replacement decisions based on condition assessment, many good condition conductors that have aged beyond ESL are kept in service, and conversely, prematurely deteriorated conductors can be identified and addressed before they fail.

Deterioration of an overhead conductor cannot be stopped or reversed. When deterioration is discovered at a tested location, similar levels of deterioration will be present at multiple points across the entire conductor line section of the same vintage and type. In many cases, deterioration is discovered on both the bare conductor and conductor connectors concurrently. Deterioration of only the conductor connector would be considered a connector issue and not attributed to the deterioration of the overall conductor line section.

To satisfy NERC's reliability standards, most of Hydro One's transmission system has been designed with redundant facilities, such as double circuits. The transmission system is required to be built such that adequate and secure supply is assured over a wide range of conditions so that loss of one or more elements will not result in any violation of thermal and stability limits. As a result of this redundancy, customers of the Hydro One system enjoy a high degree of reliability. A failure of one of the two circuits supplying the delivery point may not impact service to customers because they may continue to receive uninterrupted supply from the multiple circuit connected bus. Even when an initial circuit failure does not interrupt customer supply, it removes system redundancy until the failed system is restored. During that period, an outage impacting the remaining circuit would result in a lengthy delivery point interruption.

Considering the foregoing, reliability statistics are a lagging indicator. They measure interruptions and outages long after condition is established as a causal problem. By the time reliability statistics affected by poor condition assets start to impact delivery points served, service to numerous customers and the overall interconnected system will have been compromised.

Transmission lines are frequently located in publicly accessible areas and pose a significant safety risk, as the failure of a conductor can lead to the overhead strung line

dropping along with its hardware, thereby endangering people and property in proximity of its fall. A typical transmission line span is 300 metres and is strung at an approximate height of 30 metres. At about 1.6 kg/m, a falling conductor span is equivalent to a 480 kg metallic mass falling from a height of 30 metres. Furthermore, in the unlikely case where protection systems fail to operate, a fallen conductor can remain energized, which presents an added danger of electrocution or fire hazard to the surrounding areas. Figure 3 and Figure 4 below provide illustrative examples of the safety risk that a failed conductor poses to the public.

Figure 3: Dropped conductor as a Result of a Polymeric Insulator Failure. Circuit R17T over Highway 10 in the city of Mississauga. The conductor made contact and damaged 2 cars along the southbound lane. The conductor was not energized at the time (protections activated). November 2018.

Figure 4: Dropped Conductor as a Result of a Clamp that Failed Due to Embrittlement. Circuit Q28A over the Queen Elizabeth Way (QEW) near Niagara Falls in March 2020. Sound wall prevented it from going lower on the road.

3.0 INVESTMENT DESCRIPTION

Hydro One currently has 3,079 circuit-km or 11% of its conductor fleet in poor condition, with another 5,296 circuit-km or 19% exhibiting some deterioration, but not to an extent necessitating replacement at this time. Together, the sum of poor and fair condition conductors equates to 8,375 circuit-km or 30% of the Hydro One transmission conductor fleet. Although fair condition conductors do not necessitate immediate replacement, the population of conductors verified to have some level of deterioration continues to increase rate application-over-rate application. Notably, 26% and 24% of the fleet was recorded to show signs of degradation in Hydro One's last transmission application (EB-2021-0110) and EB-2019-0082, respectively. In addition, the average age of the conductor fleet has further increased to 58 years, up from 56 in EB-2021-0110 and 55 in EB-2019-0082. This signifies that the aggregate fleet is aging despite ongoing replacements and grid expansions introducing brand new conductor into the system. Although replacements are triggered by verified condition and not age, on the aggregate, an aged fleet will have a greater population of poor condition conductors versus a younger fleet. Furthermore,

another 7,604 circuit-km or 27% of the fleet has reached an age warranting condition assessment, within which additional deteriorated units may exist. With nearly a third of the transmission conductor fleet verified to have signs of deterioration, continued proactive replacement is crucial to ensure pacing is such that Hydro One is able to manage the volume of immediately required replacements in the years ahead.

Hydro One plans to replace 2,402 circuit-km of conductor or 78% of the known poor condition conductors in the fleet. 1,369 circuit-km of these replacements are planned to be in-serviced during the 2028-2032 planning period. Of the 1,369 circuit-km planned for replacement during 2028-2032, 1,107 circuit-km of replacement work is represented by thirteen material projects that address the subset of poor condition lines that present the greatest safety and reliability risk to the system, and includes consideration of the following:

- All thirteen material projects address circuits with poor condition line components that are located in publicly accessible areas;
- Ten of the thirteen material projects aim to sustain circuits that form part of the North American Electric Reliability Corporation's (NERC) Bulk Electric System (BES), which are subject to mandatory reliability standards and are critical to the reliable operation of the interconnected grid;
- Two investments aim to address poor performing radial lines located in Northern Ontario that serve critical customers such as First Nations communities and large industrial loads, which are often local anchor employers.

Line renewal projects incorporate the replacement of all deteriorated components within the targeted line section, including structures, structure members, shieldwire, and insulators. Components that are in good condition are not renewed under this investment. Given that the conductor has the longest ESL among transmission line assets, coordinating conductor replacement with the replacement of other components is cost effective for sustaining an overhead power line. In general, when the conductor requires replacement, it is common for other line components to have also deteriorated to poor condition and require replacement or refurbishment as well.

This investment portfolio will help mitigate the severe safety consequences that could arise from a failed or falling conductor and avoid unacceptable system and customer exposure to the elevated operating risks arising from transmission circuit outages.

The scope for each material project is described in Appendix A.

4.0 OUTCOMES

The comprehensive renewal of poor condition line sections will alleviate the safety and operational risks associated with operating equipment in poor condition; ensure required sustainment work is performed with minimal impact to local environments and landowners; maintain long-term reliability of connected stations and transmission customers; and reduce constraints on generation resources.

4.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 2 - Outcomes Summary

Customer Focus	• The renewal of poor condition overhead transmission line sections decreases the likelihood of their failure. Decreased likelihood of failure results in a decreased likelihood of an outage to connected customers. • Renewal of transmission line sections in poor condition decreases that line section's likelihood of failure. This reduces the likelihood of a conductor dropping and potentially causing injury to the public or employees, damaging property or damaging local environment (fire caused by dropped energized conductor).
Operational Effectiveness	• Operating a line section with components that have deteriorated to poor condition subjects that circuit to an increased likelihood of failure, which directly threatens reliable operation of the system. Line renewal will alleviate this threat. • Reduces line losses where applicable.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence and the TSC to maintain the reliability and integrity of its transmission system.

5.0 EXPENDITURE PLAN

Table 3 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 3 - Hydro One - Investment Expenditures[1,2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	80.7	178.0	353.6	334.2	185.6	1,132.1
Less Removals	12.6	14.2	28.3	26.7	14.8	96.7
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	68.1	163.8	325.3	307.5	170.8	**1,035.4**

As described in TSP Section 2.9, Hydro One was required to reprioritize capital expenditures due to increasing demand for non-discretionary and externally-driven investments, coupled with significant cost escalation. This reprioritization resulted in the deferral of transmission line renewal projects presented in Hydro One's last transmission application EB-2021-0110 beyond the 2023-2027 period. Of the 1,571 circuit-km planned for in-servicing during 2023-2027 in EB-2021-0110, 155 circuit-km were in-serviced between 2023 and 2025 inclusive. These investments were situated in the northern Ontario, Hamilton, Niagara, Kingston and Ottawa areas.

Additional information for each investment with material capital expenditures in the 2028-2032 rate period is included in Appendices A and B. In the 2028-2032 planning period, Hydro One expects total project costs for certain investments to be higher than the corresponding forecasts reflected in Hydro One's prior transmission application. These increases primarily reflect the combined effects of capital reprioritization and project deferral, inflationary pressures, further development of project scope and estimates, and project-specific execution requirements. The relative contribution of these factors varies by project. The principal portfolio-level and project-specific drivers are described below.

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] Forecast net capital expenditures for the 2028-2032 period include $27.0M of immaterial investments.

- Capital reprioritization during the 2023-2027 period resulted in lower expenditures than planned during the 2023-2027 period.
- Higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historic material cost escalation trends are described in SPF Section 1.8.3, including transmission and distribution poles and conductors, cables and wires, which have increased by 45% and 65%, respectively, on average since 2020.

Partially offsetting these increases, forecast total project costs have been reduced for certain projects, as shown in Table B1 of Appendix B. For example, concurrent development expected for the E8V/E9V (T-SR-13.07), and B5QK (T-SR-13.11) line projects has reduced the scope of sustainment work required, resulting in forecast cost reductions of $36.9M and $11.1M, respectively. In addition, the forecast project total for A4L (T-SR-13.12) has been reduced to reflect cost savings associated with the outage enabled by the Greenstone Transmission Line project (see ISD T-SS-10). The Greenstone project will allow the A4L line to be taken off radial configuration, making an outage easier to obtain and execute, thereby reducing the cost of completing the renewal work.

The factors influencing the cost of the investment include:

- In the latter years of the 2028-2032 planning period, higher voltage and BES circuits are replaced. These circuits consist of larger steel structure facilities, which result in increased line renewal costs.
- In each investment, the number of assets replaced (i.e., structures replaced or refurbished, insulators replaced or km of shieldwire replaced) influences the cost of the investment, with consideration of:
    - Higher voltage circuits are more costly from a material perspective as is the overall installed cost due to required clearances for high voltage equipment.
- Geographical location of the investment

  - Investments located in northern Ontario are usually remote and require larger access costs.
  - The geography of investment also impacts the length of the construction season, as winter conditions arrive sooner in Northern Ontario.
- The complexity of project staging and outages required to facilitate work
  - The more complex the investment, the more inter-connections, and the more outages required will increase the cost of the investment.
- Whether the investment is a greenfield replacement or in-situ replacement requiring complex contingency planning
  - In some cases existing right-of-way or land right agreements are not sufficient to execute the line renewal in-situ. This can add additional real estate and vegetation clearing costs to the investment.
- Community impacted by the investment:
  - Line renewals take place in locations occupied by the public and as such can impact many interfacing stakeholders including property owners, other utilities, and indigenous communities. As such, interfacing costs can vary from investment to investment.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred option.

ALTERNATIVE 1: REACTIVE COMPONENT SUSTAINMENT

Reactive sustainment of overhead transmission lines would involve operating overhead conductors, structures, foundations, insulators, and shieldwires to failure, where these components are only sustained after failing. Hydro One's overhead transmission lines are strung in publicly accessible locations, where broken overhead components can disconnect from the overhead line and fall, posing public and employee safety risks. Failure of a structure can also result in dropping line components to the right-of-way below, which can include roadways, waterways and populated areas. For this reason, Hydro One cannot run its transmission lines to failure, as the consequence and therefore risk to public safety is unacceptable. Furthermore, transmission lines are critical to the integrity of the

transmission system, where allowing components to fail would result in a significant deterioration in reliability. Hydro One has rejected this alternative for the following reasons:

- Although poor-condition assets have an elevated likelihood of failure, the timing and location of a failure cannot be predicted. Reactive sustainment would therefore require unplanned mitigation and emergency resource deployment. Where lines are not redundant, unplanned mitigation of failures can be prolonged and result in extended equipment and customer outages, negatively affecting the Transmission System Average Interruption Duration Index (SAIDI) and Transmission System Average Interruption Frequency Index (SAIFI) performance.
- Mitigating unexpected failures will lead to increased environmental risk due to not being able to comprehensively plan for the environmental impact of the required construction activities for line restoration.
- Unexpected failures would lead to increased safety risk to both the public and work crews due to the possibility of a failure being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would result in continual reprioritization of planned work and inefficient redeployment of resources.
- This alternative limits the ability to account for future requirements and has a high risk of re-work and future additional costs.
- This approach is likely to increase operating and maintenance costs, decrease equipment performance and increase safety risks to personnel on site.

ALTERNATIVE 2: PLANNED LINE SECTION RENEWAL (RECOMMENDED)

Planned replacement of line sections is the recommended option for this investment.

Unlike reactive replacements, planned line section renewal allows the work to be completed through coordinated outage plans, reducing the number of equipment outages and mitigating the safety and reliability risks associated with continued deterioration or in-service failure.

During the development of a line renewal investment, Hydro One considers other line components along the section for replacement in addition to the conductors that have

been confirmed to be in poor condition, such as structures, structure members, shieldwire, and insulators. Components confirmed to be in poor condition are included in the project scope where appropriate. Completing the renewal of multiple poor condition assets concurrently enables improved outage and execution efficiency, avoids repeated construction mobilization, and reduces disruption to landowners and circuit operations compared with completing the work through separate interventions.

Planned renewal also provides an opportunity to assess whether operational improvements or upgrades can be incorporated efficiently while the line section is being renewed. This may include addressing current or future system and customer needs.

This alternative is recommended because it addresses the identified poor-condition assets before failure while allowing related work to be coordinated. Relative to reactive replacement, it provides a more comprehensive approach to managing safety and reliability risks, outage requirements, execution costs and stakeholder impacts.

7.0 EXECUTION RISK AND MITIGATION

As described in TSP Section 2.11, Hydro One follows a Transmission Capital Project Delivery Model, throughout which project risks are identified and mitigation plans are implemented. Risks that can impact the completion of transmission line renewal include:

- Outage constraints:
  - Planned outages are required to replace assets. Outages may include individual line sections, or multiple line sections on different circuits should clearances for safe work not be sufficient.
  - Outages must be planned and coordinated to minimize the impact to customers and system redundancy.
- Construction execution challenges:
  - Existing line structures and connecting hardware may require retrofits to accommodate new assets as line design and equipment standards have evolved. In some cases, structures need to be modified or fully replaced to accommodate required clearances.
- Customer and interfacing community coordination:

- Hydro One makes best efforts to coordinate with customers and community stakeholders to minimize their impact, including minimizing service disruptions (outages) and public space occupation by construction crews and supporting laydown areas.

- Real estate requirements:
  - Expansion and new land may be required when the existing right-of-way cannot accommodate the required work.
- Procurement challenges:
  - Major equipment procurement lead times.

APPENDIX A – DESCRIPTION OF FORECAST INVESTMENTS

This Appendix describes each material investment and forecast capital expenditures for the 2028-2032 planning period.

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
T-SR-13.01	T22C and T28C 230kV Part of NERC's Bulk Electric System (BES)	• This project renews a total of 228 km of 230kV circuits T22C and T28C between Chats Falls SS and Clarington TS, and between Clarington TS and Duffin JCT. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1930s. • Circuits T22C and T28C span between the city of Ottawa and Oshawa in Eastern Ontario. These circuits supply Elexicon Energy Inc. and Hydro One Distribution connected communities.	228	228	227.1	227.1
T-SR-13.02	T25B 230kV	• This project renews a total of 120 km of 230kV circuit T25B between Pancake JCT and Clarington TS.	0	120	87.9	112.1

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
		• The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • This line section was originally constructed in the 1920s. • Circuit T25B spans between the cities of Belleville and Oshawa in Eastern Ontario. The circuit is publicly accessible and services several customers including Elexicon Energy Inc. and local Hydro One Distribution connected communities. • Circuit T25B crosses several major roadways including highways 35, 62 & 115.				
T-SR-13.03	E1C 115kV	• This project renews a total of 162 km of 115kV circuit E1C within two non-adjacent line sections: 1. Ear Falls TS X Slate Falls DS (148 km) 2. Etruscan JCT X Crow River DS (14 km) • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew	162	162	62.9	67.9

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
		verified deteriorated shieldwire, insulators and wood pole structures. • These line sections were originally constructed in the 1930s. • Circuit E1C is a poor performing radial line located north of the city of Dryden in Northwestern Ontario. The circuit is publicly accessible and services several customers including a generator, a lumber company and local Hydro One Distribution connected communities.				
T-SR-13.04	D2H, D3H, D6T and D4 115kV Part of NERC's Bulk Electric System (BES)	• This project renews a total of 183 km of 115kV circuits D2H, D3H, D6T and D4 between Hunta SS and Abitibi Canyon SS. • The investment is needed to address the verified poor condition ACSR conductors along these lines, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1930s. • Circuits D2H, D3H, D6T and D4 are located north of the city of Timmins in Northeastern Ontario. The circuits are publicly accessible and serve several customers including	183	183	183.7	189.2

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
		generators and local Hydro One Distribution connected communities. • Circuit D2H and D3H cross several major roadways including highway 634.				
T-SR-13.05	T33E 230kV Part of NERC's Bulk Electric System (BES)	• This project renews a total of 252 km of 230kV circuit T33E between Almonte TS and Oshawa North JCT. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated tensile strength. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1930s. • Circuit T33E spans between the city of Oshawa and Ottawa in Eastern Ontario. The circuit is publicly accessible and services local Hydro One Distribution connected communities. • Circuit T33E crosses several major rail and roadways including highways 7, 35, 41, 62 and 115.	252	252	230.2	230.2
T-SR-13.06	Q2AH and A8G 115kV	• This project renews a total of 22 km of 115kV circuits Q2AH and A8G	22	22	11.5	11.6

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
		between Rosedene JCT and St. Anns JCT. • The investment is needed to address the obsolete copper conductors along this line. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1910s. • Circuits Q2AH and A8G are located near the city of Niagara Falls in southern Ontario. The circuit is publicly accessible and services several customers including Niagara Peninsula Energy Inc., Alectra Inc., and local Hydro One Distribution connected communities.				
T-SR-13.07	E8V and E9V 230kV Part of NERC's Bulk Electric System (BES)	• This project renews a total of 112 km of 230kV circuits E8V and E9V between Orangeville TS and Essa JCT. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1950s.	112	112	25.0	25.0

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
		• Circuits E8V and E9V are located south of the city of Barrie in Central Ontario. The circuit is publicly accessible and services local Hydro One Distribution connected communities. • Circuits E8V and E9V cross several major rail and roadways including County Road 56.				
T-SR-13.08	C27P 230kV Part of NERC's Bulk Electric System (BES)	• This project renews a total of 128 km of 230kV circuit C27P between Galetta JCT and Bannockburn JCT. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1930s. • Circuit C27P is located north of the city of Belleville in Eastern Ontario. The circuit is publicly accessible and services several customers including Ontario Power Generation Inc. and local Hydro One Distribution connected communities.	128	128	59.1	59.1

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
T-SR-13.09	S2N 115kV	• This project renews a total of 54 km of 115kV circuit S2N between Sarnia Scott TS and Adelaide JCT. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated tensile strength. This investment will also renew verified deteriorated shieldwire, insulators and wood pole structures. • These line sections were originally constructed in the 1940s. • Circuit S2N is located in the city of Sarnia in Southwest Ontario. The circuit is publicly accessible and services several customers including Entegrus Powerlines Inc., gas and petro-chemical companies, and local Hydro One Distribution connected communities. • Circuit S2N crosses several major rail and roadways including Mandaumin Road, Kimball Road, Oil Heritage Road and Plank Road.	54	54	22.6	22.7
T-SR-13.10	A4H and A5H 115kV Part of NERC's Bulk Electric System (BES)	• This project renews a total of 47 km of 115kV circuits A4H and A5H between A.P. Tunis JCT and Fournier JCT. • The investment is needed to address the verified poor condition	47	47	24.6	24.8

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
		ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1930s. • Circuits A4H and A5H are located north of the city of Timmins in Northeastern Ontario. The circuit is publicly accessible and services several customers including industrial customers, generators and local Hydro One Distribution connected communities.				
T-SR-13.11	B5QK 115kV Part of NERC's Bulk Electric System (BES)	• This project renews a total of 60 km of 115kV circuit B5QK between Barrett Chute #2 JCT and Sharbot JCT. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1950s. • Circuit B5QK is located north of the city of Kingston in Eastern Ontario. The circuit is publicly accessible	60	60	21.1	21.0

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
		and services several customers including Kingston Hydro Corp. and local Hydro One Distribution connected communities.				
T-SR-13.12	A4L 115kV Part of NERC's Bulk Electric System (BES)	• This project renews a total of 79 km of 115kV circuit A4L between Beardmore JCT/DS #2 x Long Lac TS. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and wood pole structures. • These line sections were originally constructed in the 1930s. • Circuit A4L is a poor performing radial line located east of Lake Nipigon in Northwestern Ontario. The circuit is publicly accessible and services several customers including local Hydro One Distribution connected communities. • Circuit A4L crosses several major rail and roadways including highway 11.	79	79	35.2	35.6
T-SR-13.13	H1L, H3L, H6LC and H8LC 115 kV	• This project renews a total of 8 km of 115kV circuits H1L, H3L, H6LC and H8LC between Bloor St. JCT. and Leaside JCT.	8	8	17.3	17.5

ISD Ref.	Circuit	Scope, Need and Outcome	28-32 Total Units Replaced	Project Total Units Replaced	28-32 Net Total	Project Net Total
			Circuit-km	Circuit-km	($M)	($M)
	Part of NERC's Bulk Electric System (BES)	• The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. This investment will also renew verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1950s. • Circuits H1L, H3L, H6LC and H8LC are located in the city of Toronto. The circuit is publicly accessible and services several customers including Toronto Hydro Electric System Limited.				
	Total		**1,107**	**1,227**	**-**	**-**

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

The investments proposed in this ISD are complex and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.11. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project, the in-service year and the project total estimates for the 2023-2027 and 2028-2032 rate periods. Project maturity is defined by the following project phases:

- Execution (E), which reflects fully approved project work;
- Planning and Definition (P), which reflects non-execution work, regardless of level of upfront development; and
- Complete (C), which reflects that the project has been placed in service

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in the table below in reference to project total variances and overall project schedule variances.

Variance explanations are provided in Section 5.0 above.

1

Table B1 - Hydro One – Investment Costs ($M)

ISD Ref.	Line Name	Net Capital Investment								Project Forecast			Prior Project Forecast[3]			
		Actual Pre-2023	Act/Fcst[4] 2023-2027	2028	2029	2030	2031	2032	28-32 Total	Phase	Proj. Total	In-Service Year	ISD Ref.	Prior Phase	Prior Proj. Total	Prior In Service Year
T-SR-13.01	T22C and T28C 230 kV	-	0.0	0.8	5.5	73.6	73.6	73.6	227.1	P	227.1	2032	T-SR-13.1	P	88.1	2030
T-SR-13.02	T25B 230 kV	-	0.0	0.7	8.1	25.9	26.4	26.9	87.9	P	112.1	2033	T-SR-13.2	P	81.1	2027
T-SR-13.03	E1C 115 kV	4.8	0.2	3.0	20.3	20.7	19.0	0.0	62.9	P	67.9	2031	T-SR-13.3	P	55.2	2026
T-SR-13.04	D2H, D3H, D6T and D4 115 kV	2.4	3.1	49.7	50.7	51.7	31.6	0.0	183.7	P	189.2	2031	T-SR-13.4	P	96.3	2026
T-SR-13.05	T33E 230 kV	-	0.0	5.4	50.7	56.9	58.0	59.2	230.2	P	230.2	2032	T-SR-13.5	P	118.3	2027
T-SR-13.06	Q2AH and A8G 115 kV	-	0.0	1.1	3.9	4.8	1.8	0.0	11.5	P	11.6	2031	T-SR-13.6	P	9.7	2025
T-SR-13.07	E8V and E9V 230 kV	-	0.0	0.4	0.8	11.9	11.9	0.0	25.0	P	25.0	2031	T-SR-13.7	P	61.9	2027
T-SR-13.08	C27P 230 kV	-	0.0	0.6	4.5	27.0	27.0	0.0	59.1	P	59.1	2031	T-SR-13.16	P	86.5	2029
T-SR-13.09	S2N 115 kV	-	0.0	0.6	7.4	9.2	5.5	0.0	22.6	P	22.7	2031	T-SR-13.15	P	29.6	2027
T-SR-13.10	A4H and A5H 115 kV	0.2	0.0	0.5	2.0	8.3	8.4	5.4	24.6	P	24.8	2032	T-SR-13.10	P	20.7	2027

[3] "Prior Project Forecast" refers to the forecast project total and in-service date when Hydro One revised the capital 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.

ISD Ref.	Line Name	Net Capital Investment								Project Forecast			Prior Project Forecast[3]			
		Actual Pre-2023	Act/Fcst[4] 2023-2027	2028	2029	2030	2031	2032	28-32 Total	Phase	Proj. Total	In-Service Year	ISD Ref.	Prior Phase	Prior Proj. Total	Prior In Service Year
T-SR-13.11	B5QK 115 kV	-	0.0	0.4	0.7	4.1	15.8	0.0	21.1	P	21.0	2031	T-SR-13.11	P	32.1	2028
T-SR-13.12	A4L 115 kV	0.4	0.0	0.8	3.0	15.5	15.8	0.0	35.2	P	35.6	2031	T-SR-13.12	P	49.1	2025
T-SR-13.13	H1L, H3L, H6LC and H8LC 115 kV	0.1	0.0	0.7	2.0	8.3	6.3	0.0	17.3	P	17.5	2031	-	P	6.0	2025
-	M6/7E	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	P	26.8	2026
-	D6	34.7	36.7	1.3	0.0	0.0	0.0	0.0	1.3	E	72.7	2028	-	E	42.8	2025
-	N5K	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	P	34.8	2027
-	K4	0.8	11.5	0.0	0.0	0.0	0.0	0.0	0.0	C	12.5	2024	-	P	6.6	2024

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T-SR-14	MOBILE RADIO SYSTEM REPLACEMENT
Primary Trigger:	Obsolescence/Operational Safety
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	15.4	21.0	12.8	8.0	0.0	57.2

Summary:

This investment involves the design, procurement and implementation of a new digital Provincial Mobile Radio (PMR) system to replace the existing ageing, failing and obsolete analog provincial Land Mobile Radio (LMR) system. Availability of reliable two-way communications for field crews is an operational requirement for Hydro One. The primary trigger of the investment is to replace obsolete infrastructure and outdated technology throughout the province using an up-to-date and modern communication network. The current LMR has been discontinued by the manufacturer, meaning that there is limited to no vendor support, and strategic spares have diminished.

For the 2023-2027 rate period, this investment had a total project budget of $32.1M and an expected in-service date of December 2026. The project budget has been subsequently updated to $63.4M, reflecting Hydro One's plan to proceed with a hybrid satellite/cellular/radio solution. This approach addresses risks identified with unavailability of frequencies and higher infrastructure deployment costs across the province and is more cost effective than alternatives as identified through a 2024 Request for Information (RFI) to assess available technology and high-level pricing from the market.

Analysis of the RFI showed that new LMR based system costs for new infrastructure could be between $105.0M and $130.0M (based on number of repeater sites needed), with ongoing risks related to the LMR approach due to unavailability of radio licenses in southern Ontario, the need for additional radio base stations and the need for additional high speed backhaul infrastructure. The analysis also identified that a satellite/cellular

hybrid system of comparable size would have significantly lower capital cost, partially offset by monthly subscription fees for each end device.

Deployment of the new system is expected to begin in 2027 and be fully implemented by Q4 2031. The current funding for the 2028-2032 planning period is to complete implementation of a hybrid satellite/cellular/radio solution to replace the current PMR system.

1.0 OVERVIEW

This investment involves implementing a solution to replace the existing provincial mobile radio system. The existing radio technology used for Hydro One's PMR system is obsolete and requires replacement as there is very limited supply of strategic spares remaining and no new units or spares available from manufacturers. The planned mobile radio replacement project addresses concerns regarding the obsolescence of the existing technology, the commercial unavailability of radio equipment in the 49 MHz frequency band (which is what Hydro One's current system is based on) and the condition of the deployed equipment. The investment will implement a new technology solution to continue providing dispatch capability between control center and field staff as well as communications among field crews when maintaining and restoring transmission system assets. Hydro One intends to proceed with a hybrid satellite/cellular/radio technology solution.

2.0 INVESTMENT NEED

Hydro One owns and operates a private mobile radio system that is used for two-way voice communication between control centers and field crews, and among field crews. This system is used by forestry and lines crews during restoration efforts, emergency operations and during day-to-day construction and maintenance work. The mobile radio system provides coverage that exceeds the cellular coverage in remote areas and is often the only means of communications in these areas.

The existing radio technology Hydro One uses for its mobile radio system is manufacturer-discontinued and obsolete with no vendor support. With limited strategic spares left, Hydro One will be unable to economically restore radio communications upon failure of equipment. This would render voice communication unavailable for field staff and control centers, especially in parts of the province where there is no cellular coverage. As a result, Hydro One will be challenged to maintain transmission system equipment and restore power in remote areas in a safe and timely manner resulting in longer than expected outages.

The concerns with equipment obsolescence, the commercial unavailability of radio equipment in the 49 MHz frequency band and condition of the currently deployed

equipment necessitate replacing the current provincial radio system. Considering the foregoing, a new hybrid satellite/cellular/radio system solution was selected to provide enhanced operational communications between control centres and field staff.

3.0 INVESTMENT DESCRIPTION

This investment will provide a hybrid satellite/cellular/radio solution to replace the existing PMR system. In order to utilize existing satellites in orbit, integrated satellite receiver and cellular modem with voice capability will be installed in each vehicle. Satellite and cellular subscription, with pooled data plans for the entire fleet for optimized OM&A expenditure, will be required. Unlike the LMR based solution, no further backhaul infrastructure investment will be required.

The investment is paced to allow the new technological solution and the ensuing system to be fully field trialed, tested and tailored to Hydro One's environment prior to full rollout. Multi-year deployment starting in 2027 will smooth the transition to the new system until expected completion in 2031, while utilizing the existing system to its full extent. It is expected that the new system will be fully implemented by Q4 2031.

4.0 OUTCOMES

By replacing the existing PMR system, Hydro One will be able to continue providing radio communication between control centers and field crews, while maintaining efficiency and safety during restoration efforts, emergencies and scheduled construction and repair work. This in turn will allow Hydro One to keep power outage durations to a minimum to the benefit of customers, in a safe and timely manner.

4.1 OEB RRF OUTCOMES

Table 1 presents the benefits anticipated as a result of the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Maintain Hydro One's ability to restore transmission equipment in remote areas in a timely manner to minimize impacts on the system and customers.
Operational Effectiveness	• Continue to minimize equipment outage durations and power restoration times, while enhancing employee safety during field operations.

5.0 EXPENDITURE PLAN

Table 2 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period. No investment costs are forecast beyond 2031.

Table 2 - Hydro One – Investment Expenditures[1,2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	15.8	21.8	13.0	8.0	0.0	58.6
Less Removals	0.4	0.8	0.2	0.0	0.0	1.4
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**15.4**	**21.0**	**12.8**	**8.0**	**0.0**	**57.2**

Table 3 includes the prior project total and current project total for the Mobile Radio System Replacement project, which is the only material investment under this ISD. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The maturity of the project at the time of filing is presented in Table 3 below, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

[1] Forecast net capital expenditures for the 2028-2032 period include $1.5M of immaterial investments.
[2] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 3 - Hydro One – Material Investment Net Expenditures

Investment Name	Prior Type	Prior Proj. Total[3]	Prior In-Service Year	Type	Proj. Total	In-Service Year
Mobile Radio Replacement System	P	32.1	2026	P	63.4	2031

Following completion and evaluation of the RFP/RFQ, the project will be awarded for implementation upon validation in Hydro One's field environment. The project is planned for completion by Q4 2031, and lower expenditures are expected in that final year as the project wraps up.

For the 2028-2032 planning period, Hydro One expects the project total for the Mobile Radio System Replacement project to be $63.4M, which is $31.3M higher than the prior project total from the 2023-2027 prior rate period. The increase reflects estimated costs specific to the technological solution identified in the early steps of the project and information obtained from analysis of the RFI, as described above.

Prior to 2028, Hydro One plans to complete the evaluation of the satellite technology, issue an RFP/RFQ for the replacement solution and start phased deployments of the hybrid satellite/cellular/radio-based solution. Hydro One expects to incur $7.7M prior to 2028, which will largely be concentrated in 2027 for the initial system deployment. During the 2028-2032 planning period, Hydro One expects to incur $55.7M for this project.

In addition, expenditures under this investment include $2.4M and $1.5M for immaterial investments during the 2023-2027 and 2028-2032 periods, respectively.

[3] "Prior Proj. Total" refers to the project total related to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred alternative.

ALTERNATIVE 1: STATUS QUO: MAINTAINING THE EXISTING SYSTEM

This alternative is not viable because Hydro One cannot maintain the existing PMR system in its current state. As strategic radio spares have diminished and there is limited to no vendor support, Hydro One is currently unable to effectively restore failed radio equipment in fleet trucks and radio base stations. This situation may render voice communication unavailable for field staff and control centers. As a result, Hydro One could be challenged to maintain transmission system equipment and/or restore power in remote areas in a safe and timely manner resulting in longer than expected outages.

ALTERNATIVE 2: REPLACE LEGACY MOBILE RADIO SYSTEM WITH LAND MOBILE RADIO-BASED SOLUTION

This alternative is not preferred due to the risks associated with unavailability of radio frequencies required for the solution and high infrastructure costs, which are expected to be in the range of $105.0M to $130.0M (based on number of repeater sites needed). This traditional LMR-based solution requires securing additional radio frequency licenses, radio base station equipment and locations, and deployment of high-speed backhaul communications to the base station locations. This alternative also necessitates continued maintenance of new and existing radio base stations, towers and shelters, including those at hard-to-reach geographical locations.

ALTERNATIVE 3: REPLACE LEGACY MOBILE RADIO SYSTEM WITH HYBRID SATELLITE/CELLULAR/RADIO-BASED SOLUTION (RECOMMENDED)

This is the preferred alternative. This alternative involves procuring a fully integrated hybrid satellite/cellular/radio-based solution that meets the communication needs of the control centre dispatch and field crews using commercially available and supported technology.

The benefits of this preferred alternative are:

- Ability to provide reliable voice communication coverage throughout the Hydro One service territory.

- Minimization of end-to-end voice delay.
- Minimization of backhaul infrastructure required to be built by Hydro One.
- Dependability and reliability of the solution, due to redundancy provided by the hybrid satellite/cellular/radio approach.
- The ease of use, operation and uniformity of solution across all Hydro One work groups/centers.
- Industry trends suggest this preferred solution involves future-proofed technology.

The solution proposed must apply to all field work centers and crews uniformly across the province and allow for varying implementations based on geography in order to facilitate seamless work-site travel and system administration. This approach allows Hydro One to continue to provide voice communications between field staff and control centers and among field crews during restoration efforts, emergency operations as well as day-to-day construction and maintenance work.

7.0 EXECUTION RISK AND MITIGATION

The evaluation trial of the hybrid satellite/cellular/radio solution in Hydro One's service territory is designed to further ensure its suitability across all Hydro One users and work groups.

It is judicious for Hydro One to ultimately commit to a solution that meets technical and business requirements, while minimizing Hydro One owned or leased new infrastructure.

T-SR-15	**TRANSMISSION LINE EMERGENCY RESTORATION**
Primary Trigger:	Asset Failure or High Risk of Failure
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	-	11.4	11.6	11.9	12.1	12.4	59.4
HOSSM[1]	1.8	0.7	0.8	0.8	0.8	0.8	5.7

Summary:

This investment involves the emergency replacement of transmission line components either because they have failed or because they have been identified as being in imminent danger of failure. The primary trigger for the investment is asset failure or risk of failure requiring corrective repairs on transmission lines assets. The investment is expected to minimize the impact on reliability and safety while ensuring compliance with the Transmission System Code (TSC).

[1] See Appendix C for a description of HOSSM's transmission line emergency replacement program.

1.0 OVERVIEW

The Transmission Lines Emergency Replacement program is reactive in nature, mainly to provide an immediate response to an emergency or to prevent or minimize the effects of an emergency. This investment funds the emergency replacement of transmission line components that have failed or that have been identified to be in imminent danger of failure.

A failed or deficient transmission line component may have an impact on the transmission system that varies from minor to significant. It poses a safety risk, as well as a power delivery risk which can impact regional load flow limits and customer operations. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards imposed by the TSC. This investment program ensures that Hydro One continues to comply with its regulatory commitments and legal obligations to mitigate safety, system reliability, and environmental risks that an unforeseen failure might cause.

2.0 INVESTMENT NEED

Under the TSC, a transmitter is required to take action during an emergency to ensure public safety and to safeguard life, property and the environment as well as to protect the stability, reliability, and integrity of its transmission facilities.

Hydro One's transmission system extends throughout most of the province and operates in diverse geographic and climatic conditions. Hydro One operates transmission lines primarily at 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV. These lines are used to transmit electric power to connected commercial and industrial customers, as well as to Local Distribution Companies (LDC) who in turn distribute the power to their end-use customers. The majority of Hydro One's transmission system is composed of overhead lines, with a small portion of underground cables.

The major components of the overhead transmission lines system include conductors, steel and wood pole structures, foundations, insulators, shieldwire, switches, and line hardware. Transmission line components may fail or be at risk of imminent failure due to weather events, component deterioration, design deficiencies, vandalism, or accidents caused by public activity. Since almost all transmission lines are located within publicly

accessible space, the primary focus of this investment is to ensure public and employee safety.

This investment is also focused on maintaining reliability and minimizing power delivery impacts. If any of the major transmission line components fail or are in imminent danger of failure, Hydro One must replace the asset as soon as possible, to ensure public and employee safety and to maintain the integrity and reliability of the transmission system. When a transmission line component fails, the impact varies depending on where the component is and the redundancy level of the electrical configuration. In some cases, failed transmission line components may fall onto public areas such as road crossings and public or private properties, which could jeopardize public or employee safety, impact power delivery, and result in customer interruptions.

3.0 INVESTMENT DESCRIPTION

An emergency is defined as a situation where a structure or component has failed or is at risk of imminent failure, and where the failure could result in a serious public or employee safety hazard, circuit interruption, and system reliability impact.

This investment funds emergency replacement of failed or defective transmission line components, such as wood structures, cross-arms, towers, insulators, conductor, shieldwire and hardware. Some of the main reasons for transmission line component failures include weather conditions (i.e. lightning), severe weather events (i.e. tornado), deterioration, design deficiencies, vandalism, and accidents caused by public activity. In addition to structures and/or components that have failed as shown in Figures 1 to 4 below, Hydro One must also respond to structures and components at risk of imminent failure that are identified through condition/preventive patrols. An example would be a wooden cross-arm or structure that has been damaged by lightning and poses a risk of failure. Such repairs are also considered an emergency.

Figure 1: T22C Tower 520 steel members bent and broken due to shifting foundation

Figure 2: B501M Connector Failure on 500kV Dead-end Tower

Figure 3: L24A Twr 170 and 171 collapsed due to severe storm

Figure 4: D3H Broken Cross Arm and Deteriorated Poles

This investment involves the emergency replacement of transmission line components either because they failed or because they have been identified as being in imminent danger of failure. Below are the three largest categories of emergency replacements during the 2023-2025 period:

Category	Number of Replacements
Insulators	51
Wood Pole Arm	12
Full Structure	204

4.0 OUTCOMES

This investment aims to:

- Mitigate safety risks by replacing failed overhead line components or components that are at risk of imminent failure.

- Maintain reliability of the transmission system by ensuring timely replacement of failed overhead line components or components that are at risk of imminent failure.
- Satisfy Hydro One's commitments and obligations under the TSC.

4.1 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 - Outcomes Summary

Customer Focus	• Improve customer satisfaction by minimizing interruptions and providing timely power restoration to customers.
Operational Effectiveness	• Minimize public/safety risk and system reliability impact by repairing and/or replacing assets that failed or are at risk of imminent failure.
Public Policy Responsiveness	• Comply with TSC obligations by providing safe and reliable electricity to Ontario electric consumers.

5.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One – Investment Expenditures[2]

($M)	2028	2029	2030	2031	2032	Total 2028-32
Gross Capital Expenditures	12.9	13.2	13.5	13.7	14.0	67.4
Less Removals	1.0	1.0	1.0	1.0	1.1	5.1
Less Capital Contributions	0.6	0.6	0.6	0.6	0.6	2.9
Net Capital Expenditures	11.4	11.6	11.9	12.1	12.4	59.4

Table 3 below summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 and 2028-2032 rate periods. Amounts for the 2023-2027 plan and forecast include investment expenditures that were assigned to different ISDs in Hydro One's previous transmission application (EB-2021-0110), as further explained in TSP Section 2.12.

[2] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 3 - Hydro One – Rate Period Net Investment Expenditures

Description	Plan[3] 23-27	Act/Fcst[4] 23-27	Total 28-32
Transmission Lines Emergency Replacements	55.7	50.7	58.2
Below Materiality[5]	0.5	1.3	1.2
Total	56.2	52.0	59.4

The 2028-2032 capital expenditures in Table 2 are based on the five-year historical average gross expenditures as shown in Table 4. The average gross capital expenditures for 2020-2024 was $11.4M. The 2028-2032 forecasted expenditures are derived from this historical average, inflated by 2% each year.

Table 4 - Five-year Historical Average Capital Expenditures

Fiscal Year	Net ($M)	Gross ($M)
2020	12.0	13.1
2021	11.2	12.1
2022	12.2	13.3
2023	8.2	8.9
2024	8.0	9.4
2020-2024 Avg	10.3	11.4

Over the 2023-2027 rate period, Hydro One expects actual and forecast expenditures for Transmission Lines Emergency Replacements to be $5.0M lower than plan due to the number and type of assets needing emergency replacement over that period.

In the 2028-2032 period, Hydro One expects the expenditures for Transmission Lines Emergency Replacements to be $7.5M higher than the 2023-2027 actual and forecast amounts due to higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro

[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.
[5] "Plan" and "Act/Fcst" for Below Materiality investments show expenditures previously mapped to Other System Renewal Investments in the last transmission application EB-2021-0110.

One and other utilities have experienced during this period. Overall historic material cost escalation trends are described in SPF Section 1.8.3, including transmission and distribution poles, which have increased by 45% on average, since 2020, and conductors, cables and wires, which have increased by 65% on average since 2020.

6.0 ALTERNATIVES

This investment program is non-discretionary and, as such, no alternatives have been considered. Under the TSC, a transmitter is required to take action during an emergency to ensure public safety and to safeguard life, property and the environment as well as to protect the stability, reliability, and integrity of its transmission facilities. Failure to respond to an emergency or to prevent or minimize the effects of an emergency in a timely manner may jeopardize public and/or employee safety or negatively impact the provision of reliable service.

7.0 EXECUTION RISK AND MITIGATION

The work under this investment program is mostly unplanned in nature. However, there are risks to executing such unplanned work including the availability of resources and long lead times for the purchase of new transmission lines components. The risk of resources being unavailable is mitigated by having a process to enable the effective prioritization of resources to support immediate and emergent work as required. The risk of long procurement lead times is mitigated by having an adequate inventory of critical spare equipment.

APPENDIX C – HOSSM TRANSMISSION LINES EMERGENCY REPLACEMENT

As described in TSP 2.10, Hydro One has been operationally integrated with HOSSM since October 1, 2018. However, HOSSM remains financially and legally separate until a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One.

HOSSM continues to be the licensed owner and operator of its transmission system, however, it relies on Hydro One to carry out the day-to-day operations, pursuant to affiliate service agreements as outlined in Exhibit D-02-03. Although HOSSM is distinct and its approved revenue requirement is established separately, many processes including the asset management, planning and work execution approaches are common and integrated with Hydro One Transmission and are described within Hydro One's SPF and TSP.

Since HOSSM's programs are operationally integrated with Hydro One, the investment need, investment description, outcomes, and execution risks and mitigation described above for Hydro One in Sections 2.0, 3.0, 4.0 and 7.0, respectively, are applicable to HOSSM's transmission line emergency replacement program.

Table C-1 summarizes HOSSM's actual and forecast capital expenditures for the 2022-2026 rate period and the forecast capital expenditures for the 2027-2032 planning period.

Table C-1 - HOSSM – Investment Expenditures

($M)	Act/Fcst[6] 22-26	2027	2028	2029	2030	2031	2032	Total 27-32
Gross Capital Expenditures	5.3	1.9	0.8	0.8	0.8	0.9	0.9	6.2
Less Removals	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.5
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**5.0**	**1.8**	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**	**5.7**

Table C-1 above summarizes HOSSM's planned and forecast net capital expenditures for the 2022-2026 and 2027-2032 rate periods. The expenditures for 2027 are based on the

[6] "Act/Fcst" refers to actual (2022-2025) and forecast (2026) expenditures.

average gross three-year historical expenditure. In the 2027-2032 planning period, the expenditures for HOSSM's transmission line emergency replacement program are expected to be in line with the 2022-2026 forecast.

As noted above for Hydro One in Section 6.0, this investment is non-discretionary and, as such, no alternatives have been considered. Failure to respond to an emergency or to prevent or minimize the effects of an emergency in a timely manner may jeopardize public and/or employee safety or negatively impact the provision of reliable service.

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T-SR-16	**HIGH VOLTAGE UNDERGROUND CABLE SYSTEM REPLACEMENTS**
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	43.6	55.8	67.0	85.6	50.8	302.8

Summary:

This investment involves the replacement of high voltage underground cable system assets that are in poor condition and can no longer be relied upon to provide their intended function. The primary trigger of the investment is condition; however, safety, environment, and obsolescence are also important.

This investment summary document consists of four investments, organized into the following two categories:

- Cable system replacement projects:
  - X21 & X22 – Long Reach East JCT x Long Reach West JCT
  - H1L, H3L & H2JK – Gerrard TS x Basin TS & Don Fleet JCT x Basin TS
- Ancillary component replacement and refurbishment projects:
  - Terminations
  - Pumping plants

These investments are necessary to maintain service reliability associated with the unexpected failure of poor condition assets; eliminate the environmental hazard, obsolescence risk and maintenance associated with oil-filled cable systems; and reduce safety risks related to operating deficient terminations.

In previous filings, including Hydro One's last transmission application (EB-2021-0110), investments related to high voltage underground cable system replacements were presented in separate investment summary documents. To improve clarity and provide a comprehensive view of all high voltage cable investments, these have now been consolidated into a single investment. This ISD (T-SR-16), which previously covered only pumping plant refurbishment, has been repurposed to accommodate this change.

1.0 OVERVIEW

Underground transmission cable systems are used to transmit high voltage electricity below ground in areas where overhead lines are unsafe, not feasible, impractical or undesirable. They are typically installed beneath public roadways in densely populated urban centres connecting portions of the overhead network, generators and substations. Underground cable systems consist of high voltage power cables and ancillary components such as terminations and pumping plants used to support their operation.

Low-pressure liquid-filled (LPLF) cable replacements are primarily driven by deteriorated jacket and sheath condition, which present significant reliability risks and environmental hazards. The cable jacket is the outermost protective layer applied over the metallic sheath. Its primary functions are to provide mechanical, environmental and corrosion protection, and electrically isolate the sheath from ground. The sheath is a metallic layer applied over the insulation system, which consists of paper impregnated with dielectric insulating fluid (oil). It functions as a pressurization enclosure to contain the insulating fluid, prevent moisture and contaminant ingress, and provide a low-impedance path for charging and short-circuit currents. Damage to the jacket allows for water penetration, consequent sheath corrosion (accelerated by induced sheath voltages) and oil leaks. Water or contaminants that permeate the paper insulation generally result in permanent cable damage and failure that cannot be repaired, forcing cable replacement. In addition, jacket damage can allow significant circulating sheath currents to flow, thereby increasing cable temperature, leading to derating (reduction of power transmission capacity), and accelerated corrosion, which can result in oil leaks.

Select terminations are undergoing replacement due to deficiencies that compromise safety and reliability. Pumping plants are being refurbished due to poor condition and obsolescence, and the reliability risk they pose to the high-pressure liquid-filled (HPLF) cable system.

2.0 INVESTMENT NEED

X21 & X22 – Long Reach East JCT x Long Reach West JCT – Submarine Cable Replacement

Circuits X21 and X22 from Long Reach East JCT to Long Reach West JCT, totaling 3.96 circuit km or 1.98 route km, are 230 kV paper insulated low-pressure liquid-filled (LPLF) submarine transmission cables that provide the sole supply to Picton TS in Prince Edward County. For approximately 1.4 km these cables pass beneath Hayward Long Reach, a navigable commercial and recreational waterway connecting the Napanee River and Bay of Quinte to Lake Ontario. These cables are in poor condition as verified through condition assessments. Figures 1 and 2 shows Long Reach West JCT and the Hayward Long Reach, and an area map, respectively.

Figure 1: Long Reach West JCT & Hayward Long Reach

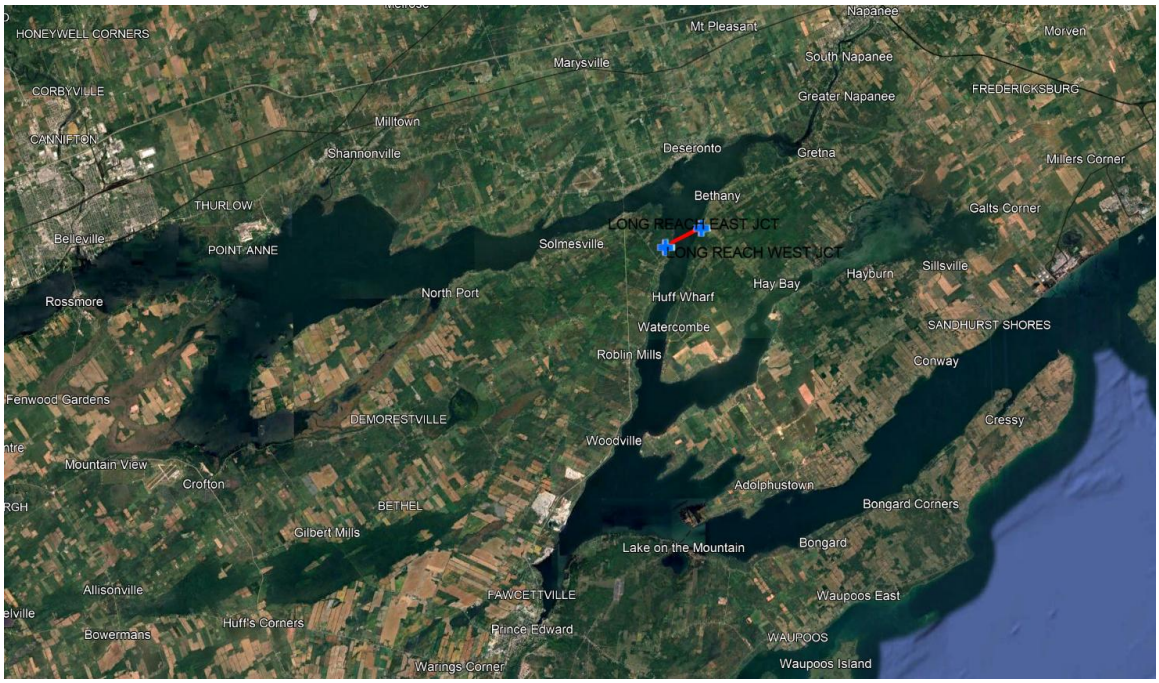

Figure 2: X21 & X22 – Long Reach East JCT x Long Reach West JCT – Route Map

The cable jackets have been tested and were found to be in deteriorated condition necessitating the need for replacement. The cables, terminations and oil pressure system have been the source of numerous oil leaks and are obsolete with limited spare part suppliers. Additionally, these cables are damaged by ice formation along the shoreline increasing the likelihood of jacket and sheath damage resulting in oil leaks.

Interruption or failure of X21 and X22 will negatively impact the power supply to Picton TS, with a capacity of 167 MVA, as well as the surrounding communities in Prince Edward County. This includes impacts to 12 distribution stations, solar generators totaling approximately 26 MW and multiple direct customers such as a retirement home, cement plant, arena, grocery store and water treatment plant. Furthermore, approximately 2.8 circuit km are routed on the lakebed where a significant oil leak would contaminate surface water requiring costly and challenging environmental remediation.

Based on their deteriorated condition and location under a major waterway, these underground cables require replacement. Not proceeding with this investment will result

in higher likelihood of cable failures causing unplanned prolonged circuit outages, loss of supply and oil leaks necessitating costly environmental remediation.

H1L, H3L & H2JK – Gerrard TS x Basin TS & Don Fleet JCT x Basin TS – Underground Cable Replacement

Circuits H1L and H3L from Basin TS to Gerrard TS, and H2JK from Basin TS to Don Fleet JCT, totaling 7.23 circuit km or 4.33 route km, are 115 kV paper insulated low-pressure liquid-filled (LPLF) transmission cables installed in the 1950s and 1960s. They provide a network feed connecting Gerrard TS, Leaside TS, Esplanade TS, Basin TS, Hearn SS and the Portlands Energy Centre. These circuits parallel the Don River in downtown Toronto and the Portlands, and are near Lake Ontario, public parks and major roadways. These cables are in poor condition as verified through condition assessments. Figure 3 shows a map of the cable routes and their proximity to the Don River.

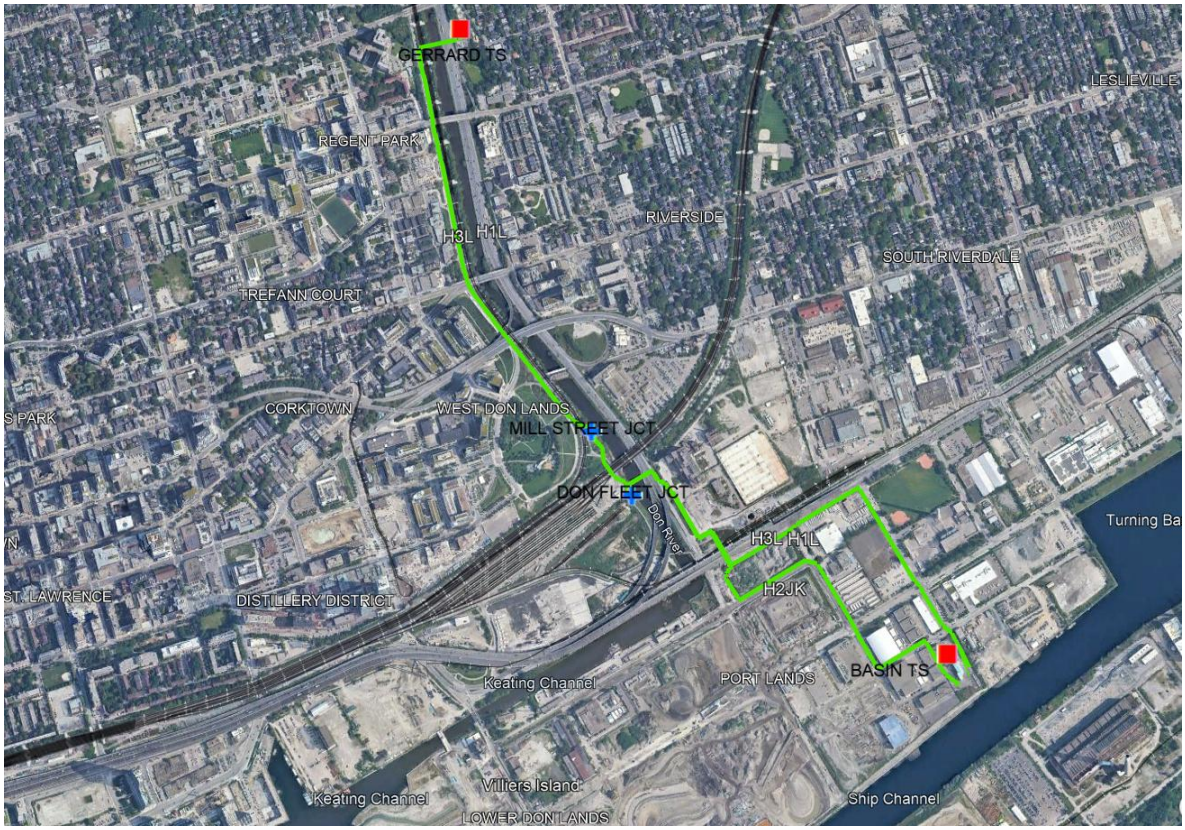

Figure 3: H1L, H3L & H2JK – Gerrard TS x Basin TS & Don Fleet JCT x Basin TS Cable Routes

For design, planning and construction efficiency, and to minimize public impact, this investment will address the following line-sections:

- H1L/H3L – Basin TS x Mill Street JCT – 1.53 route km (3.06 circuit km)
- H1L/H3L – Mill Street JCT x Gerrard TS – 1.37 route km (2.74 circuit km)
- H2JK – Basin TS x Don Fleet JCT – 1.43 route km (1.43 circuit km)

Similar to the X21 and X22 investment, these cables are being replaced due to poor jacket condition; cable, termination and oil pressure system leaks; and obsolescence risks due to limited spare part suppliers.

Interruption or failure of H1L, H3L and H2JK will negatively impact the power supply to the Toronto Hydro-Electric System Limited and their downstream customers, especially downtown and in neighbourhoods east of the Don River such as Riverdale, Leslieville, the Beaches and the Portlands. These circuits also facilitate connections to the Portlands Energy Centre, a 550 MW generating station supplying Toronto. Furthermore, the majority of these cables are routed parallel to and cross the Don River which connects to Lake Ontario, where a significant oil leak would contaminate surface water requiring costly and challenging environmental remediation.

Based on their deteriorated condition and location near a major waterway, these underground cables require replacement. Not proceeding with this investment will result in higher likelihood of cable failures causing unplanned prolonged circuit outages, loss of supply and oil leaks necessitating costly environmental remediation. Locating, repairing and environmental remediation of an oil leak caused by jacket deterioration and sheath corrosion typically entails a 40-day outage, as further discussed in TSP Section 2.2.4.2. However, if water or contaminants permeate the paper insulation, cable replacement is required and will take many months.

Termination Replacement

Terminations, also called potheads, are insulated electrical terminals used to transition between underground cables and overhead conductors or station equipment such as buses. Terminations installed in the 2000s as part of 115 kV and 230 kV XLPE cable systems are experiencing a higher-than-normal failure rate. To date, three terminations have failed, two while in-service and one during offline hi-pot testing. These failures are usually explosive, causing an upward expulsion of the insulator. In past explosive failures, fragments have traveled more than 60 metres. Figures 4 through 7 show the L51D white phase north end failure in 2017 at Lambton TS #2.

Figure 4:
L51D White Phase (North End)
Termination Failure

Figure 5:
L51D White Phase (North End)
Termination Failure
Base and Structure

Figure 6:
L51D White Phase (North End)
Termination Failure
Cable Leakage Path (After Cleaning)

Figure 7:
L51D White Phase (North End)
Termination Failure
Stress Cone

Failure investigations have revealed that the design and installation allowed for substantial relative movement between the cable and stress cone, an internal termination component used to grade the electrical stress. This movement allows for internal partial discharge (electrical arcing) to develop, which can lead to failure. Furthermore, there is insufficient pressure relief and/or the termination housing (insulator) is not adequately secured to the structure to prevent upwards expulsion.

These terminations are a significant public and employee safety hazard. Most are in urban centres near public areas such as residential buildings, parks, schools, and public transit, increasing the potential for a failure to cause substantial injury. Additionally, many of these terminations facilitate the electrical supply to heavily populated areas such as Toronto. An unplanned extended outage poses a considerable reliability risk through loss of redundancy or customer supply. Unplanned termination replacement and commissioning takes approximately one week and requires an outage.

Pumping Plant Refurbishment

Pumping plants, also known as pressurization plants, are used to maintain constant stable oil pressure and are vital for reliable high-pressure liquid-filled (HPLF) cable operation. In an oil-filled cable system, pressure fluctuates based on load and environmental conditions (i.e. temperature). Pumping plants consist of the following principal components: reservoir tanks; valves; manifolds; piping; electrical pumps; control, monitoring, alarm, communication, cathodic protection, backup pressurization and HVAC systems; and associated civil infrastructure.

Approximately 61% of Hydro One's underground transmission system consists of 115 kV and 230 kV HPLF cables that operate dependably, provided that the dielectric fluid is continually pressurized. Most pumping plants were installed in the 1970s and 1980s with control systems upgraded or replaced in the 1990s. Due to their age, many components are obsolete with limited spare parts suppliers. Through condition assessment and functional testing, these assets have been verified as needing to be replaced.

Non-functioning pumping plants can result in a significant loss of pressure that will cause the cables to be immediately taken out-of-service, impacting customers through loss of supply or redundancy. Loss of pressure can allow water or contaminants to permeate the paper insulation, generally resulting in permanent cable damage and failure that cannot be repaired, forcing cable replacement. Cable replacement is costly and time-consuming and would further impact service to customers.

Failed control, monitoring, alarm and communication systems will result in an inability to control pump operations; maintain oil pressure; and monitor and log pressures,

temperatures, alarm details, oil and gas levels, and pump operations. These systems are essential to reliably operate the HPLF cable system and diagnose pumping plant breakdowns. Furthermore, pumping plants normally operate unmanned, thus these system failures would require oil pressures and levels to be monitored and controlled manually by on-site personnel on a continuous basis. Oil-filled cables must remain under positive pressure to operate and prevent premature degradation.

The majority of Hydro One's cables are installed in densely populated urban centres, such as the Greater Toronto Area (GTA), Ottawa and Hamilton, and serve through Local Distribution Companies (LDC), a significant portion of load in those regions. Consequently, failures resulting in loss of supply or redundancy will negatively impact downstream LDC customers. Pumping plants are integral to reliably operating HPLF cables and supplying connected customers.

For the 2023-2027 rate period, pumping plant refurbishment was initially planned to begin in 2025. However, Hydro One was required to reprioritize capital expenditures due to increasing demand for non-discretionary and externally-driven investments, coupled with significant cost escalation, as described in TSP 2.9. As a result, pumping plant refurbishment was deferred to the 2028-2032 period

3.0 INVESTMENT DESCRIPTION

Cable Replacements

The scope of cable replacement investments includes the following:

- Replace existing deteriorated oil-filled cables and ancillary components with oil-free cross-linked polyethylene (XLPE) cables or overhead lines.
- Replace existing terminations, arresters and associated equipment with non-fragmenting components.
- Install on-line distributed temperature sensing (DTS) systems where needed and feasible.
- Adjust line protections due to the change in cable type.
- Decommission the existing oil-filled cables and associated ancillary components.

When installing new underground cables, various installation methods will be considered, such as open-cut and tunnel. Open-cut, also called open-trench or trenching, is the traditional method of underground cable installation and is roughly one to two metres in depth. It involves excavating a trench along the route, constructing concrete duct banks, pulling cables, backfilling and reinstating the surface. Tunnel installations are generally at a depth of 20+ metres, three metres in diameter, and involve the construction of access shafts and the use of a boring machine. Open-cut installations are typically less costly but may result in substantial surface disruptions and require the relocation of conflicting utilities including water, telecommunications, and gas. Tunnel installations are more costly and challenging to maintain but result in less surface disruption during construction. High voltage submarine cables are installed using a cable-laying vessel, either directly on the seabed or buried within a trench. In locations where the cables may be exposed to potential damage, such as areas with frequent anchoring or near shore where they make landfall, additional mechanical protection is applied.

Termination Replacement

The scope of this investment is to replace 103 deficient, poorly designed and poor condition terminations on 20 high voltage underground cable circuits with non-fragmenting terminations.

Pumping Plant Refurbishment

This investment will refurbish or replace approximately 26 pumping plants on the HPLF cable system. Refurbishments involve individual component replacements and focus on control, monitoring, alarm, communication, cathodic protection, backup and HVAC systems. Replacement will be done when major components such as piping, valves, civil infrastructure (buildings) and tanks are in poor condition, and it is no longer practical to maintain them.

4.0 OUTCOMES

4.1 OEB RRF OUTCOMES

As a result of these investments, Hydro One will:

- Maintain customer and system reliability by reducing the likelihood of unplanned outages associated with the unexpected failure of poor condition assets.
- Improve customer and system reliability by eliminating planned and unplanned outages related to oil-filled cable system maintenance, leaks and failures due to their deteriorated condition.
- Eliminate the environmental hazard and obsolescence risks associated with operating oil-filled cable systems by using oil-free XLPE cables.
- Eliminate the preventative maintenance, repair and environmental remediation associated with oil-filled cables.
- Reduce public and employee safety risks associated with operating deficient, poorly designed and poor condition terminations that have a higher probability of explosive failure.

Table 1 presents anticipated benefits as a result of these investments in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Maintain system and customer reliability by replacing poor condition high voltage cables and ancillary components.
Operational Effectiveness	• Maintain operational effectiveness and flexibility to customers connected to the underground cable system by replacing poor condition and obsolete equipment.
Public Policy Responsiveness	• Eliminate the risk of environmental contamination due to possible oil leaks by using oil-free XLPE cables in new installations. • Reduce the safety risk by replacing deficient, poorly designed and poor condition terminations.

5.0 EXPENDITURE PLAN

Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 planning period. Detailed costs for each investment can be found in Appendix B.

Table 2 - Hydro One – Investment Expenditures[1,2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	43.6	55.8	67.1	86.8	50.9	304.2
Less Removals	0.0	0.0	0.0	1.1	0.1	1.4
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**43.6**	**55.8**	**67.0**	**85.6**	**50.8**	**302.8**

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred investment.

ALTERNATIVE 1: REACTIVE REPLACEMENT

Reactive replacement of underground cables and ancillary components means Hydro One would continue to operate and maintain the existing assets and replace them upon failure. Cable replacement investments are multiyear projects that are complex to design, plan and execute, therefore it is not practical to replace cables or major ancillary components reactively. This alternative was considered and has been rejected since failure of these assets will result in public and employee safety risks associated with defective terminations, prolonged circuit outages, potential customer interruptions, loss of redundant supply negatively affecting operational flexibility, and potential oil leaks requiring environmental remediation.

ALTERNATIVE 2: PLANNED REPLACEMENT (RECOMMENDED)

Planned replacement is the recommended alternative. It involves planned replacement of high voltage cable and ancillary components that are in poor condition and can no longer be relied upon to provide their intended function. Due to their deteriorated condition and the increased risk of cable failure and oil leaks, planned replacement will mitigate risks to

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] Forecast net capital expenditures for the 2028-2032 period include $4.5M of immaterial investments.

customers and the environment. The replacement of deteriorated cables and ancillary components will address safety risks associated with deficient terminations, reliability concerns related to operating poor condition assets, and eliminate the obsolescence risks linked to operating assets with limited manufacturer support.

7.0 EXECUTION RISK AND MITIGATION

As described in TSP Section 2.11, Capital Work Execution, Hydro One follows a Transmission Capital Project Delivery Model, under which project risks are identified and mitigation plans implemented. There is potential for normal execution risks that may affect the timely completion of these investments, such as:

- **Outage Constraints:** Planned outages are required to complete this replacement work and may include multiple circuits. This risk will be mitigated by scheduling and coordinating with customers and other planned outages well in advance.
- **Construction Coordination:** Underground cables are typically installed in densely populated urban areas under roadways where there are often other nearby infrastructure projects (e.g. road resurfacing, sewer installation, building construction, etc.). To execute cable replacement efficiently and obtain construction permits, coordination with local governments, such as The City of Toronto, and other utilities must be done well prior to any construction activities.
- **Procurement Challenges:** High voltage cables and ancillary components such as terminations, have long procurement timelines and are considered long lead time materials. Considering manufacturer availability and risk of production delays, it is critical to order these components well in advance of their installation.
- **Pumping Plant HPLF Cable Pressure:** Specifically, for the pumping plant refurbishment investment, care must be taken to ensure that the connected HPLF cables remain under pressure during construction. These risks will be mitigated through detailed planning and preparation with the execution team and contractors.

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

The investments proposed in this ISD are complex and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.11. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project, the in-service year and the project total estimates for the 2023-2027 and 2028-2032 rate periods. Project maturity is defined by the following project phases:

- Execution (E), which reflects fully approved project work;
- Planning and Definition (P), which reflects non-execution work, regardless of level of upfront development; and
- Complete (C), which reflects that the project has been placed in service

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in the table below in reference to project total variances and overall project schedule variances.

Table B1 - Hydro One – Detailed Material Investment Costs ($M)

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[3]			
		Act/Fcst[4,5] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
	Projects														
T-SR-16.1	X21 & X22	1.2	29.7	43.3	60.7	67.7	0.0	201.4	P	202.5	2031	-	-	-	-
T-SR-16.2	H1L, H3L & H2JK	0.0	0.0	0.4	0.9	5.6	37.9	44.9	P	204.3	2035	-	-	-	-
T-SR-16.3	Terminations	0.6	12.9	11.0	0.0	0.0	0.0	23.9	P	24.6	2029	-	-	-	-
T-SR-16.4	Pumping Plants	0.0	0.4	0.5	4.6	11.2	11.4	28.2	P	28.2	2032	T-SR-16	P	11.5	2028
		The Pumping Plants Refurbishment project is expected to be placed in service in 2032 at a project total of $28.2M, which is $16.7M higher than the prior project total primarily due to an expanded scope of work. This investment originally targeted approximately nine pumping plants but was expanded to include 17 additional pumping plants on the entire HPLF cable system due to condition. The in-service date was delayed from 2028 to 2032 due to capital reprioritization.													

[3] "Prior Project Forecast" refers to the forecast project total and in-service date when Hydro One revised the capital 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.
[5] Actual and forecast net capital expenditures for the 2023-2027 period include an additional $2.8M of immaterial investments.

T-SR-17	**OPGW INFRASTRUCTURE PROJECTS**
Primary Trigger:	Performance
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	20.7	44.0	50.9	43.0	24.6	**183.2**

Summary:

This investment focuses on enhancing Hydro One's fibre-optic telecommunications network by installing Optical Ground Wire (OPGW) on targeted 230 kV and 115 kV transmission lines across the province. These installations will eliminate existing coverage gaps, improve geographic diversity, and strengthen network reliability by replacing aging leased third-party fibre and leased metallic telecom facilities with Hydro One-owned infrastructure.

During the 2023-2027 rate period, the portfolio consisted of 24 individual capital investments. Ten of these projects have completed or are expected to be completed prior to 2028, while four were streamlined through coordination with other investments. The majority of the investments in the 2028-2032 planning period have carried over from the 2023-2027 rate period due to the reprioritization of capital expenditures, as described in TSP Section 2.9, as well as outage availability constraints.

Collectively, these initiatives support a more resilient, fully integrated OPGW fibre network essential for Hydro One's system protection, control, and telecom applications.

1.0 OVERVIEW

Hydro One utilizes fibre-optic cable infrastructure including Hydro One-owned and operated Optical Ground Wire (OPGW) aerial fibre-optic cables. In addition, Hydro One uses fibre strands acquired through indefeasible right of use (IRU) agreements from third-party telecom providers, which is referred to below as third-party fibre. An IRU is an exclusive and irrevocable right of use granted by the owner of a communications system to a customer or user of that system. Instances of past failures of third-party fibre have compromised Hydro One's ability to reliably operate the transmission system.

To maintain transmission system reliability, Hydro One’s asset management strategy focuses on two key actions:

- Gradually replacing less reliable third-party fibre with Hydro One-owned OPGW where practical; and
- Expanding the OPGW footprint to reach facilities currently served by leased metallic telecom services.

Under this investment, Hydro One will also replace some leased metallic copper-based circuits from telecommunication service providers (Telco) that provide communication-aided protection schemes at transmission stations. The metallic copper-based leased circuits perform worse than third-party fibre circuits, which in turn perform worse than Hydro One owned OPGW fibre infrastructure. Further, third-party carriers no longer offer Service Level Agreements (SLAs) on legacy services with Hydro One.

Hydro One has been proactively installing OPGW through the shield wire replacement program described in TSP Section 2.12, T-SR-07 and line refurbishment projects described in TSP Section 2.12, T-SR-13 when feasible. However, because these projects are primarily driven by the need to replace deteriorated shield wire, they do not always provide complete end-to-end fibre paths. The programs funded under this investment are designed to close those gaps by adding the missing fibre segments needed to create continuous, fibre-based telecom routes. Thus, this investment complements, but does not overlap with, the investments in TSP Section 2.12, T-SR-07 and T-SR-13. In addition, while TSP Section 2.12, T-SR-12 also includes OPGW installations, those investments

are specifically intended to replace obsolete microwave radio equipment and are mutually exclusive from this investment.

2.0 INVESTMENT NEED

This investment focuses on enhancing Hydro One's fibre-optic telecommunications network by installing OPGW on targeted 230 kV and 115 kV transmission lines across the province. These installations will eliminate existing coverage gaps, improve geographic diversity, and address the reliability risks posed by failing, leased third-party fibre as well as leased circuits provided by Telco. Hydro One is obligated to build and maintain a reliable and redundant communication/protection system to ensure compliance with applicable North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) regulatory compliance requirements.

The Hydro One power system telecommunications network is currently based on Synchronous Optical Network (SONET) technology. This network is primarily utilized by protection systems and Supervisory Control and Data Acquisition (SCADA) telemetry systems. The network is also used for secondary purposes, such as communicating non-operational data, business data, voice communications, and security information. Finally, the network provides backhaul communication for the provincial mobile radio system and connectivity between different control centres.

A large portion of the fibre infrastructure at Hydro One (approximately 40%, or 1,700 km) consists of leased third-party fibre. The market for third-party fibre has shifted from what it was 25 years ago. Fibre is no longer being offered by many third-party providers and as such the maintenance of existing fibre plant is given lower priority. Reduced availability and lower reliability of new third-party fibre, and increasing challenges to the renewal of contracts for existing leased fibre paths being utilized by Hydro One pose significant future operational risk to the Power System Telecom Services (PSTS) network.

Historically, third-party fibre routes have performed worse than Hydro One owned OPGW sections in terms of reliability as they tend to be installed in public road allowances, on wood poles or along railroad tracks which makes them prone to frequent and prolonged outages, as further described in TSP Section 2.2.2.5.

Hydro One's power system telecommunications network uses a ring architecture to provide robust and reliable communication between transmission stations. This is made possible by reliable, geographically diverse, redundant, fibre-optic cable infrastructure and network configuration. Hydro One utilizes approximately 4,300 kilometers of fibre-optic cable infrastructure including Hydro One-owned and operated aerial fibre-optic cables as well as fibre strands acquired through IRUs. Aerial fibre-optic cable includes OPGW technology with strands of fibre embedded inside of the shieldwire mounted on top of high-voltage transmission structures.

Hydro One also utilizes a large number of leased metallic copper-based circuits from Telcos for communication-aided protection schemes at many transmission stations. In general, due to the utilization of older technologies combined with aging infrastructure, the metallic copper-based leased circuits perform worse than third-party fibre circuits. Due to the current age and obsolescence of these communication circuits, they have become failure-prone and hence not desirable for transmission protection, control and monitoring applications. With carrier support for these legacy services now limited through the discontinuance of SLA offerings, this reduced reliability is reflected in outages experienced by Hydro One, as summarized in Table 1.

Table 1 illustrates outages affecting approximately 430 leased copper-based circuits and shows that the number of outages and total outage time has increased over the last five years.

Table 1 - Outage Statistics of PSTS Leased Legacy Circuit Type (Circuits Carrying Power System Telecom Services)

Item	2021	2022	2023	2024	2025
Number of tickets logged by ITMC[1]	78	29	96	128	200
Total outage time (hours)	9,214	3,777	19,020	24,617	23,185
Average outage time per instance (hours)	118	130	198	192	116

[1] ITMC: Integrated Telecom Management Centre.

In addition, effective March 2026, the main provider of dedicated leased circuits to Hydro One is no longer accepting new orders for leased circuits over their metallic infrastructure citing lack of qualified resources and equipment. The provider has submitted a notice of de-standardization to the Canadian Radio-Television and Telecommunications Commission (CRTC) and only provides maintenance of these circuits on a best effort basis. The provider has accelerated their plans to only offer leased circuits over fibre infrastructure, requiring the customer (Hydro One) to carry the additional financial burden of paying for installation of fibre infrastructure from the relevant Hydro One site to the carrier's central office.

The above factors have compelled Hydro One to invest in replacement of Telco-based leased facilities with Hydro One-owned OPGW fibre infrastructure, thus increasing the overall reliability of the PSTS network. The proposed investments will reduce reliance on third-party acquired fibre, which will address the reduced performance and reliability of third-party fibre (compared to Hydro One-owned OPGW), and the risk it poses for critical PSTS that support the operation of the Bulk Power System. These projects will improve the reliability of Hydro One-owned OPGW fibre facilities. These installations will also eliminate existing coverage gaps.

3.0 INVESTMENT DESCRIPTION

The projects and program described below aim to maintain or restore the reliability of Hydro One's existing power system telecom network by replacing third-party fibre, legacy Telco leased circuits and metallic cable facilities with OPGW fibre. In addition to these individual material projects, this investment includes multiple discrete investments that fall below Hydro One's Transmission materiality threshold. The immaterial investments address the same categories of assets and are intended to achieve the same outcomes as the material investments listed below. Across the entire scope of this investment, Hydro One expects to install approximately 580 km of OPGW fibre during the 2028-2032 planning period.

During the 2023-2027 rate period, the portfolio consisted of 24 individual capital investments. As described in TSP Section 2.9, Hydro One was required to reprioritize capital expenditures due to increasing demand for non-discretionary and externally-driven

investments, coupled with significant cost escalation. Ten of the 24 projects planned for the 2023-2027 period have completed or are expected to be completed prior to 2028, while four were streamlined through coordination with other investments, such as the shieldwire replacement program described in TSP Section 2.12, T-SR-07. The majority of the investments planned for the 2028-2032 planning period under this Investment Summary Document (ISD) have been deferred from the 2023-2027 rate period due to the reprioritization of capital expenditures, as well as outage availability constraints.

Martindale TS by Algoma TS OPGW Link

The Martindale TS to Algoma TS OPGW link project aims to provide complete end-to-end fibre infrastructure between these two stations. Certain sections of the path between these two stations already have OPGW installed. The existing power system telecom link from Martindale by Algoma is on third-party fibre installed on wood poles in the area. Historically, this link has experienced one of the highest rates of failures on Hydro One's power system telecom network. This project will build the remaining sections of OPGW (approximately 95 km) on line S2B in this area to fill in the gaps and complete an end-to-end fibre path in order to restore communication reliability on SONET Ring 7.

Ansonville TS x Hunta SS A4H Completion of OPGW

The Ansonville TS to Hunta SS OPGW link investment covers the installation of the remaining 41 km of OPGW to provide full end-to-end connectivity. This investment will allow the legacy Telco metallic circuits that provide communications for protection and SCADA systems to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. Combined with the existing OPGW fibre, this project will provide a fibre-based backup path, allowing the removal of the obsolete Power Line Carrier (PLC) based backup protections on the 500 kV line D501P/D502P.

London Area West Telecom OPGW Infrastructure

A number of legacy Telco leased metallic circuits and old dedicated metallic cable infrastructure serve as telecom media for DC remote trip protections in the London area. This infrastructure is outdated and in need of a complete overhaul. This investment will use the existing and new OPGW-based fibre on a number of lines (approximately 50 km)

emanating from Buchanan TS to establish a geographically diverse fibre-optic network for protection and SCADA applications.

Pembrooke TS x Barrett Chute SS OPGW

This investment will allow the legacy Telco metallic circuits and obsolete PLC equipment providing communications for protection and SCADA systems in the area along the Ottawa River to be replaced with modern, OPGW fibre-based, Hydro One-owned telecom facilities. This investment builds on new fibre installed on transmission lines from Pembrooke TS to Barrett Chute TS (approximately 110 km), providing much needed reliable communication for protection and SCADA applications in an underserved area of the province. The new OPGW links, combined with existing and new OPGW installation planned for the 2028-2032 planning period will provide a geographically-diverse, redundant protection and SCADA system which replaces unreliable leased Telco circuits and analog PLC systems.

S2S OPGW Installation (Stayner TS x Owen Sound TS)

This investment will allow the third-party leased fibre-optic facilities that provide communications for protection and SCADA systems in the Stayner TS to Owen Sound TS area (approximately 70 km), to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. These third-party facilities experienced several unexpected failures from 2015 to 2024 resulting in loss of redundant protection circuits. The expected benefits are improved communications reliability for protection and SCADA applications. An added benefit would be the reduction in the frequency of Protection and Control staff dispatches due to failure of third-party fibre facilities.

Hamilton/Niagara Area new OPGW Investments

This investment will enable the connection of a number of 230 kV and 115 kV transformer stations in the Niagara area in a ring, providing the necessary backup protections in the event of fibre failure. Installation of new OPGW will connect Stanley TS and Murray TS to Beck TS # 1 (via Beck TS #2) and will complete the connection from Murray TS to Allanburg TS (approximately 50 km). This investment will replace several failing legacy Telco metallic circuits as well as dedicated metallic cables that provide communications for protection and SCADA systems with modern, fibre-based, Hydro One-owned telecom

facilities. The expected benefits are improvement of communications reliability for protection and SCADA applications, and avoiding the need for upgrades to Telco entrances at these stations.

New Aerial/Underground Fibre Infrastructure Install

This investment will enable installation of lengths of OPGW (> 5 km) to be installed on transmission lines in conjunction with sustainment driven projects or programs. In many instances, a lines sustainment driven project or program (e.g., shieldwire replacement program described in TSP Section 2.12, T-SR-07) installs new OPGW on a 115 kV or 230 kV transmission line, but in disjoint sections. The sustainment program addresses only sections that show various signs of degradation, hence the disjoint installation. For OPGW to be useful for PSTS applications, it needs to provide a full end-to-end (station to station) connectivity. This investment is intended to fill the gaps left by sustainment projects and programs by installing OPGW on pre-selected lines each year. The investment aims to provide full end-to-end OPGW connectivity, taking advantage of sustainment programs' line outages, schedules and lines crew mobilization.

4.0 OUTCOMES

4.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 2 - Outcomes Summary

Customer Focus	• Maintain system reliability and reduce risk of outages that affect customers
Operational Effectiveness	• Maintain reliability of the transmission system through ensuring a reliable communication network by replacing poor-performing and deteriorated third-party fibre cables with Hydro One-owned OPGW cable to the extent possible.
Public Policy Responsiveness	• Hydro One is obligated to build and maintain a reliable and redundant communication/protection system to ensure compliance with applicable NERC and NPCC performance standards.

5.0 EXPENDITURE PLAN

Table 3 below summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 3 - Hydro One - Investment Expenditures[2,3]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	21.3	45.3	52.7	44.2	25.2	188.8
Less Removals	0.6	1.4	1.8	1.2	0.6	5.6
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**20.7**	**44.0**	**50.9**	**43.0**	**24.6**	**183.2**

As shown in Appendix B, Hydro One expects the forecast project totals for the projects in this investment to increase for the 2028-2032 planning period relative to the prior forecasts for the 2023-2027 period due to scope increases for certain projects as well as higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period.

Table 4 below summarizes Hydro One's planned and actual/forecast net capital expenditures for programs under this investment for the 2023-2027 and 2028-2032 rate periods.

[2] Forecast net capital expenditures for the 2028-2032 period include $28.5M of immaterial projects and $17.5M of immaterial programs.
[3] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 4 - Hydro One – Program Expenditure Continuity Over Rate Periods

Description	Plan[4] 23-27	Act/Fcst[5] 23-27	Total 28-32
New Aerial/Underground Fibre Infrastructure Install	18.1	4.5	41.0
Below Materiality	5.8	4.0	17.5

For the 2023-2027 period, Hydro One expects actual and forecast expenditures for this investment to be $15.4M lower than plan due to the reprioritization of capital expenditures. Over the 2028-2032 planning period, program expenditures are higher than those in the 2023-2027 period due to additional, newly identified sections required to complete reliable end-to-end OPGW connectivity as Hydro One's fibre footprint continues to expand, as well as the effect of inflationary pressures over the 2023-2027 period.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

This alternative is not recommended as the reliability degradation of the Hydro One power system telecom network will directly impact the operation of the transmission system. Hydro One cannot continue to rely on third-party fibre and legacy telco facilities for its long-term power system telecom needs, due to the high failure rates associated with these facilities. Such failures result in loss of redundancy and loss of communication of protection systems, adversely impacting the reliability of the transmission system and delivery of service to customers.

ALTERNATIVE 2: FIBRE-OPTIC OPGW INFRASTRUCTURE DEVELOPMENT INVESTMENTS (RECOMMENDED)

This alternative is preferred as it will maintain or restore robust and reliable communications throughout Hydro One's power system telecom network.

[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.

Additional OPGW investments in areas throughout the province that are included in this investment will allow Hydro One to complete certain end-to-end fibre-optic paths by addressing gaps in the OPGW fibre that is being installed as part of Hydro One shieldwire replacement or line upgrade programs. This investment will also enable Hydro One to remove certain unreliable third-party fibre and leased Telco metallic circuits throughout the province and replace them with Hydro One-owned facilities, thus avoiding the costs of leasing or renewing the use of these third-party facilities.

7.0 EXECUTION RISK AND MITIGATION

Execution risks include potential delays in required circuit outages to carry out replacement work. Hydro One will manage and stage the investments under this ISD to ensure that outages are available when required and disruptions to customers are minimized. The availability of resources and other competing investments are also a risk to investment completion. Hydro One will develop a detailed project and resource plan to ensure resources are available when needed.

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

The investments proposed in this ISD are complex and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.11. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project, the in-service year and the project total estimates for the 2023-2027 and 2028-2032 planning periods. Project maturity is defined by the following project phases:

- Execution (E), which reflects fully approved project work;
- Planning and Definition (P), which reflects non-execution work, regardless of level of upfront development; and
- Complete (C), which reflects that the project has been placed in service

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in the table below in reference to project total variances and overall project schedule variances.

1

Table B1 - Hydro One – Detailed Material Investment Costs ($M)[6]

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[7]			
		Act/Fcst[8] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
	Projects														
T-SR-17.1	Martindale TS by Algoma TS OPGW link	0.0	0.0	0.0	1.8	7.2	10.2	19.2	P	19.2	2032	17.2	P	11.1	2030
		The project was in a preliminary planning phase when the original forecast for the 2023-2027 period was established. Subsequently, an additional 65 km of OPGW was added to the scope, including new telecom and teleprotection equipment to support a full end-to-end solution. The project has been deferred due to portfolio reprioritization.													
T-SR-17.2	Ansonville x Hunta A4H Completion of OPGW	0.0	0.8	3.9	4.7	3.7	0.0	13.0	P	13.0	2031	17.4	P	5.1	2029
		The project was in a preliminary planning phase when the original forecast for the 2023-2027 period was established. Subsequently, additional scope was added to include the installation of station terminations for existing OPGW. The project schedule has been shifted to coincide with a line sustainment A4H upgrade project. Cost escalations have also contributed to the variance.													
T-SR-17.3	London Area West Telecom OPGW Infrastructure Installation	0.0	0.8	2.7	6.3	3.7	-0.1	13.4	P	13.4	2031	17.7	P	11.5	2031
T-SR-17.4	Pembrooke TS x Barrett Chute SS OPGW	0.0	2.5	9.2	8.2	4.7	0.0	24.5	P	24.5	2031	17.5	P	13.0	2029
		The project was in a preliminary planning phase when the original forecast for the 2023-2027 period was established. Subsequently, additional scope was added to include the installation of telecom and teleprotection equipment and channels to realize immediate benefits. The project has been deferred due to portfolio reprioritization. Cost escalations have also contributed to the variance.													
T-SR-17.5	S2S OPGW Installation (Stayner x Owen Sound)	0.0	0.6	3.7	4.7	5.3	-0.2	14.2	P	14.2	2032	17.9	P	11.5	2031

[6] Figures presented in the tables may not sum to the totals shown due to rounding.
[7] "Prior Project Forecast" refers to the forecast project total and in-service date when Hydro One revised the capital and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[8] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

T-SR-17.6	Hamilton/Niagara Area new OPGW Investments	0.0	0.5	5.0	4.1	2.3	0.0	11.9	P	11.9	2031	17.2	P	4.9	2026
		The project was in a preliminary planning phase when the original forecast for the 2023-2027 period was established. Subsequently, an additional 29 km of OPGW was added to the scope including station entrances and telecom equipment to create a more robust and comprehensive network. The project has been deferred due to portfolio reprioritization. Cost escalations have also contributed to the variance.													

T-SR-19	**CONTROL EQUIPMENT REPLACEMENTS**
Primary Trigger:	Obsolescence
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	11.6	11.9	12.1	12.3	12.6	60.5

Summary:

This investment involves the replacement of obsolete automation equipment and primarily targets the Remote Terminal Units (RTU) for replacement. The RTU is a critical component of the Hydro One Supervisory Control and Data Acquisition (SCADA) system, providing control and monitoring of transmission stations to Hydro One's control centers. RTU failures are considered high risk as they can result in a complete loss of remote station monitoring and control. The main trigger of the investment is the device expected service life (ESL). The investment is expected to minimize Hydro One's operational risks and maintain effective and reliable control and monitoring of the power grid.

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1.0 OVERVIEW

The Control Equipment Replacements investment targets the replacement of automation devices that are obsolete and beyond ESL. Hydro One will focus on the legacy and first-generation modern devices that have been identified as problematic based on failure rates or deficiency reports. The extent of the work required at each station depends on the type of RTU replacement.

2.0 INVESTMENT NEED

The RTU is an automation device that interfaces with primary yard equipment providing control and monitoring functions for the transmission station to the control center. The RTU accepts physical wired inputs and outputs (physical I/O) from the primary equipment and performs a digital conversion for remote usage by the control centers. Failures of RTU are very high-risk events, as they can lead to total loss of station SCADA functionality.

Hydro One currently has a total of 1,137 RTUs installed across the province. As described in TSP Section 2.2.2.4 and shown in Table 1, the RTU device can be categorized into three vintages.

Table 1 - RTU Type Description

Type	Description	Production Status	Vendor Support
Legacy	Copper-based technology with a high volume of physical wiring, pre-LAN based communication.	Obsolete	No
First-Generation Modern	Early IP-based devices; no longer manufactured (discontinued).	Obsolete	No
Modern (current)	Current Hydro One standard devices built on contemporary IP-based communication technology	Active	Yes

Legacy RTUs are obsolete copper-based technology, typically with a high volume of physical I/O and slow point-to-point communication as they lack LAN capable ports. These devices have been long discontinued by the manufacturer, with no ability to obtain spare units or parts. In addition to hardware scarcity, the software used to configure these units is also outdated. These issues can lead to an outage of significant duration if legacy units fail in the field. If a like-for-like replacement is not possible (which is increasingly the case

as older parts are unavailable), a complete redesign and commissioning of a new RTU is required.

Modern RTUs are IP based devices that connect to the station Local Area Network (LAN) infrastructure to communicate to the control center. The first-generation of these modern RTUs are now discontinued, no longer in production, and are no longer supported by the vendor. Hydro One's ability to support these devices is dependent on the on-hand spares supply.

Hydro One stations are designed such that they can be configured with different operating scenarios. In cases where a circuit breaker may "see" voltage from multiple sources, a Programmable Synchrocheck Relay (PSR) device is used to select the correct voltage source and check for synchronization on both sides of a circuit breaker before the RTU operates the circuit breaker. PSRs, if present, are always coupled with an RTU installation. Failure of a PSR will introduce risk to circuit breaker operation, which can lead to a protection trip or in the longer term, unnecessary wear and tear to primary yard equipment. All PSRs are legacy vintage. The PSR presents another layer of failure risk, and installations where PSRs are present further increase prioritization of replacement.

As further described in TSP Section 2.2.2.4, automation devices' internal components degrade as a function of time, which can alter their performance. Because of the nature of electronic devices, condition cannot be directly measured. Instead, Hydro One uses the ESL of assets as a trigger for replacement assessment, prioritizing devices with a high likelihood of failure. Legacy vintage devices are prioritized, as well as first-generation devices with a high rate of failure or deficiencies based on defect reports, trouble calls, and potential need identifications.

3.0 INVESTMENT DESCRIPTION

Priority for RTU replacement will be given to legacy RTUs and obsolete first-generation modern RTUs that have been identified as problematic based on failure rates or deficiency reports. The extent of the work required at each station depends on the type of RTU replacement. Replacement work can range from a chassis replacement (i.e., replacing the

"brains" of the RTU only), to a full replacement of the RTU and physical I/O board replacement. Also, a PSR may or may not be present for replacement.

The expected pace of replacement is an average of 7 stations per year, or approximately 35 stations over the 2028-2032 planning period. The proposed pacing is consistent with the historical average for this investment. The cost of replacement is based on the historical average cost to replace a legacy RTU at a single station. At this pace, Hydro One expects to completely remove all legacy RTUs by the end of 2028. Subsequently, during the remainder of the 2028-2032 planning period, Hydro One will focus on the replacement of obsolete first-generation modern RTUs.

The replacement levels for the investment over the 2023-2032 planning period have been summarized in Table 2.

Table 2 - RTU Replacement Program

Zone	Component	Plan[1] 23-27	Act/Fcst[2] 23-27	Total 28-32
Hydro One	RTU devices (Stations)	35	35	35

In addition to replacing RTUs, the below materiality capital expenditures (see Section 5.0) for this investment address other automation devices that are obsolete and beyond ESL. Planned expenditures on such devices are immaterial and primarily involve the replacement of gateways and Disturbance Monitoring Equipment (DME), which are further discussed in TSP Section 2.2.2.4.

4.0 OUTCOMES

As a result of the investment, Hydro One will reduce operational risks associated with the operation of equipment that is obsolete, beyond ESL, and deteriorated; reduce outage duration for outages caused by legacy equipment failure; maintain reliability performance

[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.

and regulatory compliance; and prevent loss of control and monitoring of the transmission stations.

4.1 OEB RRF OUTCOMES

Table 3 presents anticipated benefits resulting from the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 3 - Outcome Summary

Customer Focus	• Maintain effective and reliable control and monitoring of bulk stations and load supply stations through strategic replacement of automation equipment beyond ESL. • Reduce equipment failure rate and thereby avoid potential lengthy outages.
Operational Effectiveness	• Improve operational flexibility of the transmission system through the implementation of new standardized automation systems enabling enhanced operational capabilities. • Maintain system performance by reducing risks of outages caused by failure of legacy equipment.
Financial Performance	• Improved financial performance by avoiding costly unplanned reactive replacement of automation equipment. Systematic replacement will avoid the need for reactive replacement of failed units, which can result in costly, lengthy and unplanned restoration time due to part obsolescence.

5.0 EXPENDITURE PLAN

The investment is needed to replace automation equipment at transmission stations across the Hydro One network, which if left unmanaged, may compromise the reliability of transmission grid control and monitoring. Hydro One has planned the investment in a way that strives to complete automation system replacements at a consistent pace, prioritizing legacy and obsolete units that have the greatest risk of failure.

Table 4 summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 4 - Investment Expenditures[3]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	12.0	12.3	12.5	12.8	13.0	62.6
Less Removals	0.4	0.4	0.4	0.4	0.4	2.1
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**11.6**	**11.9**	**12.1**	**12.3**	**12.6**	**60.5**

Table 5 summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 prior rate and 2028-2032 planning periods. Amounts for the 2023-2027 plan and actual/forecast include investment expenditures that were assigned to different ISDs in Hydro One's previous transmission application (EB-2021-0110), as further explained in TSP Section 2.12.

Table 5 - Net Investment Expenditures

Description	Plan[4] 23-27	Act/Fcst[5] 23-27	Total 28-32
RTU Replacement Program[6]	30.7	37.2	40.0
Below Materiality[6]	8.6	12.1	20.5
Total	**39.3**	**49.3**	**60.5**

Over the 2028-2032 planning period, expenditures for the RTU Replacement Program are expected to be higher than the 2023-2027 prior rate period due to higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. During the 2023-2027 prior rate period, actual and forecast expenditures for the RTU Replacement Program are higher than plan due to these inflationary pressures. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept

[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.
[6] "Plan" and "Act/Fcst" for RTU Replacement Program and Below Materiality investments show expenditures previously mapped to Other System Renewal Investments in EB-2021-0110, as further discussed in TSP Section 2.12.

pace with the actual costs that Hydro One and other utilities have experienced during this period.

As noted above, the below-materiality capital expenditures involve the replacement of other automation equipment, specifically gateways and DME. The increase in below-materiality capital expenditures is driven by scope expansion during the 2023-2027 prior rate period to include the replacement of DMEs, which are required for compliance with NERC and NPCC requirements.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO – REACTIVE COMPONENT REPLACEMENT

Alternative 1 involves waiting for devices and systems that are deteriorated and/or beyond ESL to fail and replacing units on a reactive basis. Hydro One has rejected this alternative for the following reasons:

- Under this alternative, assets in deteriorated condition continue to deteriorate and decline, increasing the likelihood of unexpected failures. This reduces the reliability of the grid control network, which is critical to the ability to operate the transmission grid.
- As units become obsolete, replacement units and components will be limited and will eventually become unavailable for purchase. The ability to perform a like-for-like unit replacement, or component replacement, will dwindle as on-hand parts are consumed. Eventually, replacing a unit will incur significant unplanned outage for the design and commissioning of a new device.
- Since these replacements would likely be executed on an emergency basis, this alternative would result in the reprioritization of planned work and inefficient redeployment of resources.
- This alternative limits the ability to account for future requirements and has a high risk of re-work and future costs.

This strategy is likely to increase operating and maintenance costs, decrease equipment performance and could impact the safety of personnel on site, as further described below.

ALTERNATIVE 2: PLANNED COMPONENT REPLACEMENT (RECOMMENDED)

Alternative 2 is the preferred alternative. It involves proactive replacement of obsolete equipment that is beyond ESL before failures occur. This alternative minimizes Hydro One's operational risks and will maintain effective and reliable control and monitoring of the power grid. This preferred alternative provides the following benefits:

- Maintained reliability - Replacing automation system equipment with a high risk of failure will ensure system operations maintain real-time visibility of the network, enabling them to anticipate events or respond appropriately to disturbances.
- Cost reduction - Replacing units before failure will avoid unnecessary wear and tear on primary yard equipment and reduce outages. RTUs allow operators to perform immediate actions in order to maintain system stability; failure of these units will lead to loss of station visibility and an increase in unnecessary equipment operations and outages.
- Safety - Automation system equipment failure will require field personnel to be present at the station to manually control the station. Unmonitored power equipment, such as high voltage transformers and circuit breakers, can create electrical hazards and significant safety risks to field personnel. Proactively replacing obsolete automation system equipment will mitigate this risk.
- Technology Obsolescence - Legacy automation system units and components are no longer available, limiting the availability of replacement units and components which can lead to prolonged and unplanned outages. Bringing equipment up to standard will allow for quick turnaround for problematic installations with availability of replacement units and components.

7.0 EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the investment are: outage constraints, construction execution challenges, customer coordination and procurement challenges. Outage constraints are the major risks associated with the execution of the investment. In some cases, it may be difficult to obtain the project outages necessary for field

commissioning. Cancellations may arise due to higher priority projects or unforeseen system contingencies. The strategy for risk mitigation will be to apply for project outages as soon as practically possible.

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T-SR-20	TRANSMISSION LINE ACCESS AND RIGHT OF WAY PROGRAM INVESTMENT
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	10.6	10.8	11.0	11.3	11.5	55.2

Summary:

This investment is to refurbish, repair, or replace Transmission Access Right-of-Way (TARP) assets where asset condition has deteriorated to a level that poses an elevated risk of failure. The primary driver for the investment is deteriorating asset condition identified through condition assessments and ongoing inspection programs.

Hydro One is prioritizing interventions on non-functional or deteriorated access roads, culverts and bridges. Failure of these assets presents significant Hydro One employee and public safety risk, and limits Hydro One's ability to undertake regular maintenance and emergency responses to damage caused by severe weather conditions or other incidents.

In consideration of these risks, the proposed investment is aimed at sustaining the safe, reliable, and efficient operation of Hydro One's transmission system by proactively addressing asset deficiencies and mitigating the likelihood of unplanned failures.

While the proposed pace of work remains unchanged relative to the forecast for 2023-2027, the investment level for the TARP program has increased in the 2028-2032 planning period due to cost escalation over the 2023-2027 period.

1.0 OVERVIEW

This investment includes the restoration or reconstruction of access infrastructure to Hydro One's TARP assets, including access roads, culverts, and bridges, where deterioration has increased safety risks to Hydro One employees and the public.

Failure of any of these assets presents a significant safety risk to Hydro One employees and the public, particularly in publicly accessible areas. In addition, asset failures can adversely affect the maintenance and operation of the transmission system and may result in longer than usual customer outages.

Hydro One inspects existing access roads, culverts, bridges and undertakes restoration or replacement tasks to support daily maintenance activities and other ongoing sustainment programs such as Wood Pole Replacement, Insulator Replacement, Foundation Clean and Coat, and Foundation Life Extension.

Over the 2028-2032 planning period, the proposed investment plan will refurbish, repair or rebuild approximately 45 access roads, culverts, or bridges. Hydro One has evaluated a range of alternatives, as described in the following sections, and concluded that the proposed pacing of the investment represents the most cost-effective and operationally efficient approach to sustaining the safe and reliable operation of Hydro One's transmission system.

2.0 INVESTMENT NEED

Hydro One maintains a network of on- and off-corridor access roads, bridges, and culverts across Ontario that provide access to approximately 21,000 km of transmission right-of-way lands and associated assets. These access features are used by both Hydro One personnel and the public, particularly snowmobile users in Northern Ontario. Many bridges and culverts are located on Crown land.

Bridges (many of which were historically constructed using timber) and culverts are designed to specific load capacities and naturally deteriorate over time due to aging, environmental exposure, and usage. As deterioration progresses, the load-carrying

capacity of these structures is reduced, increasing safety risks to Hydro One employees and members of the public. Through routine patrols and other planned inspection programs, Hydro One identifies a handful of deteriorated access roads, bridges, and culverts across the province each year.

These conditions cannot be left unaddressed, as failure of access infrastructure poses serious public and worker safety risks, including the potential for injury, restricted emergency access, and operational delays. To mitigate these risks, Hydro One must refurbish or replace identified access roads, bridges and culverts, to maintain safe and reliable access to transmission assets.

Figures 1 and 2 below show deteriorated bridges and culverts.

Figure 1: Deteriorated Bridges near Marathon and Sudbury

Figure 2: Washed out Culvert near Martin River

3.0 INVESTMENT DESCRIPTION

The deteriorated access infrastructure targeted by this investment includes bridges, culverts, and access roads. This program focuses on access assets that are in poor condition as identified through routine inspections and patrol activities as posing elevated safety and operational risks and prioritized to be addressed based on asset condition, criticality, urgency of need by other sustainment programs, and geographic location.

As Hydro One's inventory of bridges, culverts, and other right-of-way assets continues to grow through ongoing identification and cataloguing efforts, investments are managed responsively to address asset needs as they are discovered. Over the 2028-2032 planning period, Hydro One plans to restore or rebuild approximately 45 TARP assets in total which is consistent with 2023-2027 pacing.

In addition to the TARP program, the investment includes the below materiality capital expenditures presented in Section 5.0, which address other assets in the Transmission rights-of-way, primarily consisting of tower member refurbishment and the correction of

substandard clearances. Tower member refurbishment is essential to maintain structural integrity and asset reliability, while substandard clearance corrections are critical to public safety and are required to meet applicable NERC, CSA, and Hydro One standards.

4.0 OUTCOMES

The investment's objectives are to maintain system reliability and to mitigate employee and public safety concerns by addressing 45 bridges, culverts and access roads over the planning period.

4.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Reduce public safety risk associated with deteriorated TARP assets. • Maintain customer reliability by ensuring safe and sufficient access to Hydro One transmission corridors.
Operational Effectiveness	• Maintain system reliability by providing sufficient access for regular maintenance activities and other sustainment programs. • Proactive access restoration reduces the risk of extended emergency restoration time.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence and the TSC to maintain the reliability and integrity of its transmission system.

5.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's forecast net capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	2028	2029	2030	2031	2032	28-32 Total
Gross Capital Expenditures	11.5	11.8	12.0	12.2	12.5	60.0
Less Removals	0.9	0.9	0.9	1.0	1.0	4.8
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**10.6**	**10.8**	**11.0**	**11.3**	**11.5**	**55.2**

Table 3 summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 and 2028-2032 rate periods. Amounts for the 2023-2027 plan and actual/forecast includes investment expenditures that were assigned to different ISDs in Hydro One's previous application (EB-2021-0110), as further explained in TSP Section 2.12.

Table 3 - Hydro One – Net Investment Expenditures

Description	Plan[2] 23-27	Act/Fcst[3] 23-27	Total 28-32
Transmission Lines Right of Way Program	12.8	18.8	23.8
Below Materiality[4]	18.8	16.9	31.4
Total	**31.6**	**35.7**	**55.2**

TARP actual and forecast expenditures in the 2023-2027 period and the 2028-2032 planning period are higher than the 2023-2027 plan, primarily due to higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in the prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs Hydro One and other utilities have experienced during this period.

[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.
[4] "Plan" and "Act/Fcst" for Below Materiality investments show expenditures previously mapped to Other System Renewal Investments in EB-2021-0110.

The increase in below-materiality capital expenditures for the 2028-2032 period is primarily driven by an expansion in the scope of the substandard clearance correction program, which accelerates the remediation of spans identified with clearance deficiencies.

The cost of the proposed investment is influenced by several key factors, including:

- Object type and size: Larger assets such as longer bridges, and larger culverts, require greater quantities of materials, increased labour effort, and heavier or specialized equipment to perform repairs, refurbishment, or removal activities.
- Accessibility to the job site: Costs are affected by whether the job site is easily accessible or located in remote, swampy, or otherwise challenging terrain. Limited access may necessitate vegetation clearing, construction of temporary or permanent access roads, and the use of specialized construction methods. In some locations, work can only be performed under frozen-ground conditions, which further increases costs and scheduling constraints.
- Environmental restrictions: Job sites located within or near environmentally sensitive areas may require additional permitting, environmental assessments, and mitigation measures. These requirements increase both the duration and cost of project execution
- Extent of damage: The severity of asset deterioration directly affects the complexity of the required work. More extensive damage may require specialized equipment, additional materials, and increased labour hours, leading to higher repair costs.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

The Status Quo alternative relies on a reactive approach to managing deteriorated transmission assets, whereby corrective actions are taken only after a failure has occurred. This alternative has been evaluated and rejected for the reasons outlined below.

Reactive restoration would involve repairing failed access roads, bridges, and culverts only after they become unserviceable. This approach has been rejected because deteriorated access infrastructure reduces load-carrying capacity and poses significant safety risks to both the public and Hydro One employees. Inaccessible or unsafe access routes can also prevent timely access to transmission assets for routine maintenance or emergency response.

Emergency restoration of right-of-way access infrastructure would further extend circuit outages and delay restoration activities, increasing the duration of equipment and customer outages.

The Status Quo alternative does not adequately manage safety and reliability risks and results in higher long-term costs due to emergency repairs, inefficient resource utilization, and increased outage impacts. As a result, this alternative is not considered a viable option.

ALTERNATIVE 2: PROACTIVE ASSET REFURBISHMENT AND CORRECTION (RECOMMENDED)

Alternative 2 represents a proactive approach to managing deteriorated transmission assets and is the preferred approach. This alternative involves planned interventions to address asset deficiencies before failures occur, thereby mitigating safety, reliability, and cost risks.

Proactive restoration of transmission right-of-way access involves restoring or rebuilding deteriorated access roads, bridges, and culverts before they become unserviceable. This approach ensures safe access for Hydro One employees and the public, supports routine maintenance and emergency response activities, and reduces the risk of access-related safety incidents. Planned access restoration also minimizes outage durations by avoiding delays associated with emergency access repairs.

Overall, the proactive approach under Alternative 2 provides the most effective means of managing safety and reliability risks, optimizing resource utilization, minimizing outage impacts, and controlling long-term costs. As such, Alternative 2 represents the more

cost-effective, efficient, and prudent undertaking to sustain the safe and reliable operation of Hydro One's transmission system.

7.0 EXECUTION RISK AND MITIGATION

The execution of this investment is subject to several risks, including seasonal access constraints and the acquisition of permits from government agencies. These risks are actively managed through comprehensive planning, detailed scheduling, and coordinated outage management across Hydro One lines of business and with external stakeholders.

During the initial program planning phase, Hydro One conducts a formal risk assessment workshop to identify all known execution risks and develop corresponding mitigation strategies. This proactive approach ensures that risks are identified early and that mitigation measures are incorporated into program delivery plans.

Seasonal access risks are mitigated through advanced planning and scheduling of work during optimal construction windows, including frozen-ground conditions where required. Through these mitigation measures, Hydro One effectively manages execution risks and supports the safe, reliable, and cost-efficient delivery of the proposed investment.

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T-SR-21	**STATIC VAR COMPENSATORS AND SERIES CAPACITORS REPLACEMENT PROGRAM**
Primary Trigger:	Obsolescence & Compliance
OEB RRF Outcomes:	Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	5.0	5.1	5.2	5.3	5.5	26.2

Summary:

This investment involves the replacement of obsolete protection and control (P&C) equipment specifically related to Static VAR Compensators (SVCs) and Series Capacitors (SCs) as necessary to comply with North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) requirements.

SVCs and SCs are primary power equipment that are used to enhance controllability and stability of the power grid. The primary SVC/SC equipment is operational and still within its expected service life, however the P&C equipment for these SVC/SC systems is obsolete and no longer vendor-supported.

The P&C devices are subject to NERC CIP requirements and must be up to date with cybersecurity patches. The primary triggers of the investment are P&C device obsolescence and compliance with NERC CIP requirements. The investment is expected to minimize Hydro One's operational risk, maintain operation of the SVC and SC systems and meet NERC CIP requirements.

1.0 OVERVIEW

Several Hydro One stations make use of technologies that enhance controllability and stability of the power grid. These technologies include Static Var Compensators (SVCs) which provide voltage control to increase line efficiency and Series Capacitors (SCs), which increase power transmission capacity. The SVC and SC are primary power system equipment, and each installation has a dedicated set of devices used for P&C of the system.

There are five Hydro One facilities, one with an SC system and four with an SVC system, each of which were turnkey installations from 2009-2011 including the associated P&C equipment. While the main power system equipment (the SCs and SVCs themselves) is still operational and within expected service life (ESL), the accompanying P&C equipment is obsolete and no longer supported by the vendors, making it impossible to adequately maintain the equipment in accordance with NERC CIP requirements. This investment targets the replacement of obsolete P&C equipment associated with SC and SVC installations.

2.0 INVESTMENT NEED

The P&C equipment associated with SC and SVC installations is a collection of devices that provides the necessary protection and control functions for the main power system equipment. These systems are essential, as the main equipment cannot be safely or reliably operated without them. The P&C equipment associated with the SC and SVC installations at five Hydro One stations has reached the end of its ESL and is no longer supported by vendors. Therefore, the SC/SVC P&C equipment must be replaced.

In addition, all network-enabled P&C equipment installed at Hydro One stations is subject to NERC CIP standards. Hydro One must regularly apply cybersecurity patches to comply with these standards. Since the existing SC/SVC P&C equipment has reached the end of its ESL, it is no longer supported by vendors and cannot be maintained to NERC CIP requirements.

3.0 INVESTMENT DESCRIPTION

This investment entails the replacement of P&C devices associated with the SC installation at one Hydro One station and SVC installations at another four Hydro One stations. The primary power equipment (i.e., the SVC or SC) does not currently require replacement and is not included in this investment. The work to replace the P&C devices at each site is expected to take two to three years in order to coordinate scheduling between vendor availability, commissioning procedures and outage availability. Work on the first site is expected to start in 2026, however, the first site is not expected to be placed in service until 2028. Hydro One will stagger the start of each replacement so that only two are executing in parallel. Hydro One plans to in-service one site every other year starting in 2028, completing 3 stations by the end of the 2028-2032 planning period.

4.0 OUTCOMES

As a result of this investment, the SVC and SC systems at the five Hydro One stations will adhere to NERC CIP requirements and will be maintainable to the required compliance standard for the expected life cycle of the new equipment. The replacement equipment will operate with the same functionality as the original installation.

4.1 OEB RRF OUTCOMES

Table 1 below presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcome Summary

Operational Effectiveness	• Maintain system performance by reducing risks of bypassing the equipment caused by failure of legacy P&C equipment.
Public Policy Responsiveness	• Cybersecurity patch management of network connected devices is required for compliance with NERC CIP.

5.0 EXPENDITURE PLAN

The investment will replace P&C devices at five Hydro One stations. The estimated costs are based on high level vendor quotes for full P&C system replacement.

Table 2 below summarizes Hydro One's actual and forecast net capital expenditures for the 2023-2027 rate period and the 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	-	4.2	5.3	5.4	5.5	5.6	5.7	27.6
Less Removals	-	0.1	0.3	0.3	0.3	0.3	0.3	1.4
Less Capital Contributions	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	-	4.1	5.0	5.1	5.2	5.3	5.5	26.2

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

Alternative 1 is to not replace the P&C equipment and continue to operate the SVC/SC systems as they are. The SVC/SC P&C systems are at the end of their ESL and are no longer supported by the vendor. Continued operation will increase the likelihood of unexpected failures. If the P&C system fails and cannot be repaired, the primary SVC or SC equipment will be bypassed until the P&C equipment is replaced. This negates the benefits provided by the main SVC or SC equipment and renders them useless. In addition, because the existing P&C equipment is no longer supported by vendors, Hydro One cannot maintain them in accordance with NERC CIP requirements.

[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.

ALTERNATIVE 2: P&C REPLACEMENT (RECOMMENDED)

The recommended alternative is to replace the P&C equipment as described under this investment. This will minimize Hydro One's operational risk by replacing equipment that is beyond its ESL and will allow the continued operation of the SVC and SC systems with modern and vendor supported protection and control devices. Subsequently, it will allow Hydro One to also maintain the equipment with software updates and security patches in accordance with NERC CIP requirements.

7.0 EXECUTION RISK AND MITIGATION

Execution of this work is dependent on system outage availability and vendor resource availability. There is risk to the completion timeline due to these dependencies. To mitigate these risks, the project team will coordinate with vendor teams and outage schedulers early and often to determine possible outage windows and maintain project schedule.

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T-SR-22	**TRANSMISSION STATION COMPONENT REPLACEMENT**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Net Cost	76.0	78.8	82.7	85.3	87.7	410.3

Summary:

This investment involves the replacement of individual transmission station assets that are in poor condition. The primary trigger of the investment is deteriorated asset condition. The investment is expected to mitigate the risk of reduced supply reliability and customer outages resulting from equipment failures. It also supports Hydro One's continued compliance with regulatory obligations while mitigating safety, system reliability, and environmental risks.

1.0 OVERVIEW

The Transmission Station Component Replacement investment manages asset-failure related risks to health and safety, operational effectiveness, and system reliability through the replacement of individual poor condition assets at transmission stations.

The scope of the investment comprises the proactive replacement of poor condition transformers, breakers, civil infrastructure, and other station assets such as switches, capacitor banks, insulators, batteries, chargers, cables, instrument transformers, arresters, gas insulated switchgear (GIS/GIL), grounding systems, and low voltage station service equipment. These investments address localized asset risks while preserving the remaining useful life of the other healthy station components. This investment does not include the replacement or renewal of automation and protection components, such as station protection relays, other protection equipment, or Remote Terminal Units (RTU) and related automation devices, as described in ISDs T-SR-10, T-SR-21, and T-SR-19, respectively.

Failure to proceed with these replacements would leave poor condition assets in service, increasing the likelihood of equipment failure, safety hazards, environmental impacts, and unplanned outages for customers. It could also create operational constraints such as bottled generation, reduced transfer capability, and restricted power flows. As a licensed transmitter, Hydro One must maintain compliance with IESO planning and operating criteria and the Transmission System Code; timely replacement of deteriorated assets is essential to meet these obligations and ensure safe, reliable service. This investment helps ensure that Hydro One can maintain system reliability, safety, and compliance by swiftly addressing deteriorated equipment while preserving the value of healthy station components.

This investment is complementary to Hydro One's integrated station investments and comprises the planned replacement of poor condition and obsolete assets that are not included in the integrated station projects described in ISDs T-SR-01, T-SR-02, or T-SR-03.

2.0 INVESTMENT NEED

Leaving poor condition station assets in-service poses an increased risk of failure or risk of failing to execute operations as intended. When repairs are not cost effective or technically feasible, poor condition assets must be replaced.

Failed power transformers may catch fire resulting in safety hazards, extensive damage, and/or oil spills, an example of which is set out in Figure 1. Transformer condition is determined by industry standard diagnostic testing which includes routine oil testing, online dissolved gas analysis (DGA) monitoring, and other maintenance inspections. The predominant indicator of transformer condition is irreversible insulation deterioration. While the transformer oil can be drained and refilled, the cellulose layer of insulation cannot be replaced. Once the cellulose layer has aged and degraded, the transformer requires replacement.

Figure 1: Finch TS Transformer Failure

Poor condition breakers may fail to operate when needed, resulting in system operation and stability issues or cause impact to other connected equipment. Breaker condition is determined through diagnostic testing and other routine inspections. As discussed in TSP Section 2.2.2.2, circuit breakers use a variety of interrupting mediums including oil, air, and sulfur hexafluoride (SF_6) gas. In the case of air and SF_6, the interrupting mediums are kept at high pressure to effectively quench electric arcs during breaker operation. As breakers age their O-rings and gaskets slowly degrade causing the oil, air, or SF_6 gas to leak out and lower the breaker's pressure. Concurrently, leaks create a path for moisture ingress. These conditions reduce the dielectric strength in the breaker which reduces its

arc quenching capability and increases the potential for internal flashover, which could lead to an explosive failure of the breaker, as shown in Figure 2. Some models of SF_6 breakers have known issues with leaks, including a subset of the population for which repairs are not effective, thereby requiring replacement.

Figure 2: Thornton TS Breaker Failure

A portion of the instrument transformer fleet poses a safety risk to staff or operational risk to other equipment in the event of failure due to obsolete designs without explosion-resistant features. The aftermath of such an event can be seen in Figure 3. Targeting the replacement of such obsolete designs will reduce safety and operational risks. Another portion of the population does not meet current IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) voltage requirements, specifically in the northern Ontario 115kV system. The equipment is operated within its limited capability, which could limit IESO operational flexibility and should be replaced.

Figure 3: Explosive Failure of a Current Transformer

Insulators, which mechanically support live components and provide electrical clearance, are in numerous quantities throughout all transmission stations. Approximately a third of Hydro One transmission stations contain a subset of insulators that have known design defects and have a higher risk of failure, as shown in Figure 4. This risk is assessed based on station age, past renewal projects, and site surveys. On average there are 100 insulator failures inside stations annually, with 10% causing an outage. Half of the failures occur during switching operations, which presents safety risks to staff who could be struck by falling equipment when the insulator breaks. Targeting the replacement of poor condition and high-risk insulators will reduce the number of outages and potential safety concerns.

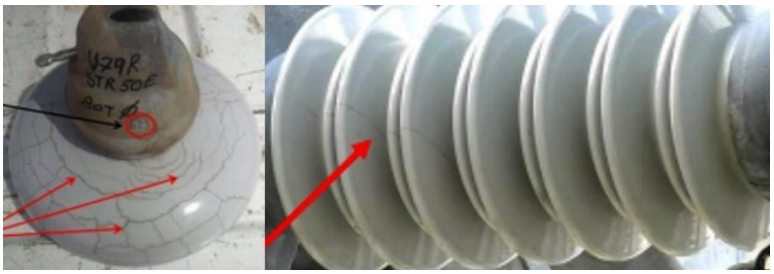

Figure 4: Insulators with Cracks & Cement Growth

Disconnect switches are used to electrically isolate sections of the transmission system for maintenance, safety, and other operational requirements. Hydro One has over 15,000 medium and high voltage switches, with approximately 10% in poor condition, including

3.5% of the fleet with inherent design defects and high failure rates, and 6.5% with outstanding defects, ongoing performance issues, or insufficient ratings due to system growth or network changes which can lead to failure from overheating, as shown in Figure 5. Condition is assessed through visual and Thermovision inspections and during switching operations. The typical mode of failure is a mechanical problem requiring it to be wired shut or bypassed. Providing isolation at that point then requires a much wider outage to the next set of functioning switches, which results in additional elements being taken out-of-service and potentially reducing system capacity and reliability. If this is not acceptable to system operators due to increased risk, equipment limitations, or impacts to customers for the outage period, then manual disconnection and later reconnection of the bus must be added to the work which further increases cost and extends the outage. Non-functioning switches also increase system reliability risk through wider outages, cancelled maintenance, impact to customers, delays and added cost to capital projects. Poor condition switches that have inherent design flaws, insufficient ratings, obsolete defective units without spare parts, or units requiring uneconomical repairs require replacement.

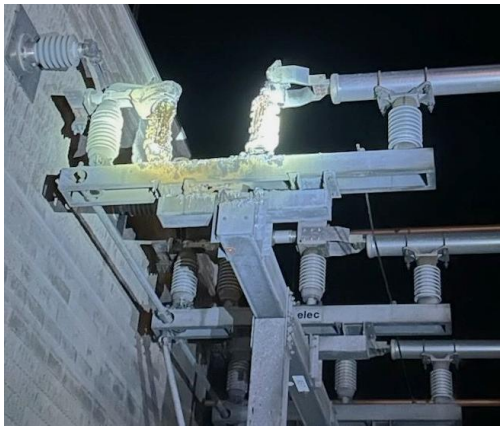

Figure 5 - Failed Switch

AC and DC station service systems in transmission stations provide power to the main station equipment, protection systems, and auxiliary equipment such as fans, pumps, heating, lighting, etc. The Northeast Power Coordinating Council (NPCC) requires Bulk Power System (BPS) stations to have dual sources of AC supply and the ability to transfer the entire station service load to either source. BPS stations are also required to have two DC power systems to supply independent protection groups along with a transfer

arrangement between supplies. Transfer schemes receive periodic diagnostic and functional testing to assess condition. Approximately 20% of stations contain poor condition and/or station service equipment with inherent design issues that may pose health and safety risks. As shown in Figure 6, poor condition transfer schemes that cannot be cost-effectively repaired or those with performance or design issues may pose health and safety risks to workers operating the equipment and require replacement.

Figure 6: Poor Condition Station Service Transfer Scheme

Transmission station batteries and battery chargers are an integral component of protection systems. Lead-acid batteries, the main battery type used in protection systems, naturally lose capacity over time due to irreversible aging mechanisms such as sulfation and positive grid corrosion. The TSC and NPCC standards require transmitters to ensure that batteries have enough capacity to operate the station for prescribed lengths of time in the event of the loss of a charger or AC supply. Batteries and chargers with insufficient capacity or those in poor condition pose a risk to safe and reliable operation and are required to be replaced to ensure the reliability of protection systems.

Hydro One routinely visually assesses the condition of transmission station civil and environmental infrastructure, such as drainage systems, yard surface/subsurface, access roads, structural footings and foundations, spill control systems, trench covers, and perimeter fencing. Many stations have been found to exhibit advanced deterioration of these critical infrastructure components, examples of which are shown in Figures 7-8. If

left unaddressed, there will be increased risk of equipment and structural failure, safety hazards due to increased step-and-touch potential, restricted site access for maintenance and operations, and environmental impacts due to uncontained oil spills in the event of a transformer failure.

Figure 7: Damaged Access Road

Figure 8: Failing Concrete Footer

Wildlife contact with transmission station equipment is a significant source of customer interruptions and equipment outages, contributing up to 20-30% of T-SAIDI$_{mc}$ (Transmission System Average Interruption Duration Index for Multi-Circuit Supplied Delivery Points). To address this, a capital program is required to target stations identified with recurring wildlife incidents and design vulnerabilities and includes the installation of cover-up and wildlife control fencing (Figures 9-10), screening, pole and structure deterrents, habitat modifications, and other civil works.

Figure 9: Wildlife Control Fencing

Figure 10: Wildlife Coverup

3.0 INVESTMENT DESCRIPTION

The investment targets the replacement of individual poor condition station assets that are not included within larger integrated station projects as described in ISDs T-SR-01, T-SR-02 and T-SR-03. The major asset groups addressed under this investment include transformers and breakers, along with other station components such as insulators, instrument transformers, disconnect switches, capacitor banks, batteries, chargers and station service equipment. The investment also addresses civil infrastructure, including access roads, foundations, spill-control systems and wildlife-mitigation measures.[1] Factors driving the renewal of specific asset groups are described below for each asset group, in Section 2.0 above, and in TSP Sections 2.2.2 and 2.2.3.

3.1 TRANSFORMERS AND BREAKERS

During the 2023-2027 period, Hydro One planned to renew 8 transformers and 48 breakers under this program. As described in TSP Section 2.9, Hydro One was required to reprioritize capital expenditures due to increasing demand for non-discretionary and externally driven investments, coupled with significant cost escalation. Based on actuals and forecast for the 2023-2027 period, Hydro One expects to complete 1 transformer and 25 breaker replacements under this program.

[1] This investment does not include the replacement or renewal of automation and protection components, such as station protection relays, other protection equipment, and RTU and related automation devices, as described in ISD T-SR-10, ISD T-SR-21, and ISD T-SR-19, respectively.

The proposed pacing in the 2028-2032 planning period for transformer and breaker component replacement programs will cover 8% of poor condition transformers and 24% of poor condition breakers. The increase in transformer replacement is required to address deferred work from the 2023-2027 rate period and the growth in the proportion of poor condition transformers. As described in TSP Section 2.2.1, poor-condition transformers increased from 16% in 2016 to 29% in 2025, reflecting a materially aging fleet and a growing reliability risk.

The increase in breaker replacement reflects pacing consistent with historical levels when accounting for replacements through the complementary integrated stations investments described in ISD T-SR-01, T-SR-02, and T-SR-03.

3.2 OTHER STATION ASSETS

Other station asset component replacement programs target various types of components that are in poor condition, obsolete, or beyond expected service life (ESL), and are therefore in need of replacement or renewal, as further described in TSP Section 2.2.3. As noted above, other station assets include a broad array of station components, such as batteries, chargers, low voltage station service equipment, capacitor banks, insulators, instrument transformers, GIS, cables, and disconnect switches.

During the 2023-2027 period, the volume of other station asset replacements was reduced relative to Plan to accommodate the need to ramp up certain types of other station component replacement work which have higher replacement costs due to more complex and costly work. This altered work scope put pressure on available capital funding. To contain total investment costs within the capital envelope, Hydro One reduced overall work volume for the 2023-2027 period. For example, there was an increase in replacement expenditures for AC and DC station service components which are more costly than instrument transformer replacements. Further cost pressures arose due to higher and sustained inflation experienced by Hydro One over the 2023-2027 period, which further constrained work volumes.

The proposed pacing for the replacement and renewal of other station assets is higher than the historical average to account for the number of assets that are in poor condition,

obsolete, or beyond ESL. As discussed above in section 2.0, over 30% of stations have insulators that are in poor condition or have known design deficiencies, over 20% of stations have poor condition and obsolete low voltage station service equipment that poses both health and safety and reliability risks, over 30% of capacitor banks are in poor condition or are obsolete with spare parts not readily obtainable, 10% of disconnect switches are in poor condition or obsolete, and 3-5% of station batteries and chargers require replacement annually due to natural performance degradation. The proposed pacing for these programs targets the worst condition and highest risk equipment for replacement.

3.3 CIVIL INFRASTRUCTURE

The civil infrastructure component replacement program covers installation of wildlife coverup at stations with recurring wildlife incidents, spill control system replacement and upgrades, and replacement of deficient station site civil and environmental infrastructure. During the 2023-2027 period, similar pressures arose for these programs as noted above for other station assets. The volume of civil infrastructure replacement and renewal work was reduced relative to Plan to accommodate the need to ramp up certain types of other civil infrastructure work which have higher replacement costs due to more complex and costly work. This altered work scope put pressure on available capital funding, requiring Hydro One to temporarily reduce overall civil infrastructure work volumes for the 2023-2027 period. The proposed pacing for the renewal of station civil infrastructure for the 2028-2032 planning period is needed to address the deferred work and reflects scope expansion to address recurring wildlife incidents at targeted stations.

The planned investment pacing for the 2028-2032 planning period includes the repair of deficient civil infrastructure at 15% of stations, 10 spill control system upgrades which will address approximately one-third of poor condition systems, and the installation of wildlife coverup in 12% of stations.

A summary of the target number of replacements is shown in Table 1.

Table 1 - Investment Description – Volume of Work

Zone	Asset	Plan[2] 23-27	Act/Fcst[3] 23-27	Total 28-32
Hydro One	Transformers (% of fleet)	8 (1.1%)	1 (0.3%)	16 (2.2%)
	Breakers (% of fleet)	48 (1.0%)	25 (0.5%)	97 (2.0%)
	Other Station Assets (% of fleet)	384 (1.5%)	311 (1.2%)	410 (1.6%)
	Civil Infrastructure	71	63	120
	Below Materiality:			
	Transformer Cooling System Refurbishment	47	62	50
	Transformer DGA Monitors	69	37	50
	Battery Monitoring Systems	60	31	50

4.0 OUTCOMES

Hydro One aims to achieve the following outcomes as a result of the investment:

- Maintain system and customer reliability by replacing poor condition transformers, breakers, and other station components.
- Reduce the likelihood of employee and public safety incidents related to failing station assets and infrastructure.

4.1 OEB RRF OUTCOMES

Table 2 below presents anticipated benefits as a result of the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

[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) amounts.

Table 2 - Outcomes Summary

Customer Focus	• Reduce public safety risk associated with station asset and infrastructure failure • Maintain customer reliability by replacing poor condition station assets
Operational Effectiveness	• Maintain system reliability by replacing poor condition station assets prior to failure

5.0 EXPENDITURE PLAN

Table 3 below summarizes Hydro One's aggregate forecast net capital expenditures for the 2028-2032 planning period.

Table 3 - Hydro One – Investment Expenditures[4]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	76.8	79.4	83.1	85.7	88.2	413.3
Less Removals	0.9	0.7	0.5	0.5	0.5	3.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**76.0**	**78.8**	**82.7**	**85.3**	**87.7**	**410.3**

Table 4 below summarizes Hydro One's planned and forecast net capital expenditures for the 2023-2027 and 2028-2032 rate periods. Amounts for the 2023-2027 Plan and actual/forecast have been adjusted to include investment expenditures that have been assigned to different ISDs for the 2028-2032 planning period compared to Hydro One's previous Application (EB-2021-0110), as further explained in TSP Section 2.12. Forecast expenditures for the investment are based on historical costs.

[4] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 4 - Hydro One – Investment Subprogram Expenditures

Component Replacement Program Description	Plan[5] 23-27	Act/Fcst[6] 23-27	Total 28-32
Transformer Component Replacements	80.7	35.5	155.7
Breaker Component Replacements	25.0	15.9	33.3
Other Station Component Replacements	44.5	75.2	137.1
Civil Infrastructure Replacements	10.5	19.3	48.8
Below Materiality	21.6	19.4	35.5
Total	**182.4**	**165.2**	**410.3**

Over the 2023-2027 rate period, Hydro One expects actual and forecast expenditures to be lower than Plan by $17.2M. The decrease is primarily driven by lower than expected expenditures for transformer and breaker component replacements, at $45.2M and $9.1M below Plan, respectively. Expected decreases in these programs are partially offset by expected increases in other station component and civil infrastructure replacements expenditures of $30.7M and $8.7M, respectively.

The decrease in expenditures for transformer and breaker replacements resulted from reprioritization during the 2023-2027 period to accommodate increasing demand for non-discretionary and externally-driven investments.

Increases in other station component replacement and civil infrastructure expenditures reflect Hydro One's need to ramp up certain types of work which have higher replacement costs due to more complex and costly work. For example, there was an increase in replacement expenditures for AC and DC station service components which are more costly than instrument transformer replacements. Additionally, a focused effort was needed to replace station service transformers in over 20 stations that are in poor condition,

[5] "Plan" refers to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110. "Plan" includes expenditures mapped to T-SR-09 in EB-2021-0110.
[6] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures. "Act/Fcst" includes expenditures mapped to T-SR-09 in EB-2021-0110.

beyond ESL, and/or required replacement under federal regulations due to high PCB content.

Also contributing to the variance are higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historic material cost escalation trends are described in SPF Section 1.8.3, including power transformers, which have increased by 115% on average since 2020.

For the 2028-2032 planning period, Hydro One forecasts expenditures of $410.3M, approximately $245.1M higher than the 2023-2027 actuals and forecast. The increase is primarily driven by two factors:

1. The higher replacement and renewal pacing required for transformers, breakers, other station assets and civil infrastructure, as described in Section 3.0 above; and
2. higher and sustained inflationary pressures that have increased the cost of replacement and renewal work.

Forecast transformer replacement expenditures are higher in the 2028-2032 planning period to address work deferred from the 2023-2027 rate period, the growing proportion of transformers in poor condition, and increased replacement cost.

Forecast expenditures for other station assets and civil infrastructure are also higher than historical levels, reflecting both inflationary pressures and the increased volume of more complex work required to address assets that are in poor condition, obsolete or beyond ESL, as discussed in Sections 2.0 and 3.0 above.

For civil infrastructure, the increase is largely driven by scope expansion of the program to address recurring wildlife incidents at targeted stations, together with additional renewal needs for deficient site infrastructure and spill control systems.

6.0 ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred option.

ALTERNATIVE 1: REACTIVE COMPONENT REPLACEMENT

Reactive component replacement involves waiting for transformers, breakers, or ancillary equipment in deteriorated condition to fail before replacing them on a reactive basis. Hydro One does not intentionally run transmission assets to failure given their criticality to the integrity of the transmission system and the significant reliability, safety and environmental impact associated with their failures. This alternative would be more costly for both Hydro One and impacted customers. Hydro One has rejected this alternative for the following reasons:

- Assets in deteriorated condition will continue to deteriorate, thereby increasing the likelihood of unexpected failures. When a critical asset fails, redundancy can be lost for several months. In the case where a subsequent failure of a companion unit occurs, the consequences could be significant to the transmission system. Such a failure would be prolonged and result in extended equipment and customer outages which will subsequently negatively affect the Transmission System Average Interruption Duration Index (SAIDI) and Transmission System Average Interruption Frequency Index (SAIFI) performance.
- At the majority of connection stations, a significant proportion of station load may become stranded, meaning the load cannot be immediately transferred to another station or transferred within the distribution system. A failure at a vulnerable station with stranded load would result in extended power outages until an emergency measure is implemented.
- An increased likelihood of unexpected failures would lead to increased environmental risk due to the possibility of a release into the environment during a failure event.
- An increased likelihood of unexpected failures would lead to increased safety risk due to the possibility of a failure event being catastrophic in nature.
- Since these replacements would likely be executed on an emergency basis, it would result in constant reprioritization of planned work and inefficient redeployment of resources.

- This alternative limits the ability to account for future requirements and has a high risk of re-work and future additional costs.
- This strategy is likely to increase operating and maintenance costs, decrease equipment performance and may impact the safety of personnel on site.

ALTERNATIVE 2: PLANNED REPLACEMENT OF COMPONENTS (RECOMMENDED)

The planned replacement of components is the recommended option. Unlike reactive replacements, planned station renewal allows the work to be completed through coordinated outage plans, reducing the number of equipment outages and mitigating the safety and reliability risks associated with continued deterioration or in-service failure.

In addition to mitigating the risks and consequences stemming from equipment failures, planned replacements have the advantage of optimizing system and equipment outages, as well as being adaptable to supply chain lead times.

7.0 EXECUTION RISK AND MITIGATION

Risks that can impact the completion of transmission station component replacements include:

- Outage constraints: Planned outages are required to replace assets and may involve individual assets, sections of a station, or the entire station. Hydro One plans and coordinates outages to minimize impacts on customers while providing construction and commissioning staff with the access required to complete the work.
- Resource constraints: Projects in the same geographical location may require the same construction and commissioning resources. Hydro One coordinates project schedules and resource requirements to manage competing demands for these resources.
- Construction execution challenges: Existing station equipment may require retrofits to accommodate new assets because station designs and equipment standards have evolved. Significant design and construction may also be required where assets cannot be replaced in the same physical location due to space constraints, outage requirements or safety considerations.

- Customer coordination: Hydro One coordinates with customers to manage required outages and minimize customer impacts.
- Procurement challenges: Equipment procurement lead times can be long. Hydro One engages vendors at appropriate times in the planning process to ensure sufficient lead time to obtain major equipment.

T-SS-06	SOUTHWEST GTA TRANSMISSION REINFORCEMENT
Primary Trigger:	Regional Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	9.0	12.5	8.1	3.0	0.0	32.7

Summary:

This investment is required to reinforce the transmission system between Richview TS and Manby TS to increase supply capacity in the South-West GTA pursuant to the recommendations of the IESO in the 2019 Toronto Integrated Regional Resource Plan (IRRP) and the 2020 Toronto Regional Infrastructure Plan (RIP). The need was subsequently reaffirmed by the IESO in the 2021 Toronto IRRP Addendum, the 2025 Toronto IRRP, and the 2026 Toronto RIP.

As detailed in the 2019 IRRP and 2020 RIP, the execution of this investment was planned over two phases.

Stage 1 of the work involved rebuilding an existing idle double-circuit 115 kV transmission line as a new double-circuit 230 kV transmission line within the existing corridor and modifying and reconfiguring the existing circuits to incorporate the new line. Stage 1 was placed in service in 2026.

Stage 2 of this investment involves station work to be undertaken during the 2028-2032 period, to terminate the new lines at Manby TS and connect them to existing circuits between Claireville TS and Richview TS at the Richview TS end. Consistent with the need date expressed in the 2025 Toronto IRRP, Hydro One expects to place the Stage 2 station work in service in 2031.

This investment is non-discretionary. When an IRRP or RIP recommends expansions or reinforcements within a targeted in-service timeline, if the recommended work involves

modifications to Hydro One's existing facilities or the construction of new facilities where Hydro One has been recommended as the entity to develop, seek approvals for and/or to build new assets, then it is incumbent upon Hydro One to implement the recommended solution by incorporating it into its investment plans, undertaking the relevant development and scoping work, applying for and securing required approvals, procuring the necessary land rights and equipment, and putting the recommended facilities into service in a manner that delivers sustained compliance with the reliability standards and criteria underlying the established need. For these reasons, an investment in a regional planning project such as the Southwest GTA Transmission Reinforcement is non-discretionary. Moreover, as a licenced transmitter Hydro One is obligated to provide facilities that maintain the reliability and integrity of its transmission system and reinforce or expand the system as required to meet anticipated load growth. Failing to proceed with this investment would not allow Hydro One to meet its obligation as it would result in inadequate transmission capacity to supply load growth in the South-West GTA area.

1.0 INVESTMENT NEED

This investment is required to increase the transfer capability between Richview TS and Manby TS to support continued load growth in the South-West GTA, as identified in the 2020 Toronto RIP[1] and the 2019 Toronto IRRP[2]. The need was subsequently reaffirmed by the 2021 Toronto IRRP Addendum,[3] the 2025 Toronto IRRP,[4] and the 2026 Toronto RIP.[5]

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the western half of the City of Toronto. It also supplies load in the southern Mississauga and Oakville areas via Manby TS. At the time of the 2020 Toronto RIP and 2019 Toronto IRRP, the corridor had two 230 kV double-circuit lines (R1K/R2K and R13K/R15K) and one idle 115 kV double-circuit line. The 2020 Toronto RIP and the 2019 Toronto IRRP identified the need to reinforce the transmission system on the South-West GTA transmission corridor by rebuilding the existing idle 115 kV transmission line as a new 230 kV double circuit line and connecting it to Manby TS and Richview TS.

As detailed in the 2019 IRRP and 2020 RIP, the execution of this investment was planned over two phases.

The Stage 1 line work, which was placed in service in 2026, involved rebuilding an existing idle double-circuit 115 kV transmission line as a new double-circuit 230 kV transmission line, connecting the new 230 kV conductors in parallel with the existing circuits, modifying

[1] 2020 Toronto Regional Infrastructure Plan, March 6, 2020, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/TorontoRegionalInfrastructurePlan_Mar62020.pdf
[2] 2019 Toronto Integrated Regional Resource Plan (IRRP), August 9, 2019, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/Toronto-IRRP-Report-Final-08092019.pdf
[3] Toronto IRRP Addendum: Richview x Manby 230 kV Circuit Upgrades, November, 2021, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/Toronto-2021-Addendum.pdf
[4] Toronto Integrated Regional Resource Plan, October 31, 2025, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/toronto-IRRP-Report-20251031.pdf
[5] 2026 Toronto Regional Infrastructure Plan, May 27, 2026, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto-RIP-Report-May-2026.pdf

and reconfiguring the existing circuits and modifying the protection and control settings at Richview TS and Manby TS to incorporate the new line.

This investment is comprised of the Stage 2 station work, to be completed during the 2028-2032 period, which will terminate the new lines at Manby TS and connect them to existing circuits between Claireville TS and Richview TS at the Richview TS end. Hydro One expects to place Stage 2 in service in 2031, consistent with the need date expressed in the 2025 Toronto IRRP.

When an IRRP or RIP recommends expansions or reinforcements within a targeted in-service timeline, if the recommended work involves modifications to Hydro One's existing facilities or the construction of new facilities where Hydro One has been recommended as the entity to develop, seek approvals for and/or build new assets, then it is incumbent upon Hydro One to implement the recommended solution by incorporating it into its investment plans, undertaking the relevant development and scoping work, applying for and securing required approvals, procuring the necessary land rights and equipment, and putting the recommended facilities into service in a manner that delivers sustained compliance with the reliability standards and criteria underlying the established need. For these reasons, an investment in a regional planning project such as the Southwest GTA Transmission Reinforcement is non-discretionary. Moreover, as a licenced transmitter, Hydro One is obligated to provide facilities that maintain the reliability and integrity of its transmission system and reinforce or expand the system as required to meet anticipated load growth. Failing to proceed with this investment would prevent Hydro One from meeting its obligation and would result in inadequate transmission capacity to supply load growth in the South-West GTA area.

2.0 INVESTMENT DESCRIPTION

The proposed investment consists of the Stage 2 station work needed to reinforce the transmission system on the South-West GTA transmission corridor, which is comprised of the following:

- Remove and unbundle the parallel connections made in Stage 1 and terminate the two new circuits into the Manby TS 230 kV switchyard;

- Connect new circuits at the Richview TS end to two of the existing 230 kV transmission circuits from Claireville TS to Richview TS; and
- Add and/or modify protection and control equipment at Richview TS, Claireville TS and Manby TS to incorporate the two new circuits.

A map showing the project location is provided in Figure 1 below.

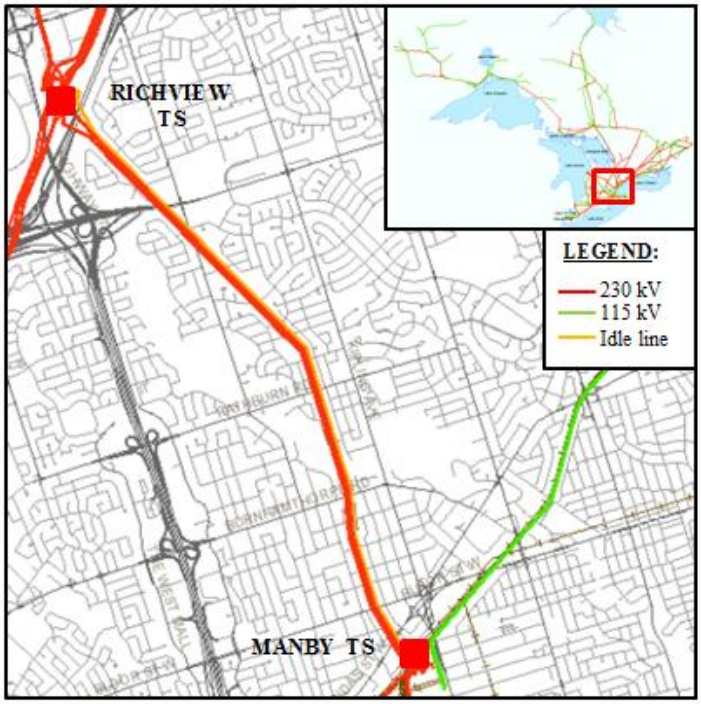

Figure 1: Map of project location

The System Impact Assessment and Customer Impact Assessment have been completed and confirm that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission customers.

3.0 OUTCOMES

This investment will provide the required increase in supply capacity to support future load growth and maintain reliability for customers in Toronto and the southern Mississauga/Oakville areas.

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 - Outcomes Summary

Customer Focus	• Ensure adequate supply capacity to support future load growth.
Operational Effectiveness	• Increase operating flexibility of the transmission system by providing increase in transformation capacity.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License and the TSC to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth in response to recommendations from the regional planning process.

4.0 EXPENDITURE PLAN

This investment is non-discretionary because it has been identified through the Regional Planning process by the Regional Planning Study Team consisting of Hydro One, the IESO and local LDCs, as the recommended investment to address necessary transmission system reinforcement on the South-West GTA transmission corridor. The project costs, as presented in the table below, will be recovered from the network rate pool as these 230 kV facilities are network assets.

Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 rate period.

Table 2 - Hydro One - Investment Expenditures[6]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	9.0	12.5	8.1	3.0	0.0	32.7
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	**9.0**	**12.5**	**8.1**	**3.0**	**0.0**	**32.7**

[6] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 3 below summarizes Hydro One's forecast capital expenditures and prior rate period expenditures as well as the maturity of the project at the time of filing, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of the level of upfront development.

Table 3 - Hydro One - Net Investment Expenditures

Investment Name	Prior Type	Prior Proj. Total[7]	Prior In-Service Year	Type	Proj. Total	In-Service Year
Southwest GTA Transmission Reinforcement – Stage 2 (Stations)	P	30.0	-	P	32.7	2031

This investment (i.e. Stage 2 station work) is expected to be placed in service in 2031 at a forecast project total of $32.7M. The expected in-service date is consistent with the 2025 Toronto IRRP.

A detailed variance summary of the individual investment for the Stage 1 lines work is provided in TSP Section 2.9, Attachment 2.

5.0 ALTERNATIVES

This investment is non-discretionary and is needed to ensure reliable supply for customers in Toronto and the southern Mississauga/Oakville areas, as well as to support future load growth. There are no alternatives specific to the Stage 2 station work. The Stage 2 station work is required to enable the transmission system reinforcement between Richview TS and Manby TS and to increase supply capacity in the South-West GTA, consistent with the recommendations in the 2019 and 2025 Toronto IRRP, as well as the 2020 Toronto RIP.

[7] "Prior Proj. Total" refers to the project total related to Hydro One's revised capital expenditure and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.

6.0 EXECUTION RISK AND MITIGATION

The availability of outages required to execute the work is a normal project risk that may affect the timely completion of the investment. This risk will be mitigated by setting a schedule that aligns with outage availability.

T-SS-09	**WEST OF LONDON TRANSMISSION REINFORCEMENT**
Primary Trigger:	Bulk Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	55.4	42.8	28.9	0.5	0.0	127.7

Summary:

This investment involves performing station expansion and upgrades required at terminal network stations to facilitate the connection of new transmission circuits, which will increase the transfer capability of the bulk transmission system east of Chatham and thereby allow the IESO to more effectively dispatch generation resources within the system to meet demand in the Lambton-Sarnia area for intra-zonal and provincial supply. The investment is expected to provide the required increase in supply capacity to support future load growth and maintain reliability for the Windsor-Essex region over the mid- to long-term, as recommended by the IESO through its bulk system planning processes.

This investment covers the second stage of a two staged investment commenced in 2022 pursuant to Orders in Council (OIC) issued by the Minister of Energy and Mines (the Minister) on March 31, 2022. OIC 876/2022 designated both stages of the investment as priority transmission projects in accordance with s. 96.1 of the *Ontario Energy Board Act, 1998*. OIC 875/2022 required the OEB to amend Hydro One's transmission licence to include a requirement that Hydro One proceed to develop and seek approvals related to both stages of the investment. Hydro One's Transmission Licence was amended by the OEB, effective April 6, 2022 (EB-2022-0142), by adding the requirements for Hydro One to proceed with both stages of the investment.

Stage 1 is comprised of the station work needed to connect a new double-circuit 230 kV transmission line between Lambton Transformer Station (TS) and Chatham Switching Station (SS) known as the St. Clair Transmission Line. The new double-circuit 230 kV transmission line is expected to be owned by and included in the rate base of an Affiliated Transmission Partnership (ATP) and therefore will not form part of Hydro One's rate base. Stage 1 is expected to be placed in service in 2027.

For the 2028-2032 period, this investment covers the remaining Stage 2 station work, which is needed to connect a new single-circuit 500 kV transmission line between Lakeshore TS and Longwood TS, and includes minor grounding upgrades at six remote stations due to changes in fault levels resulting from the new transmission line. The expected in-service date for the Stage 2 station work is 2030. The new single-circuit 500 kV transmission line is expected to be owned by and included in the rate base of an ATP and therefore is not included in this application and will not form part of Hydro One's rate base. As such, the capital expenditures associated with any lines work has been excluded from the 2028-2032 forecast.

At the time of Hydro One's prior transmission rate application (EB-2021-0110), the Stage 2 scope of work was anticipated to involve the connection of a new double-circuit 230 kV transmission line at Longwood TS and Chatham SS and had an expected in-service date of 2028. That scope was based on early indications from the IESO during a then ongoing bulk planning process for the region and was subsequently revised in the IESO's final bulk planning report, *Need for Bulk System Reinforcements West of London* issued in September 2021, which included recommendations that informed the requirements set out in OICs 875/2022 and 876/2022.

This investment is non-discretionary. As explained in ISD T-SS-11, Hydro One considers projects recommended by the IESO through bulk system planning studies to be non-discretionary in nature in either of the following circumstances: (i) where through the IESO's Bulk System Planning Process Hydro One is identified, expressly or implicitly, as the relevant transmitter to undertake a recommended transmission solution, or (ii) where following the IESO's Bulk System Planning Process a transmission solution is designated by OIC as a priority transmission project and Hydro One, expressly or implicitly, is identified as the relevant transmitter to undertake the priority transmission project, including where Hydro One is required by its transmission licence to develop the project.

Furthermore, as a licenced transmitter and pursuant to its responsibilities under the Transmission System Code, Hydro One is obligated to provide facilities that are necessary to maintain the reliability and integrity of its transmission system and that reinforce or expand its transmission system as required to meet load growth.

1.0 INVESTMENT NEED

This investment is required to reinforce the transmission system supplying the Windsor – Essex region and ensure sufficient bulk transfer capability east of Chatham to supply the forecasted load in Windsor-Essex over the mid- to long-term. The west of London area encompasses a 230 kV and 115 kV high voltage network stretching from the western edge of the City of London, to Lambton-Sarnia in the northwest, and the City of Windsor in the west. This system interconnects large generators in the Lambton-Sarnia and Windsor areas with existing load centres and encompasses the growing Kingsville-Leamington and Chatham-Kent areas. It provides four interconnection points with Michigan's power system via Windsor and Lambton-Sarnia. The area also encompasses a connection to the 500 kV system at Longwood TS within the Municipality of Strathroy Caradoc, providing a strong path for supply to and from the region and the rest of the province.

There are two main pockets of load growth and economic development in the area west of London: Kingsville-Leamington, and in the community of Dresden, located within the Municipality of Chatham-Kent. This growth is driven by the expansion of the agricultural sector, mainly in vegetable greenhouses, as well as in part, cannabis, specifically through the intensification of existing greenhouses switching to lit indoor facilities, expansion of greenhouse facilities, and supplemental load to support the agricultural sector.

In 2019, the IESO published a bulk transmission study for the area, *Need for Bulk Transmission Reinforcement in the Windsor-Essex Region,* [1] which recommended transmission upgrades to supply this increased electricity demand in the region. The upgrades recommended in the 2019 study address bulk transmission system limitations west of Chatham between Chatham Switching Station (SS) and the Kingsville-Leamington area. At that time, transmission system constraints east of Chatham were also identified, but additional assessments were required before further bulk recommendations could be made.

[1] Need for Bulk Transmission Reinforcement in the Windsor-Essex Region, June 13, 2019, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Need-for-Bulk-Transmission-Reinforcement-in-Windsor-Essex-Region-June2019

At the time of Hydro One's prior transmission rate application (EB-2021-0110), the bulk planning process for the region was still underway. Hydro One received formal direction from the IESO in a hand-off letter dated March 26, 2021 to proceed with the development of a new double-circuit 230 kV transmission line from Lambton TS to Chatham SS. The associated station expansions to facilitate connection of the St. Clair Transmission Line (i.e., Stage 1 station work) are expected to be placed in service in 2027. Based on communications with the IESO during the bulk planning process, Hydro One included preliminary Stage 2 station work in its 2023-2027 capital expenditure plan, which contemplated the need to connect a new 230 kV double-circuit transmission line to Longwood TS and Chatham TS.

In September 2021, the IESO published the *Need for Bulk System Reinforcements West of London* (the West of London Bulk Planning Report),[2] which recommended an alternate scope for Stage 2 station work, consisting of connecting a new single-circuit 500 kV transmission line to Longwood TS and Lakeshore TS, with an expected in-service date of 2030. The Stage 2 station work enables the supply of the forecasted electricity demand for the Windsor-Essex and Chatham-Kent regions, improves the transfer capability into the regions, and improves the capability of the transmission system to deliver the output of generation resources in the Lambton-Sarnia area.

On March 31, 2022, the Minister issued OICs 875/2022 and 876/2022, designating both Stages 1 and 2 as priority transmission projects in accordance with s. 96.1 of the *Ontario Energy Board Act, 1998,* and directing the OEB to amend Hydro One's Transmission Licence to include requirements for Hydro One to proceed with development and approvals for the Stage 1 and 2 projects (along with the associated lines work which will be owned by an ATP) in accordance with the scope and timing recommended by the IESO. Hydro One's Transmission Licence was so amended, effective April 6, 2022 (EB-2022-0142).

[2] Need for Bulk System Reinforcements West of London, September, 2021, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/southwest-ontario/WOL_Bulk_Report_Final_20210923.pdf

The investment is driven by bulk planning needs, priority designation by the Minister and compliance with Hydro One's transmission licence. The following regional planning reports also identify the investment as one of the major projects currently under development to address emerging electricity needs in the region:

- Windsor-Essex Integrated Regional Resource Plan (Apr 3, 2025); and
- Windsor-Essex Regional Infrastructure Plan (Oct 20, 2025).

Hydro One is obligated to provide facilities that are required to maintain the reliability and integrity of its transmission system and to reinforce or expand its transmission system as necessary to meet expected load growth in accordance with its Transmission Licence and the Transmission System Code. Not proceeding with this investment would result in Hydro One not meeting these obligations and not addressing the need for transmission capacity in the west of London area.

2.0 INVESTMENT DESCRIPTION

The proposed investment is to construct the necessary station expansions and upgrades at the terminal stations, Longwood TS and Lakeshore TS. These investments are necessary to facilitate the connection of the new single-circuit 500 kV transmission line, which will increase the transfer capability of the bulk transmission system east of Chatham, and allow the IESO to more effectively dispatch generation resources within the system to meet demand in the Lambton-Sarnia area for intra-zonal and provincial supply. The planned in-service date for the Stage 2 station work is Q3 2030.

The scope of the Stage 2 station work is consistent with the scope in, or as more particularly described in, the Section 92 application (EB-2026-0128), and is as follows:

- Station expansion at terminal stations, Longwood TS and Lakeshore TS, including the installation of new high voltage breakers, disconnect switches, and bus work;
- Installation of new protection, control, and telecommunications systems for the new single-circuit 500 kV transmission line at Longwood TS and Lakeshore TS, including a new relay building at Lakeshore TS;
- Installation of new autotransformers and associated equipment at Lakeshore TS;

- Construction of a new 500 kV switchyard, including two new buildings for maintenance and station service automatic transfer scheme at Lakeshore TS;
- Connection of new circuits into the respective terminal stations; and
- Upgrade to grounding systems at six remote stations to meet the increased fault levels resulting from the addition of the 500 kV transmission line.

The scope and timing for the development of the Stage 2 station work accords with the recommendations of the IESO, pursuant to Hydro One's Transmission Licence, and as set out in a letter from the IESO to Hydro One dated, August 14, 2025.

The new 500 kV transmission line is expected to be owned by and included in the rate base of an ATP. These assets will not form part of Hydro One's rate base and, as such, the associated capital expenditures do not form part of the 2028-2032 forecast.

A map showing the project location is provided in Figure 1 below.

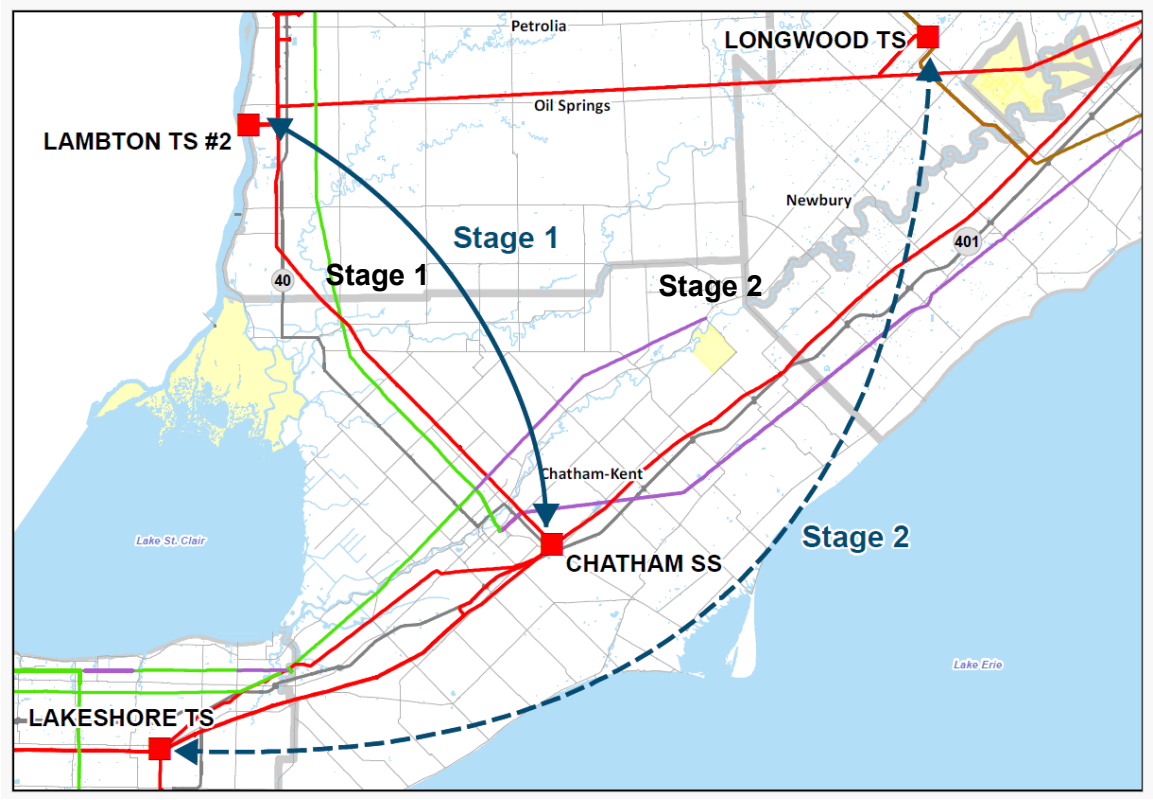

Figure 1:Map Showing Location of the New Facilities

In Q1 2026, Hydro One filed the Final Environmental Study Report and Statement of Completion for Stage 2 with the Ministry of the Environment, Conservation and Parks, as required under the *Environmental Assessment Act* (Ontario).

In Q2 2026, Hydro One applied for leave to construct approval under Section 92 of the *Ontario Energy Board Act, 1998* for the Stage 2 scope of work, and including the line to be owned by the ATP. For additional details, please refer to the Section 92 application (EB-2026-0128).

The System Impact Assessment and Customer Impact Assessment for both Stage 1 and Stage 2 have been completed by the IESO and Hydro One, respectively, and confirm that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

3.0 OUTCOMES

This investment will enable the required increase in bulk transfer capability east of Chatham to supply the forecast load in the Windsor-Essex region and surrounding Chatham area in the mid- to long-term, and thereby allow the IESO to more effectively dispatch generation resources within the system to meet demand in the Lambton-Sarnia area for intra-zonal and provincial supply.

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcomes Summary

Customer Focus	• Ensure adequate supply capacity to support future load growth.
Operational Effectiveness	• Increase supply reliability in the Windsor-Essex region • Permit resources and bulk facilities in the region to operate efficiently.
Public Policy Responsiveness	• This investment is required pursuant to the OICs as reflected in Hydro One's Transmission Licence. • Comply with Hydro One's obligation under its Transmission Licence and the TSC to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth.

4.0 EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recovered from the network rate pool as these 500 kV facilities are network assets and no capital contributions are required from customers.

Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 rate period. For greater certainty, the costs shown in Table 2 are exclusive to the Stage 2 scope of work.

Table 2 - Hydro One - Investment Expenditures[3]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	55.4	42.8	28.9	0.5	0.0	127.7
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	**55.4**	**42.8**	**28.9**	**0.5**	**0.0**	**127.7**

As proposed in Exhibit G-01-03 Section 3.1, the Externally Driven Transmission Projects Variance Account will record the revenue requirement impact of variances between the in-service additions embedded in Hydro One's approved revenue requirement relating to this investment and the actual in-service additions for this investment over the 2028-2032 period.

Table 3 below includes the prior project total, current project total, as well as the maturity of the project at the time of filing, where Execution (E) reflects fully approved project work and Planning and Definition (P) reflects non-execution work, regardless of level of upfront development.

Table 3 - Hydro One – Net Investment Expenditures

Investment Name	Type	Prior Proj. Total[4]	Prior In-Service Year	Type	Proj. Total	In-Service Year
Stage 1 - Station Work – Lambton TS to Chatham SS (St. Clair Transmission Line)	P	81.2	2028	E	88.2	2027
Stage 2 - Station Work (Longwood to Lakeshore Transmission Line)	P	55.9	2029	E	285.0	2030

Hydro One expects the Stage 1 project total to be $7M higher than the prior project total. This increase is primarily due to higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF 1.8. Neither the inflation assumptions in

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period.

Stage 1 is expected to be in-serviced ahead of the required date from the IESO's 2021 West of London Bulk Planning Report. The forecast improvement in project delivery timelines is a product of Hydro One's ongoing Reconciliation efforts with Indigenous communities, early and meaningful engagement with the local community that allowed the company to integrate local needs into project planning, as well as Provincial and municipal organizations' prioritization of the project.

Hydro One expects to place the Stage 2 station work in service in 2030 with a net project total of $285M. Hydro One expects to complete planning and development work and begin execution prior to 2028, incurring approximately $157.3M of the $285M project total in the 2023-2027 period. The remaining $127.7M of the project total will be incurred during the 2028-2032 period, as shown in Table 2 above. Hydro One forecasts the Stage 2 project total to be $229.1M higher than the prior project total of $55.9M due to the following:

- The prior project total was premised on preliminary indications from the IESO communicated to Hydro One during an ongoing bulk planning process. Those preliminary indications contemplated a 230 kV transmission line connection between Longwood TS and Chatham SS rather than the current scope of Stage 2, which involves the connection of a 500 kV transmission line between Longwood TS and Lakeshore TS. This is a change in termination point and voltage, and also an increase in terminal station modification work required at Lakeshore TS to include the establishment of a new 500 kV switchyard, as the station currently has no 500 kV facilities, and the installation of two 500/230 kV autotransformers to connect the existing 230 kV and new 500 kV switchyards.
- As a result of the construction of the 500 kV transmission line, the ground fault levels at six remote stations are expected to increase substantially and thus the existing grounding installations at these stations would no longer meet requirements. In order to remain in compliance, minor grounding work, including expansion of the grounding grid and installation of ground rods, is required in addition to the terminal station work at Longwood TS and Lakeshore TS.

- The prior project total does not reflect the higher and sustained inflationary pressures experienced by Hydro One described above.

5.0 ALTERNATIVES

No alternatives were considered due to the priority transmission project designation by the Minister and the transmission licence obligation for Hydro One to complete the Stage 2 stations work in accordance with scope and timing recommended by the IESO, which is reflected in a letter from the IESO to Hydro One dated August 14, 2025. This non-discretionary investment is needed to ensure supply reliability for the customers in the Windsor-Essex region and support future load growth.

6.0 EXECUTION RISK AND MITIGATION

The risks with respect to the execution of this investment as planned would include potential delays in securing the required approvals, permits, authorizations and lands rights required to construct the project. These risks have been mitigated by initiating the approval, permit, and authorization processes in a timely manner and by initiating engagement with landowners early in the development of the project.

Normal project risks that may also affect the timely completion of the investment include the availability of outages required for the work to be executed. This risk will be mitigated by setting a schedule that aligns with outage availability.

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T-SS-10	**GREENSTONE TRANSMISSION LINE PROJECT - STATION**
Primary Trigger:	Interconnection
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	20.0	20.0	16.0	19.0	20.0	95.0

Summary:

This non-discretionary investment will complete essential station work to enable the development of the Greenstone Transmission Line, a new 230 kV circuit in Northern Ontario, designated as a priority project by the Government of Ontario.

The need for this project has been established pursuant to Order in Council 1664/2025 (Greenstone OIC), issued by the Minister of Energy and Mines (the Minister), dated December 11, 2025, and is accordingly designated as a priority project under s. 96.1(1) of the *Ontario Energy Board Act, 1998* (OEB Act). Hydro One's Transmission Licence has been amended by the OEB under direction from the Minister, effective January 29, 2026 (EB-2026-0080), adding the requirement for Hydro One to proceed with the Greenstone Transmission Line development.

The expenditures in this investment will fund the construction of three new stations which are essential to enable the development of the Greenstone Transmission Line. The new 230 kV transmission line is expected to be owned by and included in the rate base of a newly licensed Affiliate Transmission Partnership (ATP). The line facility assets will not form part of Hydro One's rate base and, as such, the associated capital expenditures have been excluded from the 2028-2032 planning period.

This investment is non-discretionary. The station work is required to enable the Greenstone Transmission Line, a priority project that Hydro One is required to develop under its Transmission Licence.

1.0 OVERVIEW

This non-discretionary investment will complete essential station work to enable the development of the Greenstone Transmission Line, pursuant to the Greenstone OIC and in accordance with Hydro One's Transmission Licence, as amended by the OEB under the Minister's direction.

As shown in Figure 1 below, the new transmission line will span approximately 220 km, running from the East-West Tie Interface near Nipigon Bay, heading north toward Aroland First Nation. The routing of the transmission line shown in Figure 1 is purely illustrative. Routing will be determined through the Environmental Assessment process.

The following three new stations (see Figure 1) will be constructed under this investment:

- A new switching station (SS) connected to an existing 230 kV circuit, M24L, between Marathon TS and Lakehead TS, as the main connection to the grid;
- A new transformer station (TS) at or near the town of Geraldton, where a 230 kV / 115 kV auto-transformer will be installed to connect to existing 115 kV circuit A4L; and
- A new station near Aroland First Nation, as the current terminal point for a line terminal.

The above stations are expected to be placed in-service in 2032.

The planned scope of the Greenstone Transmission Line, including the stations work set out in this investment, is consistent with the IESO's recommendations as documented in its letter to Hydro One, dated February 27, 2026.

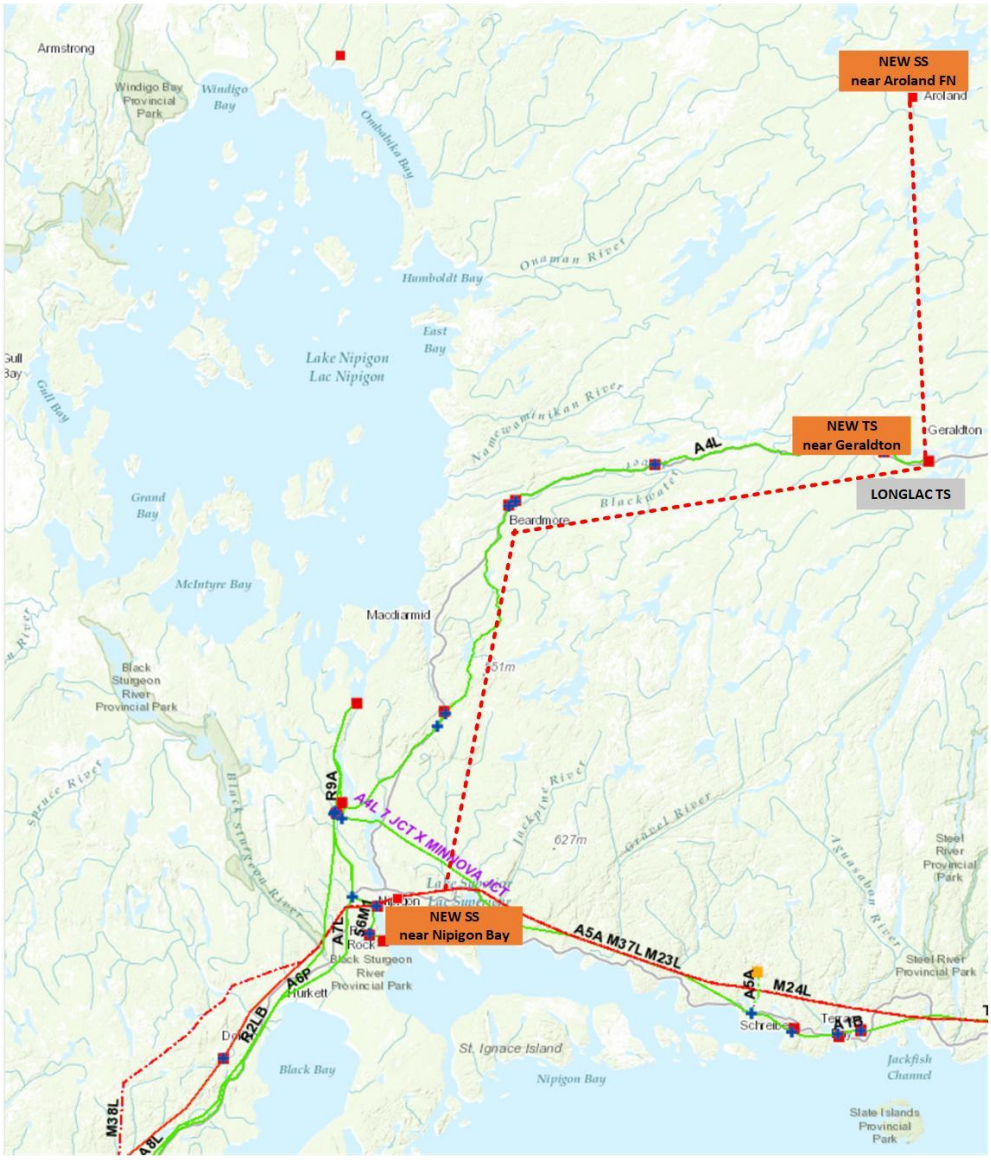

Figure 1: High-level project overview [red dotted line represents new line]

2.0 INVESTMENT NEED

The need for this project has been established pursuant to the Greenstone OIC, issued by the Minister, dated December 11, 2025, which designated the project as a priority transmission project under s. 96.1(1) of the OEB Act. Moreover, Hydro One's Transmission Licence has been amended by the OEB under direction from the Minister to require Hydro One to proceed with the Greenstone Transmission Line development.

Hydro One initiated the IESO System Impact Assessment (SIA) application in Q2 2026 and preliminary results are expected in Q1 2027 to confirm this project has no adverse reliability impact on the IESO-controlled grid. The Environmental Assessment and First Nation engagement are ongoing in support of the Section 92 application.

3.0 INVESTMENT DESCRIPTION

This investment covers the scope of station work outlined below, as required under the Greenstone OIC and Hydro One's Transmission Licence. The lines portion of the work is outside the scope of this investment and is expected to be owned by and included in the rate base of a newly licensed ATP. This lines asset will not form part of Hydro One's rate base and, as such, the associated capital expenditures have been excluded from the 2028-2032 planning period.

The planned scope of the Greenstone Transmission Line, including the stations work set out in this investment, is consistent with the scope documented in the above noted IESO recommendation letter, as set out in the following:

> The IESO recommends Hydro One develop the Greenstone Transmission Project as a single-circuit 230 kV transmission line from the existing East-West Tie near Nipigon Bay to Aroland via Longlac TS, with the ability to accommodate a future second circuit. This ensures that the North–South Corridor Option assessed in [the Northern Ontario Connection Study (NOCS)] remains available should further work identified through NOCS proceed in the future. In the NOCS, the North–South Corridor Option is evaluated as a double-circuit 230 kV transmission line connecting to the existing East–West Tie near Nipigon Bay.
>
> The IESO recommends that Hydro One install a new 230/115 kV auto-transformer(s) at or near Longlac TS to interface the new 230 kV line with the existing A4L corridor. The Greenstone Transmission Line includes connecting the new 230 kV transmission line with the existing 115 kV system near Longlac Transformer Station.
>
> The IESO recommends that Hydro One develop the Greenstone Transmission Project to maintain the optionality for future northward phases of the North–South Corridor Option should further work identified through the NOCS proceed in the future. The NOCS contemplates that the initial one third of the North-South Corridor Option could be continued

northward beyond Longlac toward prospective community and mining connections.[1]

The locations and other aspects of the necessary stations assets will be finalized based on factors including, but not limited to, the environment assessment outcome, route selection, real estate, community relationship, and engineering feasibility. These factors will be addressed during project development, which began with early assessment activities in 2026.

The essential design features of the stations are as follows:

Station 1 - New 230 kV SS near Nipigon Bay Configurations

This station will initially be configured as a 230 kV 3-breaker ring bus switching station to intersect with an existing 230 kV East-West Tie circuit (M24L) between Marathon TS and Lakehead TS near Nipigon Bay. This configuration will provide the first 230 kV line termination for the interconnection of Greenstone Transmission line. The ultimate design will be expandable to accommodate additional circuits.

Station 2 - New 230/115 kV TS Connecting to 115 kV circuit A4L

This transformer station includes a 230/115 kV autotransformer, with one 230 kV breaker and 3-breaker ring bus to connect to the 115 kV A4L circuit.

Station 3 - New 230 kV Station Near Aroland First Nation

During the 2028-2032 rate period, station work will involve the installation of 230 kV reactors for voltage control.

This investment also includes expenditures for a subsequent phase to preserve expansion optionality of Station 3 such that future station expansion can be accommodated for future load and generation connections, enabling connecting communities, mining development and industrial development that could include additional generation resources, in alignment with IESO recommendations.

[1] IESO Recommendation Letter, EB-2026-0080, February 27, 2026, p. 2. The NOCS, referenced by the IESO Recommendation Letter, is an IESO-led study requested by the Minister.

The exact configuration of the stations will reflect the IESO's SIA assessments as well as recommendations and requirements from the ongoing NOCS, an IESO-led study requested by the Minister. The IESO has been evaluating multiple long-term transmission options to connect off-grid First Nation communities, improve reliability, and enable mining development and potential supply resources in Northern Ontario.

4.0 OUTCOMES

This investment will enable the reinforcement of the transmission system supplying the Greenstone region and enable better reliability and capacity for regional economic growth. This will result in reliability improvements for First Nation communities that are already grid-connected and provide opportunities to connect to the grid for remote First Nation communities that currently rely on diesel generators for electricity. Additionally, this investment will support critical minerals mining development and enable the development of potential new hydro and renewable generation resources.

The new 230 kV circuit will terminate near Aroland First Nation and will provide broader network benefits, including enabling new generation and provisions for future network transmission circuits to connect remote communities, and provide a location to site reactive support devices that control voltage.

4.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcome Summary

Customer Focus	• **First Nation Communities -** There are seven First Nation communities currently experiencing significant reliability concerns and barriers to growth as they acquire new housing, transition from carbon heating to electrical solutions, and advance economic development initiatives in their communities. • **Critical Mineral Projects –** More transmission capacity and reliability enabled by the stations investment will enable critical mineral projects which is a priority for Provincial and Federal Governments. The region is home to significant critical mineral deposits including lithium, nickel, copper, zinc, etc. and this transmission investment would support their advancement and local industrial growth.
Operational Effectiveness	• This transmission investment enables enhancement of the reliability and capacity of the region. It modifies the supply to the local area from a single radial 115 kV supply (A4L) to a 230 kV network loop that provides redundancy for increased reliability in the region which has historically been an issue.
Public Policy Responsiveness	• This investment is required pursuant to the Greenstone OIC and Hydro One's Transmission Licence.

5.0 EXPENDITURE PLAN

Table 2 below summarizes Hydro One's forecast capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One - Investment Expenditures[2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	20.0	20.0	16.0	19.0	20.0	95.0
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	**20.0**	**20.0**	**16.0**	**19.0**	**20.0**	**95.0**

As proposed in Exhibit G-01-03 Section 3.1, the Externally Driven Transmission Projects Variance Account will record the revenue requirement impact of variances between the in-service additions embedded in Hydro One's approved revenue requirement relating

[2] Figures presented in the tables may not sum to the totals shown due to rounding.

to this investment and the actual in-service additions for this investment over the 2028-2032 period.

Stations 1, 2, and 3 discussed above are expected to be placed in-service in 2032 at a forecast project total of $117.0M. Prior to 2028, Hydro One will have undertaken development work, including commencement of the Environmental Assessment, technical studies for the development of estimates, project schedule definition, and First Nation and community engagement activities. Hydro One expects to incur $48.0M before 2028 for these activities. The remaining $69.0M of the $117.0M forecast project total is included in the 2028–2032 expenditure forecast.

This investment also includes expenditures for a subsequent phase to preserve expansion optionality of Station 3, amounting to expenditures of $26.0M during the 2028-2032 period, which Hydro One anticipates to in-service in a future rate period.

6.0 ALTERNATIVES

This investment is non-discretionary. Hydro One is obligated to undertake the stations work which is essential to enable the Greenstone Transmission Line pursuant to its Transmission Licence. There are no alternatives to consider since the project is designated and directed by the Minister and the parameters have been set by the IESO.

This investment enables the Greenstone Transmission Line, which reinforces the existing transmission system, enabling higher reliability, local area growth, and new load and generation connections.

7.0 EXECUTION RISK AND MITIGATION

A risk with respect to the execution of this investment as planned includes potential delays in securing community support over land use. This risk will be mitigated by initiating early engagement with stakeholders to ensure Section 35 duty to consult requirements are met and by co-developing a community engagement plan offering community benefit frameworks for employment pathways and contracting opportunities. Indigenous knowledge integration in environmental baseline studies will be considered as part of a collaborative Indigenous and Local Participation Strategy effort. The team will be

conducting listening sessions on preliminary issues before formal regulatory processes begin as well as training programs to build local readiness. The Environmental Assessment process has been initiated in a timely manner to mitigate risk associated with securing environmental approval.

Other normal project risks that may affect the timely completion of the investment include the availability of outages required for the work to be executed. These risks will be mitigated by setting a schedule that aligns with outage availability.

1 This page has been left blank intentionally.

T-SS-11	BULK PLANNING
Primary Trigger:	Bulk Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2027	2028	2029	2030	2031	2032	Total
Hydro One	-	762.4	1,042.4	1,097.0	1,291.6	939.4	5,132.8
HOSSM	18.3	29.4	9.2	0.3	0.0	0.0	57.2

Summary:

This non-discretionary investment is required to enable Hydro One to undertake a large portfolio of bulk system projects comprised of modifications to Hydro One owned network assets, and construction of new network assets, where Hydro One has been identified by the Independent Electricity System Operator (IESO) through the Bulk System Planning Process and related studies, implicitly or explicitly, as the recommended transmitter to undertake the modifications or new construction.

The portfolio of projects included in this investment for the 2028-2032 period consists of 26 material investments arising from the IESO's recommendations across six bulk planning study areas, and which identify the need for investment during the 2028-2032 period. These study areas include the Gatineau Corridor, the Northeast Bulk System, Northern Ontario, North of Sudbury, South and Central Ontario, and Eastern Ontario.

In addition to having been identified through IESO bulk system planning recommendations, Orders in Council (OIC) have been issued by the Government of Ontario declaring seven of the investments to be priority transmission projects pursuant to section 96.1 of the *Ontario Energy Board Act, 1998*. Under Ministerial Directives, Hydro One's Transmission Licence has been amended to require Hydro One to develop and seek approvals necessary for carrying out these projects.

Projects vary from station expansions to new transmission lines, to reactive support installations, and reconductoring existing circuits. Many projects are linked to increasing

transfer capability, enabling load growth, generation connections, and maintaining reliability at the provincial bulk system level.

Hydro One considers bulk system projects non-discretionary when the IESO identifies it as the transmitter responsible for implementing recommended solutions, either expressly or implicitly, or the IESO's recommended solution relates directly to Hydro One's existing transmission facilities, or when projects are designated priority transmission projects by the OICs where Hydro One is required to undertake the project as a result of a Transmission Licence condition made pursuant to a Ministerial Directive.

HOSSM is also obligated to perform work arising from IESO bulk planning recommendations, OICs and Ministerial Directives affecting its transmission system. One such investment is the Third Line TS station work investment which enables the North Shore Link. All information related to HOSSM is set out in Appendix C.

1.0 OVERVIEW

This non-discretionary investment is required to enable Hydro One to undertake a large portfolio of bulk system projects comprised of modifications to Hydro One owned network assets, and construction of new network assets, where the project has been identified as being needed by the IESO through the Bulk System Planning Process[1] and related studies, and Hydro One has been identified, expressly or implicitly, as the recommended transmitter to undertake the modifications or new construction. The portfolio of projects included in this ISD therefore consists of a mix of investments in network assets, the need for which has been identified through IESO Bulk System Planning studies, where such studies either have final recommendations or draft recommendations published, and which identify the need for investment during the 2028-2032 period.

For context, it is important to understand that the IESO is responsible under the *Electricity Act, 1998* for performing independent planning for electricity generation, demand management, conservation and transmission in Ontario. The IESO's mandate for planning is to ensure that Ontario has, and will continue to have, an adequate and reliable supply of resources and transmission to meet Ontario's needs. Planning has been carried out in Ontario for decades, previously by the Ontario Power Authority and before that by Ontario Hydro. These planning activities have historically delivered planning outcomes such as the Integrated Power System Plans, Ontario Planning Outlooks, Annual Planning Outlooks, and Bulk System Plans.

Generally, the foundation of IESO planning consists of Bulk System Planning and Regional Planning (see ISD T-SS-12 and SPF Section 1.2), which are distinct but interrelated activities. Whereas Regional Planning is performed by lead-transmitters with IESO involvement in each of 21 regions through a process that has been defined by the OEB, Bulk System Planning is performed by the IESO in various bulk planning regions, and for the province as a whole, to address system issues that are provincial in nature, such as provincial generation capacity and transmission system solutions to enable the reliable and economic transmission of power across Ontario. While historically Bulk System Planning was undertaken through informal internal IESO processes, since 2022

[1] See https://www.ieso.ca/Get-Involved/Bulk-Planning/Overview.

the IESO has followed a more formal Bulk System Planning Process that is more consistent, structured and transparent.

The IESO's Bulk System Planning Process identifies and addresses emerging needs on Ontario's high-voltage grid (the province's backbone of 500 kV transmission facilities, as well as regional 230 kV transmission facilities) over the medium- and long-term. Bulk planning evaluates whether the transmission system can, at an inter-regional level, reliably deliver electricity from supply resources to load centres and maintain overall system reliability across regions in the province, using a structured approach that involves four distinct phases carried out by the IESO:

- Demand Forecast Phase - Assesses how much electricity demand is forecasted to be needed over the planning timeframe;
- Needs Phase - Considers whether the electricity system can meet customer demand through a combination of local generation and transmission capacity;
- Evaluation of Options Phase - Reviews potential solutions that can meet the future needs of the bulk planning region; and
- Recommendations Phase - Identifies recommended actions from the assessment of options, which will ensure reliable and adequate supply over the long-term.

Where IESO's bulk planning recommendations are for non-wires alternatives, those recommendations feed into various IESO processes such as electricity Demand Side Management (eDSM), demand response, distributed generation, and longer-term capacity procurement plans. Where IESO's bulk planning recommendations are for wire solutions, those recommendations feed into the investment planning processes of the relevant transmitter(s) to support the need, scope and timing for the recommended wire solutions. Where a particular recommended transmission solution is urgently or strategically needed, the Government of Ontario may provide additional support for the recommended solution through mechanisms such as OICs and Ministerial Directives, which can designate solutions as priority transmission projects and require the OEB to make it a condition of licence for a particular transmitter to develop and seek approvals for a given project.

Based on the foregoing, Hydro One considers a bulk system project to be non-discretionary in nature in either of the following circumstances: (i) where through the IESO's Bulk System Planning Process Hydro One is identified, expressly or implicitly, as the relevant transmitter to undertake a recommended transmission solution, or (ii) where following the IESO's Bulk System Planning Process a transmission solution is designated by Order in Council as a priority transmission project and Hydro One, expressly or implicitly, is identified as the relevant transmitter to undertake the priority transmission project, including where Hydro One is required by its transmission licence to develop the project.

The IESO and Hydro One have complementary responsibilities and work collaboratively throughout the Bulk System Planning Process. The IESO is the bulk system planner and leads the process that results in the IESO making recommendations for transmission expansion or reinforcement solutions that are required to address identified system reliability or operability needs in accordance with North American Electric Reliability Corporation (NERC) standards, Northeast Power Coordinating Council (NPCC) criteria and IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC). Hydro One participates throughout the IESO-led planning process by providing input data such as network data and asset information, supporting or performing technical studies, providing analysis on project constructability and timelines, and developing implementable project scopes that assist in progressing a recommended solution into an executable project. Hydro One's role also includes advising on practical deliverability considerations, such as station configuration and optimization, protection and control design, outage feasibility, regulatory permitting, schedule risk, land requirements, as well as stakeholder and Indigenous engagement.

Hydro One's participation in the Bulk System Planning Process and its responsibilities for implementing recommended solutions arise from its obligations as a licenced transmitter to design, construct, operate and maintain its transmission system in accordance with the OEB's Transmission System Code,[2] and to comply with the Reliability Standards

[2] See for example s. 5.1.2 of the TSC, which requires a transmitter to operate and maintain its transmission facilities in compliance with the TSC, its licence, its operating agreement with the IESO, the Market Rules, all connection agreements, good utility practice, the standards of all applicable reliability organizations (i.e. NERC, NPCC, IESO) and any applicable law.

Framework[3] including mandatory NERC standards, NPCC and ORTAC criteria, as enforced in Ontario through the IESO-administered Ontario Reliability Compliance Program.[4]

Accordingly, when the IESO identifies a bulk system need and recommends reinforcements within a targeted in-service timeline, if the recommended work involves modifications to Hydro One's existing Network facilities or the construction of new facilities directly related to Hydro One's existing Network facilities, or where Hydro One has been recommended (and/or designated) as the entity to develop, seek approvals for and/or to build new Network assets, then it is incumbent upon Hydro One to implement the recommended solution by incorporating it into its investment plans, undertaking the relevant development and scoping work, applying for and securing required approvals, procuring the necessary land rights and equipment, and putting into service the recommended facilities in a manner that delivers sustained compliance with the reliability standards and criteria underlying the established need. This includes ensuring that final designs, protection and control schemes, and resulting operating configurations remain compliant at commissioning and throughout the asset life cycle.

For the reasons set out above, this investment in a portfolio of IESO-identified bulk system projects is non-discretionary. By virtue of the fact that Hydro One owns and operates more than 90% of Ontario's transmission system, it is obligated to implement most transmission solutions that the IESO recommends through the bulk system planning process. These recommendations are driven by the need to maintain the reliability and integrity of Ontario's bulk electricity transmission system in accordance with NERC, NPCC and IESO reliability standards and criteria. These recommended solutions necessitate modifications to Hydro One's existing transmission system, or the construction of new transmission facilities, which Hydro One must implement to ensure compliance with reliability standards and criteria, as well as to meet load growth, in accordance with its Transmission Licence and the TSC. Not proceeding with this portfolio of investments, or specific investments within the portfolio, within the IESO's specified timelines is not an alternative as it would

[3] See https://www.ieso.ca/Sector-Participants/System-Reliability/Reliability-Standards-Framework
[4] See https://www.ieso.ca/Sector-Participants/System-Reliability/Ontario-Reliability-Compliance-Program

result in Hydro One failing to meet its obligations as a licenced Ontario transmitter, Ontario's bulk system failing to meet NERC, NPCC and IESO reliability standards and criteria, and/or inadequate transmission capacity to support anticipated generation growth and load growth, as well as related economic growth.

2.0 INVESTMENT NEED

This investment is driven by recommendations that the IESO has made in seven bulk system planning studies across six study areas since 2022 for a portfolio of projects consisting of new or modified transmission facilities, in order to prepare Ontario's bulk electric system to meet forecasted future needs and maintain compliance with reliability standards and criteria. While the specific drivers for individual projects within the portfolio vary, the common driver for these bulk level transmission projects is the need to increase power transfer capability along different parts of Ontario's bulk electric system to enable future additional load or generation resources at a cross-regional level.

Bulk system planning studies since 2022 have resulted in specific recommendations for transmission solutions for the following study areas: Northern Ontario[5], South and Central Ontario[6], Eastern Ontario[7], and North of Sudbury[8]. Bulk planning initiatives have also been completed for the Gatineau Corridor[9] and the Northeast Bulk System.[10] Additional IESO-led bulk system planning commenced for the Niagara region in Q2 of 2026, with early actions and draft recommendations slated for Q1 and Q2 of 2027, respectively, and a final report and recommendations in Q3 of 2027.[11] Where an ongoing initiative is in its early stages, such as for the Niagara region, Hydro One has not included any related projects

[5] See https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Northern-Ontario-Bulk-Planning.
[6] See https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/South-and-Central-Bulk-Planning.
[7] See https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Eastern-Ontario-Bulk-Planning.
[8] See https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/North-of-Sudbury-Bulk-Planning.
[9] See https://www.ieso.ca/Get-Involved/Regional-Planning/East-Ontario/bulk-planning.
[10] See https://www.ieso.ca/Get-Involved/Regional-Planning/Northeast-Ontario/Bulk-Planning.
[11] See https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Niagara-Bulk-Planning.

in the portfolio. As bulk plans continue to mature, Hydro One will update this Application to reflect any material changes to forecast capital expenditures, if required.

Table 1 below summarizes the seven IESO-led bulk system planning studies across six study areas which have resulted in implementation-ready recommendations for transmission reinforcements that require investment by Hydro One during the 2028-2032 period. For the Northern Region, there are two distinct studies. For the South & Central region and the Eastern Ontario region, the recommendations are split out into sub-regions (Modules). Each of the studies are discussed in greater detail following the table.

Table 1 - Summary of IESO Bulk Studies and Recommendations

IESO Region/Study (Year Published)	Hydro One Project	ISD Ref.
Gatineau Corridor: **Gatineau Corridor End of Life (2022)**	• Station expansions and upgrades at Dobbin TS and Clarington TS to accommodate the new 230 kV Durham Kawartha Power Line	T-SS-11.01
Northeast Bulk System: **Need for Northeast Bulk System Reinforcements (2022)**	• Station expansions and upgrades at Mississagi TS and Hanmer TS to accommodate the new 500 kV Northeast Power Line • Station expansions and upgrades at Mississagi TS and Third Line TS, to accommodate the new 230 kV North Shore Link • Station expansions and upgrades at Wawa TS and Porcupine TS to accommodate the new 230 kV Wawa–Timmins Powerline	T-SS-11.02 T-SS-11.03 T-SS-11.04
Northern Ontario: **Bulk System Reactive Requirements in Northern Ontario (2023)**	Reactive support projects including: • Reactors at Lakehead TS • STATCOMs at Mississagi TS and Algoma TS (integrated with North Shore Link, T-SS-11.03) • Reactive support at Mackenzie TS (integrated with Waasigan Project, T-SS-16)	T-SS-11.03 T-SS-11.05
Northern Ontario: **North–South Transmission Reinforcement Plan (2025)**	• Station expansions at Hanmer TS and Essa TS, and series compensation facilities at Nobel SS to accommodate the new 500 kV Sudbury Barrie Transmission Line	T-SS-11.06
North of Sudbury: **North of Sudbury Bulk Plan (2026 Q3)**	• Station expansions and upgrades at Ansonville TS, Dymond TS and Kirkland Lake TS to accommodate a new 230 kV transmission line from Ansonville to Kirkland Lake to Dymond • H9K circuit reconductor	T-SS-11.07 T-SS-11.08 T-SS-11.09 T-SS-11.10 T-SS-11.11

IESO Region/Study (Year Published)	Hydro One Project	ISD Ref.
	• A4/5H corridor reconductor • Station expansions and upgrades to accommodate a new single-circuit 230 kV transmission line from Hunta SS to Pinard TS • Station expansions and upgrades to accommodate a new double-circuit 230 kV transmission line from Porcupine TS to Hunta SS • Station expansions and upgrades to accommodate a new single-circuit 230 kV transmission line from Hunta SS to Kapuskasing TS	
South & Central: **South & Central Ontario Bulk Plan (2026 Q3) – East of Toronto Module**	• Bowmanville SS Expansion for Darlington SMR connection • Cherrywood TS circuit reconfiguration and Bowmanville SS connections to accommodate the new double-circuit 500 kV transmission line from Bowmanville SS to GTA East • Bowmanville SS and Hearn SS upgrades for Toronto Third Supply (HVDC)	T-SS-11.12 T-SS-11.13 T-SS-11.14
South & Central: **South & Central Ontario Bulk Plan (2026 Q3) – GTA North Module**	• Northern York Region Transmission Reinforcement (Kleinburg area) • New 500 kV Line from Claireville TS to Kleinburg TS with station expansion work in Claireville TS and Kleinburg TS • E8V/E9V transmission line reconductoring • New Essa TS autotransformer	T-SS-11.15 T-SS-11.16 T-SS-11.17 T-SS-11.18 T-SS-11.19
South & Central: **South & Central Ontario Bulk Plan (2026 Q3) – GTA West Module**	• Milton 500/230 kV TS development	T-SS-11.20
South & Central: **South & Central Ontario Bulk Plan (2026 Q3) – Southwest Ontario Module**	• New Guelph North 500/230 kV TS • New St. Thomas 500/230 kV TS • Longwood TS 500 kV Expansion to accommodate the new 500 kV line from Longwood to Guelph North TS.	T-SS-11.21 T-SS-11.22 T-SS-11.23
Eastern Ontario: **Eastern Ontario Bulk Plan (2026 Q3) – Belleville Region Module**	•Belleville TS expansion to support the new 230 kV Napanee–Belleville 230 kV transmission reinforcement and reactive compensation facilities	T-SS-11.24
Eastern Ontario: **Eastern Ontario Bulk Plan (2026 Q3) – Ottawa Region Module**	• Station expansions at St. Lawrence TS and Merivale TS to accommodate the new 230 kV circuit between Lawrence TS and Merivale TS • Station expansions at Hawthorne TS for breaker addition • Station expansions at Hawthorne TS for STATCOM installation	T-SS-11.25 T-SS-11.26

The Gatineau Corridor End of Life Study (Completed 2022)

The Gatineau corridor is an existing 300 km long transmission corridor that runs from Durham region to Peterborough and on to Ottawa, as shown in Figure 1 below. It consists of five 230 kV transmission lines that were originally constructed from the late 1920's to early 1930's, with a combined length of 1,300 circuit km.

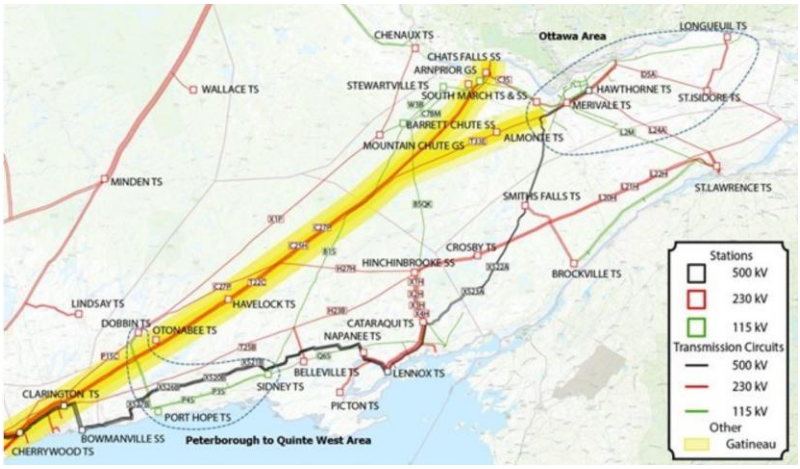

Figure 1: Map of Gatineau Corridor, with area of interest highlighted.

This IESO study examined different transmission options for replacing equipment reaching end of life (EOL) along this corridor, along with forecast load growth and reliability concerns in the area. IESO recommendations that require investments within the rate period are:

1. Build a new double-circuit 230 kV transmission line into Dobbin TS from either Cherrywood TS or Clarington TS, targeted for in-service by 2029.
2. Refurbish approximately 800 circuit km of existing 230 kV circuits on the Gatineau Corridor.
3. Update and expand Remedial Action Schemes (RAS) in the Ottawa and Peterborough areas to improve load meeting capability and reliability, targeted for in-service by 2029.

Recommendations 1 and 3 above have led to the development of the Durham Kawartha Power Line project, with station work at the existing Dobbin TS and Clarington TS required to accommodate the new double-circuit 230 kV transmission line (see Appendix A, T-SS-

11.01). The line portion of the project will be included in a separate Affiliated Transmission Partnership (ATP), and the corresponding expenditures are therefore excluded from this Application. Recommendation 2 will be implemented as a system renewal investment, per Hydro One's Asset Management practices, further described in T-SR-13.

Need for Northeast Bulk System Reinforcements (Completed – 2022)

This IESO bulk planning study assessed the growing electricity demand across Northeastern Ontario (see Figure 2), driven by mining development, industrial expansion, and electrification initiatives. The study identified future transmission constraints and evaluated both transmission and non-wires alternatives to maintain system reliability.

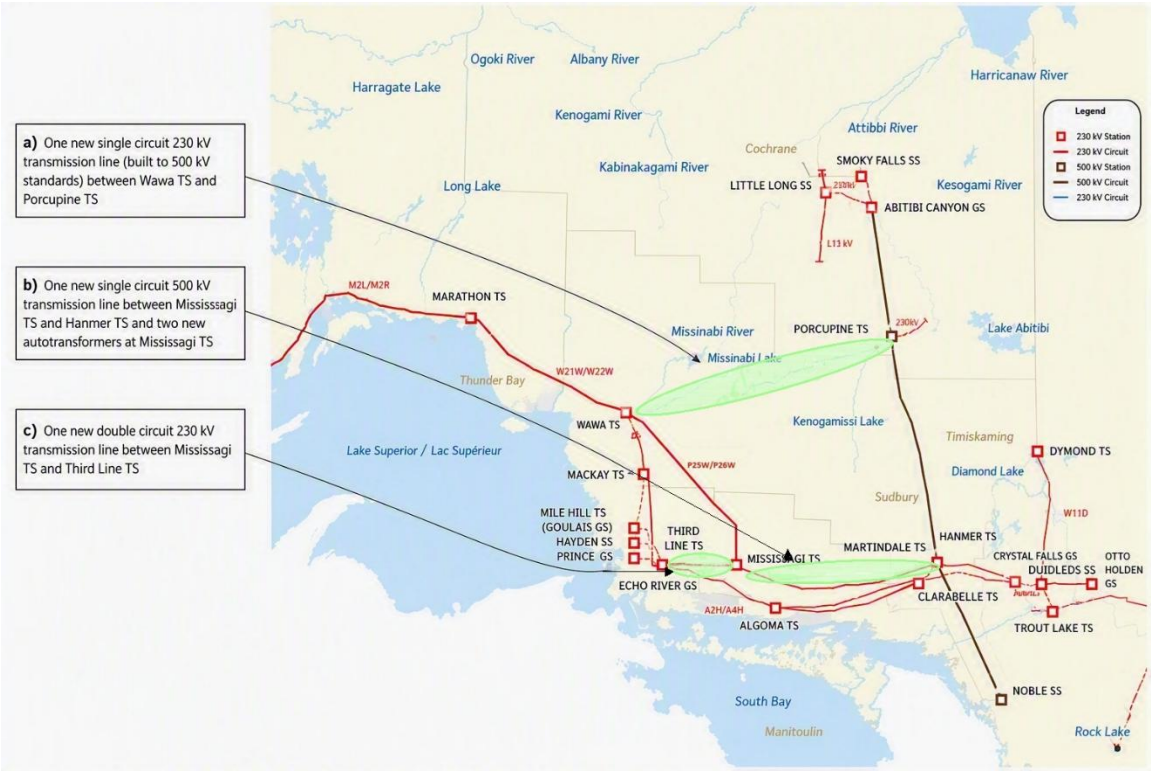

Figure 2: Map of Locations of Northeast Bulk Reinforcements

IESO recommendations that require investments within the rate period are:

4. New single circuit 500 kV transmission line between Mississagi TS and Hanmer TS, and addition of two new 500/230 kV autotransformers at Mississagi TS, with a target in-service year of 2029 to 2030.
5. New double circuit 230 kV transmission line between Mississagi TS and Third Line TS, with a target in-service year of 2029.
6. New single circuit 230 kV transmission line (built to 500 kV standards) between Wawa TS and Porcupine TS, with target in-service year of 2029 to 2030.
7. Associated voltage control equipment and station upgrades, as per IESO study report and recommendations in the Bulk System Reactive Requirements in Northern Ontario report (discussed below) to enable an increase in transfer capability of the above new transmission lines.

The line portion of each individual project discussed in recommendation 4, 5, and 6 above will be included in separate ATP and the corresponding expenditures are therefore excluded from this Application.

Recommendation 4 has led to the Northeast Power Line project to develop a new single circuit 500 kV line from Hanmer TS to Mississagi TS, with necessary station work at both Mississagi TS and Hanmer TS to accommodate the new 500 kV line. Mississagi TS will require a new 500 kV switchyard, complete with two 750MVA, 500/230 kV auto-transformers, and one 120 Mvar, 500 kV in-line reactor as recommended in the Bulk System Reactive Requirements in Northern Ontario report (discussed below) and IESO letter (see below). The existing Hanmer TS 500 kV yard will be expanded to accommodate new 500 kV circuits coming from Mississagi TS (see Appendix A, T-SS-11.02).

Recommendation 5 has led to the North Shore Line project, which involves development of a new double circuit 230 kV transmission line between Mississagi TS and HOSSM's Third Line TS, with a 230 kV switchyard expansion at both Mississagi TS and Third Line TS to accommodate the new 230 kV line (see Appendix A, T-SS-11.03). The project will also include Mississagi and Algoma TS 230 kV switchyard expansions to include 100 Mvar static synchronous compensator (STATCOM) at each station as recommended in the Bulk System Reactive Requirements in Northern Ontario report (discussed below). The station

work at HOSSM's Third Line TS is included in HOSSM's capital expenditures (see TSP Section 2.10 and Appendix C).

Recommendation 6 has led to the Wawa Timmins Powerline project to develop a single circuit 230 kV transmission line (built to 500 kV standards) between Wawa TS and Porcupine TS, with a 230 kV switchyard expansion at both Wawa TS and Porcupine TS to accommodate new circuits (see Appendix A, T-SS-11.04).

Recommendation 7 is further discussed below, under the Bulk System Reactive Requirements in Northern Ontario report.

Bulk System Reactive Requirements in Northern Ontario (Completed – 2023)

This IESO study examined voltage stability and reactive power requirements across Northern Ontario (see Figure 3) in light of increasing electricity demand and major transmission projects such as the Waasigan Transmission Line and the Northeast Bulk System reinforcements. This study complements the IESO's Need for Northeast Bulk System Reinforcements report (completed in 2023). The objective of the study was to identify the reactive compensation needed to maintain acceptable voltage performance and system reliability under future operating conditions. The IESO further supplemented its recommendations with a letter to Hydro One in March 2024, providing directions on implementation and timeline.

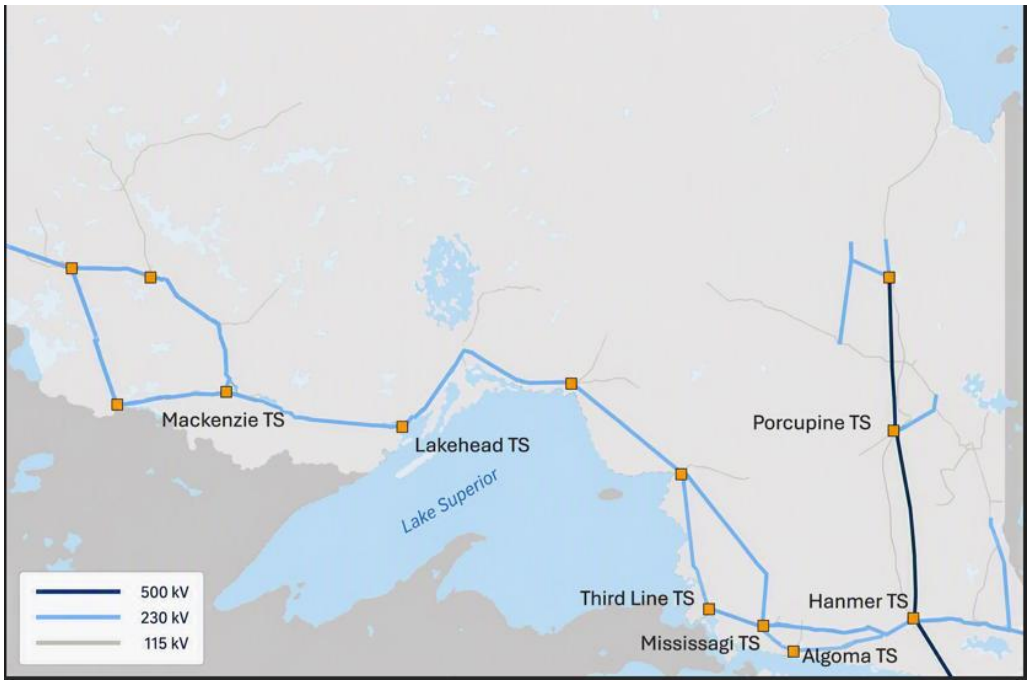

Figure 3: Map of System Reactive Reinforcements in Northern Ontario

In summary, IESO's letter and its recommendations that require investments within the rate period are:

8. Installation of two shunt reactors, each rated at 40 Mvar, at Lakehead TS and two new shunt reactors, each rated at 40 Mvar, at Mackenzie TS, as soon as practical, with a target in-service date of 2027.
9. Installation of one 500 kV, 120 Mvar line connected reactor at the Mississagi end for the planned new 500 kV circuit from Hanmer TS to Mississagi TS and two 100 Mvar STATCOMs, one at Mississagi TS and one at Algoma TS, with a target in-service date of 2029.

Recommendations 8 and 9 have led to multiple projects to install reactive support devices at locations above, in which the recommended scope is integrated with other on-going projects where practical. For example, the installation of new reactors at Mackenzie TS is integrated with Waasigan Project (T-SS-16), installation of new STATCOMs at Mississagi TS and Algoma TS are integrated with the North Shore Link project (see Appendix A, T-SS-11.03), and the installation of the 500 kV reactor is integrated with the Northeast Power

Line project (see Appendix A, T-SS-11.02). Two 40 Mvar reactors will be installed at Lakehead TS as a standalone project (see Appendix A, T-SS-11.05).

North – South Transmission Reinforcement Plan (Completed – 2025)

The North–South Transmission Reinforcement Plan was developed by the IESO to support growing electricity demand and enable additional generation development in Northern Ontario (See Figure 4) by increasing transfer capability, thereby helping Ontario meet its future energy and capacity needs as identified in IESO's Annual Planning Outlooks. The study identified that the need for reinforcement is currently most evident during overnight hours, when energy-limited hydroelectric resources in Northern Ontario reduce output to conserve water after supporting provincial peak demand periods. However, this need is expected to expand across all hours of the day due to continued demand growth in Northern Ontario and the potential retirement of aging thermal generation facilities.

Figure 4: Map of North – South Transmission Reinforcement Area

To address these needs, IESO recommendations that require investments within the rate period are:

10. Build a new single-circuit 500 kV series-compensated transmission line between Essa TS (Barrie) and Hanmer TS (Sudbury), install new series capacitor with similar characteristics to existing series capacitors on X503E and X504E at Nobel SS, and shunt line reactor with similar sizes to existing Hanmer reactors, with targeted in-service date of 2032.
11. Initiate early development work on a second new single-circuit 500 kV transmission line between Essa TS and Hanmer TS to preserve future options as demand and

supply resource developments unfold; construction will proceed if conditions warrant.

12. Review and modify selected Remedial Action Schemes at Hanmer TS, Essa TS and Pinard TS, including conversion of the two schemes at Hanmer TS and Essa TS to voltage-based triggering, with targeted in-service date of 2032.

Recommendations 10 to 12 have led to the development of the Sudbury Barrie Transmission Line project with necessary station and protection scheme work at Hanmer TS and Essa TS to accommodate the new circuit as well as a new series compensated capacitor at Nobel SS for the new circuit (see Appendix A, T-SS-11.06). The line portion of the project will be included in a separate ATP and the corresponding expenditures are therefore excluded from this Application.

North of Sudbury Bulk Plan (Completed – 2026 Q3)

The North of Sudbury Bulk Plan was initiated by the IESO in January 2025 to address growing electricity demand driven by mining and industrial activity in the Timmins, Kirkland Lake, and Pinard areas, as well as to assess constraints in the existing transmission network north of Sudbury (see Figure 5). The recommendations by the IESO, released in August 2026, are structured in three phases. Only Phase 1 requires investment within the 2028-2032 rate period. At this stage, future phases have not been triggered by the IESO, and the timeline and scope are subject to change based on factors including, but not limited to, future load forecast projections and future system conditions.

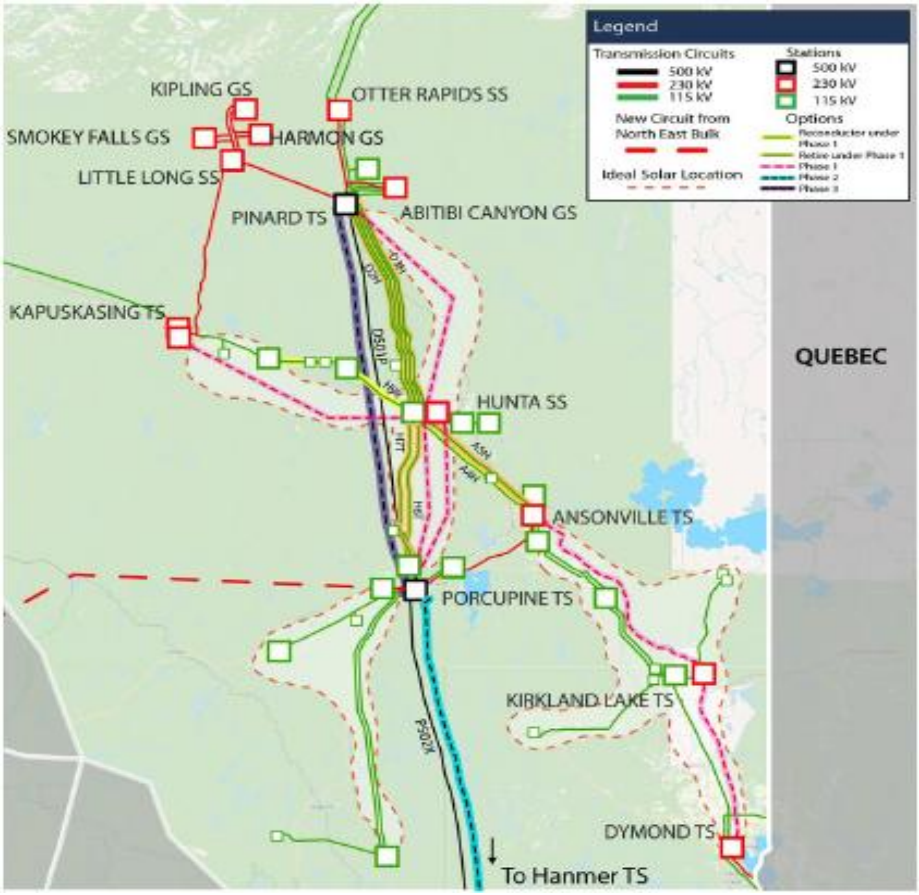

Figure 5: Map of North of Sudbury Bulk Plan Area (Phases 1, 2 and 3)

The forecast investments arising from the North of Sudbury Bulk Plan are based on IESO draft recommendations. The IESO has since released final bulk plans for the region on August 20, 2026. Planning and development for these investments is ongoing. To the extent that updated estimates become available, Hydro One will update this Application to reflect any material changes to forecast capital expenditures.

The following recommendations provided by the IESO require investment in the 2028-2032 rate period.

<u>Phase 1 – Implementation-Ready</u>

13. Complete the 230 kV connection between Iroquois Falls and Temiskaming Shores via the Kirkland Lake area.
14. Rebuild 115 kV circuits north of Timmins.

Witness: Mark Brodie

15. Build new 230 kV circuits, in addition to rebuilding existing end of life 115 kV circuits north of Timmins, to enable up to 430MW of hydroelectric generation connections in the Mosse River Basin area, as announced by the government in 2025 related to proposed hydroelectric generation expansions by Ontario Power Generation (OPG) in partnership with Taykwa Tagamou Nation (TTN) and Moose Cree First Nation (MCFN).[12]

The line portions of each project arising from recommendations 13, 14 and 15 will be owned by ATPs, therefore the corresponding expenditures are excluded from this Application.

Recommendation 13 has led to the development of a single 230 kV circuit from Hydro One's Ansonville TS (located close to Iroquois Falls) to Dymond TS (located close to Temiskaming Shores), with the new line sectionalizing at Kirkland Lake TS. Necessary 230 kV station expansion is required at the above three stations to accommodate the new line (see Appendix A, T-SS-11.07).

Recommendation 14 has led to circuit reconductor project on the existing H9K circuit west of Hunta SS to Carmichael Falls Jct (see Appendix A, T-SS-11.08), as well as reconductor an existing 115 kV circuit in the A4/5H corridor (see Appendix A, T-SS-11.09).

Recommendation 15 has led to the development of multiple circuits north of the Timmins area to allow for the connection of resources in that region, including a single 230 kV circuit from Hunta SS to Pinard TS for approximately 90 km, a double circuit 230 kV line from Porcupine TS to Hunta SS for approximately 70 km, and a single 230 kV line from Hunta SS to Kapuskasing TS for approximately 90 km, along with necessary 230 kV station expansions at the above four stations (see Appendix A, T-SS-11.10 and T-SS-11.11).

The remaining two phases, described below, are recommended by the study for future development, but have not triggered investments in this rate period at this time.

[12] See https://news.ontario.ca/en/release/1005756/ontario-pursuing-new-hydroelectric-stations-in-northern-ontario.

Phase 2 – Future-Ready Development: Sudbury to Timmins

16. Advance early development of a new bulk transmission path between Sudbury and Timmins, with construction to proceed only if future demand or system conditions meet identified triggers.

Phase 3 – Future-Ready Development: Timmins to Pinard

17. Initiate early development work for a 500 kV bulk transmission path between Timmins and Pinard TS, and coordinate development alongside Phase 2 to minimize incremental effort and preserve optionality, with construction to proceed only if system triggers are reached.

South and Central Ontario Bulk Plan (Completed – 2026 Q3)

The South and Central Ontario Bulk Plan assesses long-term transmission supply capability, reliability needs, and portfolios of infrastructure options required to support significant demand growth and electrification in the GTA, Central Ontario and Southwestern Ontario sub-regions (see Figure 6).

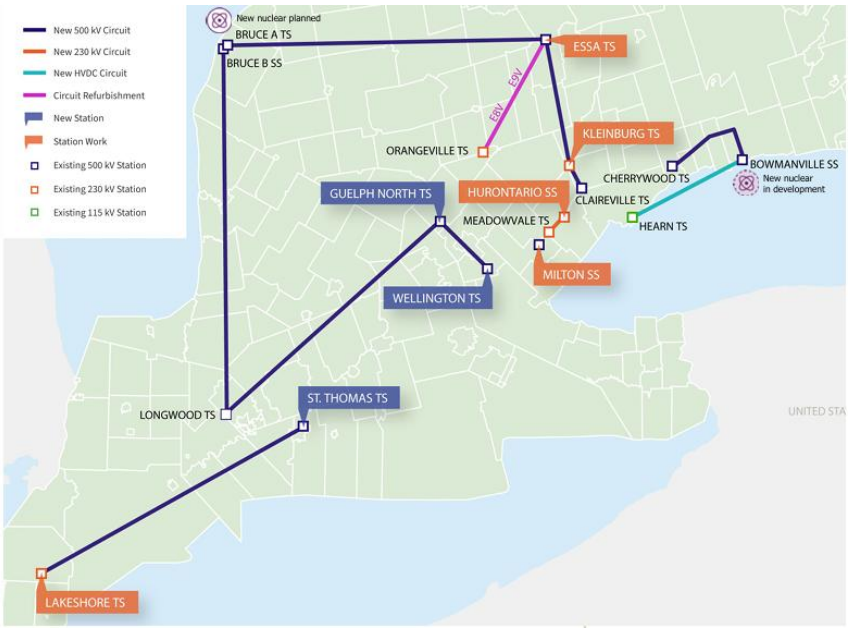

Figure 6: Map of South & Central Ontario Bulk Planning Region

The forecast investments arising from the South and Central Ontario Bulk Plan are based on IESO draft recommendations. The IESO has since released final bulk plans for the region on August 20, 2026. Planning and development for these investments is ongoing. To the extent that updated estimates become available, Hydro One will update this Application to reflect any material changes to forecast capital expenditures.

The following recommendations provided by the IESO, by sub-region (Module), require investments in the 2028-2032 rate period:

<u>East of Toronto Module</u>

18. New 500 kV Bowmanville-to-GTA East transmission line to enable Darlington SMRs, with a targeted in-service of 2032. This recommendation has led to the development of the Bowmanville SS Expansion project (see Appendix A, T-SS-11.12), as well as station work to expand the existing Bowmanville SS and reconfigure the existing Cherrywood TS to accommodate the new double-circuit 500 kV transmission line (see Appendix A, T-SS-11.13). The line portion of the project will be owned by an ATP, therefore the associated expenditures are excluded from this Application.

19. Third Supply to Toronto via submarine HVDC transmission line, approximately 65 km in length, with targeted in-service of 2037 or earlier, to reinforce electricity supply into the City of Toronto. This has led to the development of station work projects that will expand Hydro One's Bowmanville SS and Hearn SS to accommodate the new line, including any facilities necessary to interface with new HVDC convertor stations (see Appendix A, T-SS-11.14). The line portion of the project will be implemented through the separate IESO-administrated Transmission Selection Framework. Based on IESO public engagement material dated April 9th, 2026, "*Competitive Transmission Procurement: Toronto Third Line RFP and Contract Design update*", the IESO has communicated a targeted timeline of Q1 2027 to launch its Request for Proposal, with proposal evaluations and awarding in Q3 and Q4 2027.

GTA North Module

20. New Kleinburg 500/230 kV autotransformer station to provide additional supply capacity to Northern York and Peel Regions.
21. New Kleinburg to Kirby double-circuit 230 kV transmission line (Kleinburg – Kirby Transmission Link), of approximately 6 km in length, to provide additional supply capacity to Northern York and Peel Regions.
22. New Kleinburg to Claireville single-circuit 500 kV transmission line, of approximately 11 km in length, to enable Kleinburg 500/230 kV auto transformer station and provide reliable supply.
23. Essa to Orangeville transmission line reconductoring to enable new load connections in the region.
24. New autotransformer in Essa TS to enable new load connections in the area.

The line projects in recommendations 21 and 22 are not expected to meet Hydro One's ATP inclusion threshold and are therefore included in this Application.

Recommendations 20 and 21 have led to the Transmission Reinforcement Project for Northern York Region with targeted in-service in 2031-2032 (see Appendix A, T-SS-11.15), which includes the development of a new auto transformer station at Kleinburg TS, and new line development for the Kleinburg – Kirby Transmission link.

Recommendation 22 has led to the development of a single-circuit 500 kV transmission line from Claireville TS to Kleinburg TS (see Appendix A, T-SS-11.16) with necessary station expansion to accommodate the new 500 kV line with targeted in-service 2031-2032 (see Appendix A, T-SS-11.17)

Recommendation 23 has led to the E8V/E9V 230 kV transmission line upgrade project with targeted in-servicing in 2030 (see Appendix A, T-SS-11.18), where approximately 57 km of an existing Hydro One owned 230 kV line will be reconductored with higher rated conductors. As this is a reconductoring of an existing Hydro One owned line, it will not be owned by an ATP.

Recommendation 24 has led to the expansion of Essa TS to accommodate a new 500/230 kV autotransformer with one new 500 kV infrastructure bus for its connection with targeted in-service in 2032 (see Appendix A, T-SS-11.19).

GTA West Module

25. Expand Milton TS with new 500/230 kV autotransformers to provide additional supply to GTA East/Halton and Peel Region. This has led to the investment to expand the existing Milton 500 kV TS to accommodate new auto-transformers and a new 230 kV switchyard with targeted in-servicing in 2033 (see Appendix A, T-SS-11.20)

Southwest Module

26. New Guelph North 500 kV auto-transformer station to enable urgent economic growth, electrification and municipal development. This has led to the investment to develop the 500-230 kV Guelph North TS with targeted in-servicing in 2032 (see Appendix A, T-SS-11.21).
27. New St. Thomas 500 kV auto-transformer station to provide supply capacity to enable significant industrial and residential growth in the London Area. This has led to the investment to develop the St. Thomas auto-transformer station with targeted in-servicing in 2032 (see Appendix A, T-SS-11.22).
28. New single circuit 500 kV line from Longwood to Guelph North TS, and on to Wellington TS, which is required to enable electricity supply to the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region and support bulk transmission interfaces from southwest Ontario to the rest of the province. This has led to the investment with necessary station expansion work at Longwood TS to accommodate the new circuit with targeted in-service 2034. (see Appendix A, T-SS-11.23). Hydro One expects that the line portion of the project will be owned by a separate ATP and therefore the corresponding expenditures are excluded from this Application. The construction of Wellington TS was recommended by the IESO through the KWCG Regional Planning process, discussed in ISD T-SS-12.

Eastern Ontario Bulk Plan (Completed - 2026 Q3)

The Eastern Ontario Bulk Plan assesses long-term transmission supply capability, reliability needs, and infrastructure required to support significant demand growth and electrification in two focused areas (Modules), namely the Belleville sub-region and Ottawa sub-region.

The forecast investments arising from the Eastern Ontario Bulk Plan are based on IESO draft recommendations. The IESO has since released final bulk plans for the region on August 20, 2026. Planning and development for these investments is ongoing. To the extent that updated estimates become available, Hydro One will update this Application to reflect any material changes to forecast capital expenditures:

<u>Belleville Region Module</u>

29. New 230 kV double-circuit line from Napanee to Belleville, as well as a station expansion in Belleville TS to accommodate new circuits with a new 100 Mvar of reactive compensation (see Figure 7). This has led to the station expansion work at Belleville TS to connect the X21/X22 extension and the installation of a new 100 Mvar STATCOM (see Appendix A, T-SS-11.24). Hydro One expects that the line portion of the project will be owned by an ATP, therefore the corresponding expenditures are excluded from this Application.

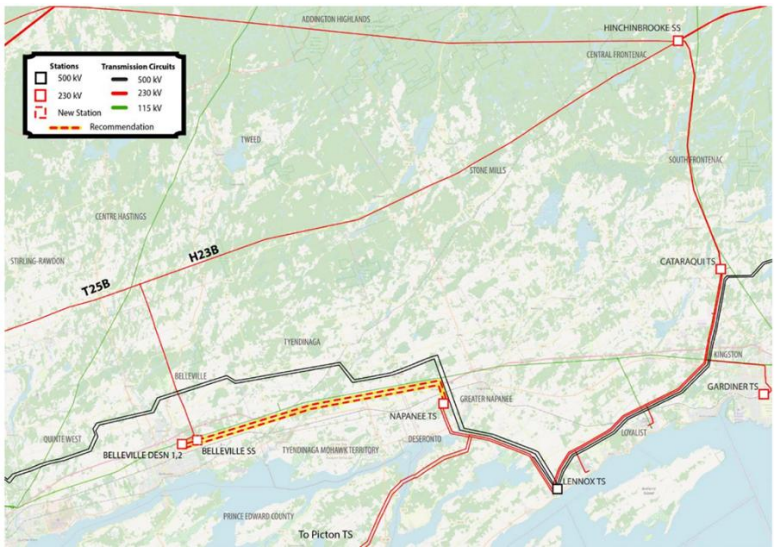

Figure 7: Map of Eastern Ontario Bulk Planning Region (Belleville Subregion)

Ottawa Region Module

30. New 230 kV double-circuit line, for approximately 80 km, from St. Lawrence TS to Merivale TS (see Figure 8), which has led to the station expansion work on both St. Lawrence TS and Merivale TS to accommodate the new transmission line, (see Appendix A, T-SS-11.25). Hydro One expects that the line portion of the project will be owned by an ATP and associated expenditures are therefore excluded from this Application.
31. Station work at Hawthorne TS to mitigate a thermal limitation on the existing autotransformer T3, with 200 Mvar of additional reactive support. This has led to the addition of a new 500 kV breaker at Hawthorne TS (see Appendix A, T-SS-11.26), as well as the construction and installation of a new 230 kV STATCOM at Hawthorne TS.

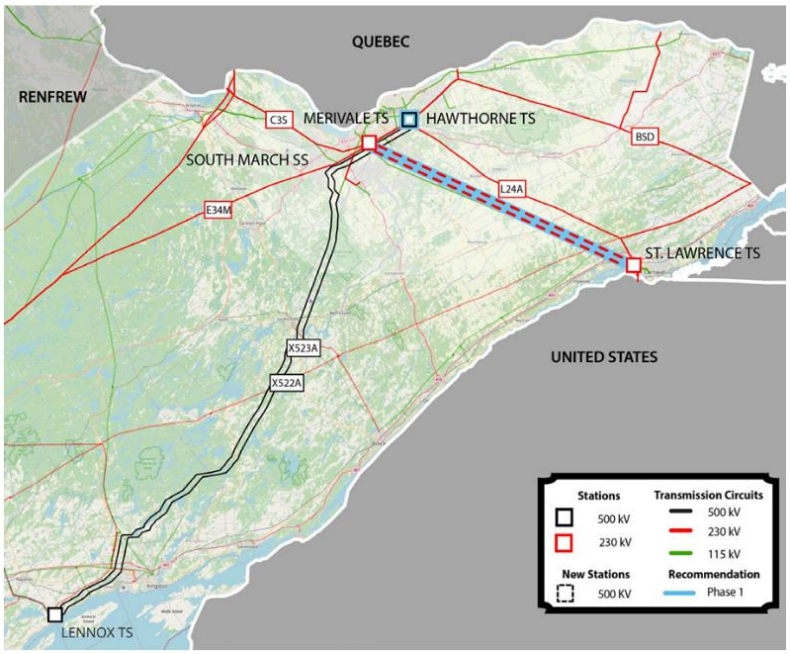

Figure 8: Map of Eastern Ontario Bulk Planning Region (Ottawa Subregion)

Orders-in-Council and Ministerial Directives

Notably, for some of the projects that have been included in the bulk planning investment portfolio, in addition to having been identified through IESO bulk system planning recommendations, OICs have been issued by the Government of Ontario declaring the

projects to be priority transmission projects, pursuant to Section 96.1 of the *Ontario Energy Board Act, 1998*. In addition, Minister's Directives have been issued for some projects, directing the OEB to amend Hydro One's transmission licence so as to require Hydro One to develop and seek approvals necessary for carrying out the project. The relevant OICs are listed in Table 2. As stated in the OICs, applicable to the investments listed in Table 2, the Government of Ontario considers the expansion of Ontario's transmission system critical to providing "a reliable and adequate supply of electricity" that supports economic growth in various areas of the province, including Northeastern, Eastern, Southern, and Northern Ontario.[13] These investments support economic growth in key sectors, such as the rapidly growing mining and agricultural sectors, as well as anticipated growth in hydroelectric and nuclear generation.[14] Accordingly, these investments are essential to enable electrification and support continued economic development and growth across Ontario, consistent with the policies of the Government of Ontario.

As noted above, where the line component of the investment will be owned by an ATP, capital expenditures are included only for the stations component of the investment.

Table 2 - Bulk Planning Projects with OICs

Date	OIC #	Summary	ISD Ref
October 19, 2023	1531/2023[15] 1532/2023[16]	Development and construction of the transmission line(s), including associated station facility expansions or upgrades required at the terminal stations: - A new 230 kV transmission line from Dobbin Transformer Station to either Cherrywood Transformer Station or Clarington Transformer Station - A new 500 kV transmission line from Mississagi Transformer Station to Hanmer Transformer Station - A new 230 kV transmission line from Mississagi Transformer Station to Third Line Transformer Station Pursuant to Ministerial Directive, Hydro One's Transmission Licence has been amended to develop and seek approvals for the projects.	T-SS-11.01 T-SS-11.02 T-SS-11.03

[13] OIC 1554/2024. See also OICs 1531/2023, 1377/2025, 1663/2025.
[14] OIC 1663/2025; OIC 1377/2025.
[15] See Order in Council 1531/2023 | ontario.ca
[16] See Order in Council 1532/2023 | ontario.ca

November 28, 2024	1554/2024[17] 1555/2024[18]	A new 230 kilovolt (kV) transmission line (built to 500 kV standards) from Wawa Transformer Station to Porcupine Transformer Station, including associated station facility expansions or upgrades required at these terminal stations. Pursuant to Ministerial Directive, Hydro One's Transmission Licence has been amended to develop and seek approvals for the project.	T-SS-11.04
October 23, 2025	1377/2025[19]	Reconductoring of Hydro One Network Inc.'s existing 230-kilovolt transmission lines (E8V / E9V) between Orangeville and Barrie. Development and construction of the transmission line(s), including associated station facility expansions or upgrades required at the terminal stations of: - New 230 kV double circuit from Windsor to Lakeshore, which is further described in ISD T-SS-12.01 - New double 500 kV transmission line from Bowmanville to Greater Toronto Area Pursuant to Ministerial Directive, Hydro One's Transmission Licence has been amended to develop and seek approvals for the projects.	T-SS-11.18 T-SS-11.13
December 11, 2025	1663/2025[20]	Development and construction of one new single-circuit 500-kilovolt transmission line from the Essa Transformer Station to the Hanmer Transformer Station, including associated station facility expansions or upgrades required at the terminal stations Pursuant to Ministerial Directive, Hydro One's Transmission Licence has been amended to develop and seek approvals for the project.	T-SS-11.06

Unallocated Regional Planning Amounts

The IESO-led Bulk System Planning Process is expected to continue, with Niagara region bulk planning having commenced in Q2 2026 and recommendations to follow through 2027. Recognizing this ongoing nature of Bulk System Planning, this investment portfolio includes an unallocated amount for which the scope has yet to be determined but which will not form part of an ATP (see Appendix A, T-SS-11.27). This work will be undertaken in accordance with future Bulk System Planning recommendations to be provided by the

[17] https://www.oeb.ca/sites/default/files/OC-1554-2024.pdf
[18] Order in Council 1555/2024 | ontario.ca
[19] https://www.ontario.ca/orders-in-council/oc-13772025
[20] https://www.ontario.ca/orders-in-council/oc-16632025

IESO, for investments identified as being required over the 2028-2032 period. The unallocated amount, as presented in Table B1 of Appendix B, is budgeted to address $250M worth of future work that must commence between 2028-2032 to meet the IESO's recommended in-servicing timelines, and represents approximately 5% of the total portfolio expenditure under this investment. Hydro One believes the unallocated amount to be reasonable given that scope has not yet been determined and the targeted in-servicing timelines for larger projects may extend beyond 2032.

As Hydro One expects greater certainty in the near term (2028-2030), the lower net amounts in 2028 and 2029 reflect a lower risk of near-term unknowns. Longer-term (2030-2032), expenditures are forecasted to rise to account for the unprecedented system expansions that Ontario's electrical infrastructure is expected to experience. This investment will fund projects proposed in response to specific needs identified during the bulk planning process; alternatives (if any) will be reviewed as part of this planning process.

3.0 INVESTMENT DESCRIPTION

This investment is comprised of projects that will be undertaken on or in relation to various Hydro One owned network assets to implement bulk level reinforcements and expansions as recommended by the IESO in the bulk planning studies described above. The nature of the work includes expansion and/or modification of existing Hydro One owned stations to provide additional transmission circuit termination facilities; adding or upsizing existing equipment (such as adding new autotransformers) and/or station infrastructure (such as ground grid expansion), or a combination of the above. Each project also includes all necessary protection and control modifications required to integrate new station components. In certain projects, where recommended by the IESO, one or more new stations will be constructed. At the time of finalizing investment planning, most projects under this investment are in the project definition and development phase, where pre-construction activities such as, but not limited to, environmental assessment, establishment of the project management office, preliminary engineering designs, and procurement of long lead materials are undertaken. The list of projects, with a summary of the scope and the bulk planning study that the project is responsive to, along with main voltage levels and summary level asset additions, is provided in Appendix A.

The line portions of various bulk system projects, and their associated capital expenditures, are generally not captured in this investment as they will be owned by ATPs. There are three line projects where expenditures are included. Expenditures for the E8V/E9V 230 kV Transmission Line Upgrade (T-SS-11.18) are included as it is a reinforcement of the existing Hydro One owned and operated E8V/E9V circuit. Two line projects are not expected to meet the ATP inclusion threshold of $100M: the Kleinburg – Kirby Transmission Link (part of T-SS-11.15), which is approximately 6 km in length; and the Kleinburg – Claireville transmission line (T-SS-11.16), which is approximately 11 km in length.

System Impact Assessments (SIA) and Customer Impact Assessments (CIA) will be conducted at the individual project level, where applicable, to confirm that each project will not adversely affect the reliability of the IESO-administered grid or Hydro One's existing transmission customers. Depending on individual project scopes, environmental assessment, First Nation consultation and community engagement activities, in line with standard Hydro One project execution practices and applicable legal requirements, may be undertaken at a project level to identify and mitigate impacts.

4.0 OUTCOMES

IESO bulk planning is undertaken with the overall objective of ensuring both near-term and long-term transmission system adequacy, maintaining or improving transmission reliability, and enabling load growth from electrification and long-term economic development in Ontario. This investment responds to and implements recommendations made by the IESO in the seven bulk system studies described herein, and in some cases as further supported by OICs and transmission licence obligations imposed on Hydro One, for the development and construction, expansion or reinforcement of transmission network facilities to support the IESO's overall objectives of addressing Ontario's bulk electricity system needs and ensuring the transmission capacity to address province-wide electricity needs, while maintaining compliance with applicable reliability standards and criteria.

4.1 OEB RRF OUTCOMES

Table 3 summarizes the anticipated benefits of the investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 3 - Outcomes Summary

Customer Focus	• Maintain and enable new, reliable power delivery at the bulk level
Operational Effectiveness	• Improve operational effectiveness and power transfer capability at the bulk level
Public Policy Responsiveness	• Ensure compliance with applicable regulatory requirements and respond to provincial policy initiatives

5.0 EXPENDITURE PLAN

Table 4 summarizes Hydro One's forecast capital expenditures for this investment over the 2028-2032 rate period.

Table 4 - Hydro One - Investment Expenditures[21,22]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	763.9	1,044.4	1,098.2	1,291.6	939.4	5,137.5
Less Removals	1.5	2.0	1.2	0.1	0.0	4.7
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**762.4**	**1,042.4**	**1,097.0**	**1,291.6**	**939.4**	**5,132.8**

Given the long-lead time for, and complex nature of these bulk system projects, the forecasted capital expenditures for projects included in this investment have been developed by Hydro One based on analysis of historical costs for completed or recently estimated projects that have similar project scopes. These investments are complex and are undertaken over several years in accordance with the Capital Project Delivery Model discussed in TSP Section 2.11. At the time of filing this Application, most projects are in the Planning and Definition phase, during which the scope, design and execution plans are being further defined. Cost and schedule accuracy are therefore expected to improve as the individual projects progress.

As proposed in Exhibit G-01-03 Section 3.1, the Externally Driven Transmission Projects Variance Account will be used to record the revenue requirement impact of variances

[21] Figures presented in the tables may not sum to the totals shown due to rounding.
[22] Forecast net capital expenditures for the 2028-2032 period include $4.5M of immaterial projects.

between the in-service additions embedded in Hydro One's approved revenue requirement relating to this investment and the actual in-service additions for this investment over the 2028-2032 period.

6.0 ALTERNATIVES

ALTERNATIVE 1: STATUS QUO

This alternative is rejected as Hydro One considers projects recommended by the IESO pursuant to its authority under the *Electricity Act, 1998* for bulk system planning in Ontario, where Hydro One is expressly or implicitly the transmitter responsible for implementing the recommended transmission solution, to be non-discretionary. Further, seven of the 26 material investments resulting from bulk recommendations are the subject of OICs from the provincial government making them priority transmission projects. Under amendments to Hydro One's Transmission Licence, it is obligated to develop these projects. Maintaining status quo / inaction will significantly impact Ontario's ability to meet its future electricity needs, result in inadequate capacity and unreliable transmission service in different parts of Ontario, and will result in Hydro One not complying with its obligations as a licensed Ontario transmitter.

ALTERNATIVE 2: PROCEED WITH IESO RECOMMENDATIONS ONLY WHEN DIRECTED UNDER AN OIC, MINISTERIAL DIRECTIVE OR SIMILAR

This alternative is rejected as each recommendation made by the IESO in its various bulk system plans is required to address defined bulk system needs with targeted timelines, where options for addressing identified needs (including non-wires options) have been thoroughly analyzed by the IESO, in consultation with participating stakeholders, and where the IESO has then concluded that each recommended solution achieves the best cost-benefit for the identified need that the solution will address. It is not prudent to proceed with IESO recommendations only when Hydro One is formally directed by means of an OIC, Ministerial Directive, or governmental instrument of a similar nature, as it would introduce unnecessary delay for the needed bulk electric infrastructure as recommended by IESO. Such inaction would in turn put the reliability and supply adequacy of Ontario's bulk transmission system at risk as provincial load levels continue to rise, and ultimately

delay various new load and generation connections, broader electrification, and economic growth in the province.

ALTERNATIVE 3: PROCEED WITH IESO RECOMMENDATIONS (RECOMMENDED)

This preferred alternative proactively responds to and implements recommendations made by the IESO in seven specific bulk system planning studies. Each recommendation made by the IESO in its various bulk system plans is required to address defined bulk system needs with targeted timelines, where options for addressing identified needs (including non-wires options) have been thoroughly analyzed by the IESO, in consultation with participating stakeholders, and where the IESO has then concluded that each recommended solution achieves the best cost-benefit for the identified need that the solution will address. In addition, for seven projects, as set out in Table 2, the Government of Ontario has issued OICs designating them priority transmission projects and directives that impose on Hydro One a licence obligation to develop the project. This alternative expands and reinforces the bulk transmission system to meet provincial load growth and electrification projections, and enables new load and generation connections across the province. This alternative also allows Hydro One to fulfill its obligations as a transmitter pursuant to its Transmission Licence and the TSC.

7.0 EXECUTION RISK AND MITIGATION

As described in TSP Section 2.11, Hydro One follows a Transmission Capital Project Delivery Model, throughout which project risks are identified and mitigation plans are implemented. Risks that can impact the completion of various transmission projects that include station and/or line components include:

- Outage constraints: Planned outages are required to replace assets and may involve individual assets, sections of a station, or the entire station. Hydro One plans and coordinates outages to minimize impacts on customers while providing construction and commissioning staff with the access required to complete the work.
- Resource constraints: Projects in the same geographical location may require the same construction and commissioning resources. Hydro One coordinates project

schedules and resource requirements to manage competing demands for these resources.

- Construction execution challenges: Existing station equipment may require retrofits to accommodate new assets because station designs and equipment standards have evolved. Significant design and construction may also be required where assets cannot be replaced in the same physical location due to space constraints, outage requirements or safety considerations.
- Real estate requirements: Station expansion and new land may be required when assets cannot be replaced in the same physical location.
- Environmental Assessment, First Nation consultation and community engagement: New land requirements can trigger requirements for environmental assessment, First Nations consultation and community engagement activities, which may influence project timelines. Hydro One addresses these considerations through early engagement and consultation planning to support meaningful participation, and where applicable, co-develop a community engagement plan offering community benefits frameworks for employment pathways and contracting opportunities.
- Procurement challenges: Equipment procurement lead times can be long. Hydro One engages vendors at appropriate times in the planning process to ensure sufficient lead time to obtain major equipment.
- Regulatory challenges: Certain new transmission line or upgrade projects will require leave to construct applications and approvals. Hydro One prepares the necessary filing documents with sufficient engineering and cost details, informed by detailed estimates, to fulfill its regulatory obligations related to Section 92 of the *Ontario Energy Board Act, 1998*.

APPENDIX A – DESCRIPTION OF FORECAST INVESTMENTS

This Appendix describes each material investment for the 2028-2032 period and the forecast capital expenditures.

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
T-SS-11.01	Durham Kawartha Power Line – Station	Expand existing Dobbin TS and Clarington TS to accept the new 230 kV double-circuit transmission line Prior to 2028, this project is expected to complete project definition and scoping phase. Long lead time material would be purchased. Project execution is also expected to commence in Q1 2027.	Gatineau Corridor End of Life study (2022)	230	-	10	-	35.5	97.2
T-SS-11.02	Northeast Power Line: Mississagi x Hanmer Reinforcement - Station	Expand existing Hanmer TS to accept one new 500 kV transmission line; Construct new 500 kV switchyard at Mississagi TS with 2 new 500 kV autotransformers. Prior to 2028, this project is expected to complete project definition and scoping phase. Long lead time material would be purchased. Project execution is also expected to commence in Q4 2027.	Need for Northeast Bulk System Reinforcements (2022)	500	2	14	-	225.0	578.7

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
T-SS-11.03	North Shore Link: Mississagi x Third Line Reinforcement - Station	Expand existing Mississagi TS to accept two (2) new transmission lines; install STATCOM at Mississagi and Algoma TS. Prior to 2028, this project is expected to complete project definition and scoping phase. Long lead time material would be purchased. Project execution is also expected to commence in Q4 2027.	Need for Northeast Bulk System Reinforcements (2022)	230	-	7	2	125.9	374.0
T-SS-11.04	Wawa Timmins Powerline - Station	Expand existing Wawa TS and Porcupine TS to accept one new 230 kV transmission line; reserve real estate for ultimate construction of 500 kV switchyard with autotransformers at Wawa (future). Prior to 2028, this project is expected to complete project definition and scoping phase. Project execution is also expected to commence in Q4 2027.	Need for Northeast Bulk System Reinforcements (2022)	230	-	4	-	89.3	100.1
T-SS-11.05	Lakehead TS: Install reactors	Install two 40 Mvar reactor. Prior to 2028, this project is expected to complete project	Bulk System Reactive Requirements	230	-	1	2	17.5	22.5

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
		definition and scoping phase. Project execution is also expected to commence in Q2 2027.	in Northern Ontario (2023)						
T-SS-11.06	Sudbury Barrie Transmission Line - Station	Expand existing Hanmer TS and Essa TS to accept one new 500 kV transmission line; install three single phase reactor at Hanmer TS; install one (1) fixed series capacitor bank at Nobel SS. Prior to 2028, this project is expected to begin project definition and scoping phase.	North-South Transmission Reinforcement Plan (2025)	500	-	6	4	360.0	392.0
T-SS-11.07	New 230 kV Line: Dymond x Kirkland Lake x Ansonville - Station	Expand 230 kV switchyard at Ansonville TS and Dymond TS. Construct new 230 kV switchyard with autotransformers at Kirkland Lake TS to accommodate new 230 kV line. Prior to 2028, this project is expected to begin project definition phase.	North of Sudbury Bulk Plan (2026 Q3)	230	2	TBD	-	100.0	210.0
T-SS-11.08	H9K Reconductor	Reconductor existing H9K circuit from Hunta SS to the proximity of Carmichael Falls Jct with higher rated conductor.	North of Sudbury Bulk Plan (2026 Q3)	115	-	-	-	40.0	80.0

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
		Prior to 2028, this project is expected to begin project definition phase.							
T-SS-11.09	A4H or A5H Reconductor	Reconductor existing A4/5H circuit from Ansonville TS to Hunta SS. Prior to 2028, this project is expected to begin project definition phase.	North of Sudbury Bulk Plan (2026 Q3)	115	-	-	-	15.0	54.0
T-SS-11.10	230 kV station expansion at Porcupine TS, Hunta SS and Pinard TS	Expand 230 kV switchyard at Porcupine TS, Hunta SS and Pinard TS. Construct new 230 kV switchyard with autotransformer at Hunta SS to accommodate new 230 kV line. Prior to 2028, this project is expected to begin project definition phase.	North of Sudbury Bulk Plan (2026 Q3)	230	1	TBD	-	225.0	450.0
T-SS-11.11	230 kV station expansion at Kapuskasing TS Hunta SS	Expand 230 kV switchyard at Kapuskasing TS, along with new/expansion of 230 kV switchyard at Hunta SS to accommodate new 230 kV line. Hunta SS's scope of work to coordinate with T-SS-11.10.	North of Sudbury Bulk Plan (2026 Q3)	230	-	TBD	-	75.0	150.0

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
		Prior to 2028, this project is expected to begin project definition phase.							
T-SS-11.12	Bowmanville SS Expansion	Construct new 500 kV Bowmanville “B” Switching Station to connect OPG SMRs. Prior to 2028, this project is expected to complete project definition and scoping phase. Long lead time material would be purchased. Project execution is also expected to commence in Q2 2027.	South & Central Ontario Bulk Plan (2026 Q3)	500	-	18	-	900.1	999.1
T-SS-11.13	Build 500 kV line from Bowmanville SS to GTA East -Station	Expand existing Bowmanville SS and reconfigure Cherrywood TS to accept the new 500 kV double-circuit transmission line. Prior to 2028, this project is expected to begin project definition phase.	South & Central Ontario Bulk Plan (2026 Q3)	500	-	2	-	485.0	505.0
T-SS-11.14	New Supply to Central Toronto	Build necessary interfacing facility to enable future HVDC convertor stations at Hearn SS and Bowmanville SS. Prior to 2028, this project is expected to begin project definition phase.	South & Central Ontario Bulk Plan (2026 Q3)	TBD	2	TBD	TBD	131.0	270.0

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
T-SS-11.15	Transmission Reinforcement for Northern York Region	Construct new auto-transformer station at Kleinburg, with approximately 6 km of double 230 kV circuit from Kleinburg to Kirby area in existing transmission corridor. Prior to 2028, this project is expected to begin project definition phase.	South & Central Ontario Bulk Plan (2026 Q3) - GTA North	500 & 230	5	27	-	428.2	441.0
T-SS-11.16	New Claireville x Kleinburg 500 kV - Line	Construct single circuit 500 kV line from Claireville TS to Kleinburg TS for approximately 11 km in existing transmission corridor. Prior to 2028, this project is expected to the begin project definition phase.	South & Central Ontario Bulk Plan (2026 Q3) - GTA North	500	-	-	-	97.0	100.0
T-SS-11.17	New Claireville x Kleinburg - Station	Expand Claireville TS 500 kV GIS and Kleinburg 500 kV switchyard to accommodate new circuit. Kleinburg TS station scope to coordinate with T-SS-11.15. Prior to 2028, this project is expected to begin the project definition phase.	South & Central Ontario Bulk Plan (2026 Q3) - GTA North	500 & 230	-	TBD	-	97.0	100.0

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
T-SS-11.18	Orangeville x Barrie Reconductor (E8V/E9V 230 kV Transmission Line Upgrade)	Reconductor approximately 57 km of E8V/E9V circuit. Prior to 2028, this project is expected to complete the project definition and scoping phase.	South & Central Ontario Bulk Plan (2026 Q3) - GTA North	230	-	-	-	98.0	123.0
T-SS-11.19	Essa TS - 750MVA 500/230 kV Autotransformer	Expand existing Essa TS to accommodate a new 500/230 kV autotransformer with 1 new 500 kV bus. Prior to 2028, this project is expected to complete the project definition and scoping phase.	South & Central Ontario Bulk Plan (2026 Q3) - GTA North	500	1	4	-	49.0	64.0
T-SS-11.20	Milton TS Expansion	Expand Milton TS to accommodate new auto-transformers and new 230 kV switchyard. Prior to 2028, this project is expected to begin the project definition phase.	South & Central Ontario Bulk Plan (2026 Q3) - GTA West	500 & 230	2	13	-	370.0	450.0
T-SS-11.21	Guelph North TS Development	Construct new auto-transformer station at vicinity of Guelph North Jct. Prior to 2028, this project is expected to begin the project definition phase.	South & Central Ontario Bulk Plan (2026 Q3) - Southwest Ontario	500 & 230	2	23	2	295.0	300.0

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
T-SS-11.22	New 500 kV Station in St. Thomas	Construct new auto-transformer station in vicinity of St Thomas area. Prior to 2028, this project is expected to begin the project definition phase.	South & Central Ontario Bulk Plan (2026 Q3) - Southwest Ontario	500 & 230	2	20	-	295.0	300.0
T-SS-11.23	Longwood TS 500 kV Expansion	Expand Longwood 500 kV switchyard to accommodate new 500 kV single circuit going to Guelph North TS.	South & Central Ontario Bulk Plan (2026 Q3) - Southwest Ontario	500	-	2	-	105.0	150.0
T-SS-11.24	Napanee–Belleville 230 kV Transmission Reinforcement	Expand Belleville 230 kV switchyard to accommodate new 230 kV double circuit extension of X21/X22, with addition of 100 Mvar reactive compensation. Prior to 2028, this project is expected to begin the project definition phase.	Eastern Ontario Bulk Plan (2026 Q3) - Belleville Region	230	-	6	1	145.0	148.0
T-SS-11.25	New 230 kV Line: St. Lawrence TS x Merivale TS - Station	Expand St. Lawrene TS to Merivale TS 230 kV switchyard to accommodate new 230 kV double circuit for approximately 80 km.	Eastern Ontario Bulk Plan (2026 Q3) - Ottawa Region	230	-	4	-	60.0	60.0
T-SS-11.26	Hawthorne TS 500 kV Breaker addition	Modify existing Hawthorne TS to accommodate one additional 500 kV breaker.	Eastern Ontario Bulk Plan (2026 Q3) - Ottawa Region	500	-	1	-	15.0	15.0

ISD Ref.	Investment Name	Scope Summary	Corresponding Bulk Plans	Forecast Units (Upgrade / Install)				28-32 Total	Project Total
				Voltage (kV)	Trfr	Brkr	Reactive Device		
T-SS-11.27	Unallocated expenditures for Future Stations Work	Unallocated amount to account for upcoming recommendations from IESO bulk planning that is still on-going.	Niagara Bulk Plan/Other	-	-	-	-	-	-
	Total			**-**	**18**	**176**	**11**	**-**	**-**

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

The investments proposed in this ISD are complex and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.11. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project, the in-service year and the project total estimates for the 2023-2027 and 2028-2032 rate periods. Project maturity is defined by the following project phases:

- Execution (E), which reflects fully approved project work;
- Planning and Definition (P), which reflects non-execution work, regardless of level of upfront development; and
- Complete (C), which reflects that the project has been placed in service

At Hydro One, projects are governed with a focus on adherence to the total project budget. In-year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in the table below in reference to project total variances and overall project schedule variances.

The following investments had planned and actual capital expenditures during the 2023-2027 period but were expected to be placed in service outside of the rate period resulting in no planned or actual in-service additions during that period:

- T-SS-11.15 - Tx Reinforcement for Northern York Region; and
- T-SS-11.20 - Milton TS and 230 kV Lines.

In the 2028-2032 period, Hydro One expects total project costs for the investments listed above to be higher than the 2023-2027 period, primarily due to evolving IESO bulk planning assumptions and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historical material cost escalation trends are described in SPF Section 1.8.3, including transmission and distribution poles; conductors, cables and wires; high voltage circuit breakers; and power transformers, which have increased by 45%, 65%, 140% and 115%, respectively, on average since 2020.

1 **Table B1 - Hydro One - Detailed Material Investment Costs ($M)**

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[23]			
		Act/Fcst[24] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Serv Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
T-SS-11.01	Durham Kawartha Power Line - Station	**61.8**	27.9	7.5	0.0	0.0	0.0	**35.5**	P	97.2	2029	-	-	-	-
T-SS-11.02	Northeast Power Line: Mississagi x Hanmer Reinforcement – Station	**353.7**	146.9	72.1	6.0	0.0	0.0	**225.0**	P	578.7	2029	-	-	-	-
T-SS-11.03	North Shore Link: Mississagi x Third Line Reinforcement – Station	**248.1**	73.3	47.8	4.8	0.0	0.0	**125.9**	P	374.0	2029	-	-	-	-
T-SS-11.04	Wawa Timmins Powerline - Station	**10.8**	19.4	29.1	38.8	2.0	0.0	**89.3**	P	100.1	2030	-	-	-	-

[23] "Prior Project Forecast" refers to the forecast project total and in-service date when Hydro One revised the capital and ISA forecast to implement the OEB-approved Settlement Proposal in EB-2021-0110.
[24] "Act/Fcst" refers to actual (2023-2025) and forecast (2026-2027) expenditures.

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[23]			
		Act/Fcst[24] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Serv Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
T-SS-11.05	Lakehead TS: Install Reactors	**5.0**	8.2	9.2	0.0	0.0	0.0	**17.5**	P	22.5	2029	-	-	-	-
T-SS-11.06	Sudbury Barrie Transmission Line - Station	**22.0**	30.0	30.0	50.0	125.0	125.0	**360.0**	P	392.0	2032	-	-	-	-
T-SS-11.07	New 230 kV Line: Dymond x Kirkland Lake x Ansonville - Station	**5.0**	5.0	10.0	15.0	20.0	50.0	**100.0**	P	210.0	2034	-	-	-	-
T-SS-11.08	H9K Reconductor	**2.0**	5.0	5.0	10.0	10.0	10.0	**40.0**	P	80.0	2033	-	-	-	-
T-SS-11.09	A4H or A5H Reconductor	**1.0**	2.0	5.0	2.0	1.0	5.0	**15.0**	P	54.0	2033	-	-	-	-
T-SS-11.10	230 kV station expansion at Porcupine TS, Hunta SS and Pinard TS	**5.0**	10.0	20.0	55.0	65.0	75.0	**225.0**	P	450.0	2034	-	-	-	-
T-SS-11.11	230 kV station expansion at Kapuskasing TS Hunta SS	**5.0**	5.0	5.0	15.0	20.0	30.0	**75.0**	P	150.0	2034	-	-	-	-
T-SS-11.12	Bowmanville SS Expansion	**98.9**	113.5	171.7	169.0	320.0	125.9	**900.1**	P	999.1	2032	-	-	-	-

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[23]			
		Act/Fcst[24] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Serv Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
T-SS-11.13	Build 500 kV Line from Bowmanville SS to GTA East - Station	**15.0**	15.0	105.0	105.0	110.0	150.0	**485.0**	P	505.0	2032	-	-	-	-
T-SS-11.14	New Supply to Central Toronto	**2.0**	11.0	33.0	30.0	40.0	17.0	**131.0**	P	270.0	2034	-	-	-	-
T-SS-11.15	Transmission Reinforcement for Northern York Region	**12.8**	86.2	128.0	125.4	88.6	0.0	**428.2**	P	441.0	2031	-	P	90.7	2033
T-SS-11.16	New Claireville x Kleinburg 500 kV - Line	**3.0**	16.0	13.0	21.0	27.0	20.0	**97.0**	P	100.0	2032	-	-	-	-
T-SS-11.17	New Claireville x Kleinburg - Station	**3.0**	16.0	13.0	21.0	27.0	20.0	**97.0**	P	100.0	2032	-	-	-	-
T-SS-11.18	Orangeville x Barrie Reconductor (E8V/E9V 230 kV Transmission Line Upgrade)	**25.0**	30.0	40.0	28.0	0.0	0.0	**98.0**	P	123.0	2030	-	-	-	-
T-SS-11.19	Essa TS – 750MVA 500/230 kV Autotransformer	**15.0**	9.0	20.0	15.0	5.0	-	**49.0**	P	64.0	2031	-	-	-	-

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[23]			
		Act/Fcst[24] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Serv Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
T-SS-11.20	Milton TS Expansion	**9.0**	20.0	80.0	90.0	90.0	90.0	**370.0**	P	450.0	2033	-	P	298.8	2031
T-SS-11.21	Guelph North TS Development	**5.0**	40.0	60.0	85.0	90.0	20.0	**295.0**	P	300.0	2032	-	-	-	-
T-SS-11.22	New 500 kV Station in St. Thomas	**5.0**	40.0	60.0	85.0	90.0	20.0	**295.0**	P	300.0	2032	-	-	-	-
T-SS-11.23	Longwood TS 500 kV Expansion	**0.0**	0.0	0.0	15.0	30.0	60.0	**105.0**	P	150.0	2034	-	-	-	-
T-SS-11.24	Napanee–Belleville 230 kV Transmission Reinforcement	**3.0**	10.0	40.0	40.0	35.0	20.0	**145.0**	P	148.0	2032	-	-	-	-
T-SS-11.25	New 230 kV Line: St. Lawrence TS x Merivale TS - Station	**-**	2.0	5.0	25.0	14.0	14.0	**60.0**	P	60.0	2032	-	-	-	-

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[23]			
		Act/Fcst[24] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Serv Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
T-SS-11.26	Hawthorne TS - Breakers	**-**	1.0	3.0	6.0	5.0	-	**15.0**	P	15.0	2031	-	-	-	-
T-SS-11.27	Unallocated expenditures for Future Stations Work	**-**	20.0	30.0	40.0	75.0	85.0	**250.0**	-	-	-	-	-	-	-

APPENDIX C - HYDRO ONE SAULT STE. MARIE (HOSSM)

Recommendation 5 of the IESO's Need for Northeast Bulk System Reinforcements study (completed in 2022) has led to the Mississagi x Third Line Reinforcement project, also known as the North Shore Link project (see Appendix A, T-SS-11.03), which is further described above in Section 2.0. As noted above, Recommendation 5 is as follows:

5. New double circuit 230 kV transmission line between Mississagi TS and Third Line TS, with target in-service year 2029 to 2030.

The project will develop a double circuit 230 kV transmission line between Mississagi TS and HOSSM's Third Line TS, with 230 kV switchyard expansion at both Mississagi TS and Third Line TS to accommodate the new circuits. This investment involves the station work at HOSSM's Third Line TS to enable the North Shore Link project and is included in HOSSM's capital expenditures for the 2027-2032 period.

As described in TSP 2.10, Hydro One has been operationally integrated with HOSSM since October 1, 2018. However, HOSSM remains financially and legally separate until a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One.

HOSSM continues to be the licenced owner and operator of its transmission system, however, it relies on Hydro One to carry out the day-to-day operations, pursuant to affiliate service agreements as outlined in Exhibit D-02-03. Although HOSSM is distinct and its approved revenue requirement is established separately, many processes including the asset management, planning and work execution approaches are common and integrated with Hydro One Transmission and are described within Hydro One's SPF and TSP.

Since HOSSM is operationally integrated with Hydro One, the investment need, investment description, outcomes, alternatives, as well as execution risk and mitigation, as described above for Hydro One in Sections 2.0, 3.0, 4.0, 6.0, and 7.0, respectively, are applicable to HOSSM's Third Line TS station work investment.

HOSSM considers a bulk system project to be non-discretionary in nature in either of the following circumstances: (i) where through the IESO's Bulk System Planning Process HOSSM is identified, expressly or implicitly, as the relevant transmitter to undertake a recommended transmission solution, or (ii) where following the IESO's Bulk System Planning Process a transmission solution is designated by Order in Council as a priority transmission project and HOSSM, expressly or implicitly, is identified as the relevant transmitter to undertake the priority transmission project, including where HOSSM is required by its transmission licence to develop the project.

Table C-1 below summarizes HOSSM's planned and forecast net capital expenditures for the 2022-2026 rate period and the forecast net capital expenditures for the 2027-2032 rate period.

Table C-1 - HOSSM – Investment Expenditures[25]

($M)	2027	2028	2029	2030	2031	2032	Total 27-32
Gross Capital Expenditures	18.3	29.4	9.2	0.3	0.0	0.0	57.2
Less Removals	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
Net Capital Expenditures	**18.3**	29.4	**9.2**	**0.3**	**0.0**	**0.0**	**57.2**

At the time of filing this Application, the project maturity is Planning (P), which reflects non-execution work, regardless of level of upfront development.

This investment is expected to be placed in-service in 2029 at a forecast Project Total of $64.8M. Prior to 2027, HOSSM expects to begin project development activities, including Class Environmental Assessment and procurement of long lead items for the project. HOSSM expects to incur $7.6M during this period.

[25] Figures presented in the tables may not sum to the totals shown due to rounding.

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T-SS-12	REGIONAL PLANNING
Primary Trigger:	Regional Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	216.4	250.7	252.9	237.3	170.1	1,127.4

Summary:

This non-discretionary investment is required to enable Hydro One to undertake a large portfolio of regional planning projects comprised of modifications to Hydro One owned network assets, and construction of new network assets, where Hydro One has been identified by the Independent Electricity System Operator (IESO) through the Regional Planning Process and related studies, either implicitly or explicitly, as the recommended transmitter to undertake the modifications or new construction.

The portfolio of projects included in this investment for the 2028-2032 period consists of 14 material investments arising from eight regional planning processes. These regions include Windsor-Essex, Northwest-North of Dryden, Kitchener Waterloo Cambridge Guelph, Greater Ottawa, St. Lawrence, Toronto, the Niagara Region, and GTA West.

Projects vary from station expansions and new transformer stations to new transmission lines and uprates of existing circuits. Many projects are linked to enabling load growth and maintaining reliability at the regional level.

Hydro One considers a regional planning project to be non-discretionary in nature where Hydro One is identified, expressly or implicitly, as the lead transmitter in the region and is expected and/or obligated to implement a recommended solution pursuant to its responsibilities under the Transmission System Code (TSC) or when a project is designated a priority transmission project by Order in Council (OIC) and Hydro One is required to undertake the project as a result of a Transmission Licence condition made pursuant to a Ministerial Directive.

1.0 OVERVIEW

Regional infrastructure planning with key stakeholders supports transparency and the cost-effective development of electricity infrastructure in Ontario. This is consistent with one of the guiding principles in the OEB's Renewed Regulatory Framework (RRF), which states that infrastructure planning on a regional basis, between licenced transmitters, the IESO and local distribution companies (LDC), is to be undertaken to ensure that regional issues and requirements are integrated into a utility's planning processes.

As the largest transmitter in the province, Hydro One plays a key role in the regional planning process. Hydro One Transmission is the lead transmitter in 20 of the 21 regional planning regions and is responsible for leading the development of Needs Assessments and Regional Infrastructure Plans in those regions. More details regarding Regional Planning and its coordination can be found in SPF Section 1.2.

Regional planning investments address supply and reliability issues at a regional and/or localized level, such as the supply facilities that connect and deliver power to a group of load stations in an area or region. Regional planning generally considers the 115 kV and 230 kV portions of the power system, which supply various parts of the province, but can overlap with bulk system planning and/or distribution system planning at the interface points or where there may be regional resource options or distribution solutions to address the broader local area for a specific region.

Regional planning is intended to be undertaken for each of the planning regions on a five-year cycle, the first of which began in 2013, although the process may occur more frequently depending on the emergence of new needs. Once the regional planning process is initiated by a planning trigger, the process unfolds through the following phases:

- Needs Assessment (NA);
- Scoping Assessment (SA);
- Integrated Regional Resource Plan (IRRP); and
- Regional Infrastructure Plan (RIP).

Where the regional planning recommendations are for non-wires alternatives, those recommendations feed into various IESO processes such as electricity Demand Side Management (eDSM), demand response, distributed generation, and longer-term capacity procurement plans. Where the regional planning recommendations are for wire or local solutions, those recommendations are detailed within the RIP and feed into the investment planning processes of the relevant transmitter(s) by supporting the need, scope and timing for the recommended solutions.

Based on the foregoing, Hydro One considers a regional planning project to be non-discretionary in nature where Hydro One is identified, expressly or implicitly, as the lead transmitter in the region and is expected to undertake a recommended transmission solution and/or is obligated to implement a recommended solution pursuant to its responsibilities under the TSC, or when a project is designated a priority transmission project by Order in Council (OIC) and Hydro One is required to undertake the project as a result of a Transmission Licence condition made pursuant to a Ministerial Directive.

Hydro One's participation in the Regional Planning process and its responsibilities for implementing recommended solutions arise from its obligations as a licenced transmitter to design, construct, operate and maintain its transmission system in accordance with the TSC, to maintain the reliability and integrity of its system, and to reinforce or expand its system as required to meet load growth.

Accordingly, when an IRRP and/or RIP recommends expansions or reinforcements within a targeted in-service timeline, if the recommended work involves modifications to Hydro One's existing facilities or the construction of new facilities where Hydro One has been recommended as the entity to develop, seek approvals for, and/or to build new assets, then it is incumbent upon Hydro One to implement the recommended solution. Hydro One does this by incorporating the recommended solution into its investment plans, undertaking the relevant development and scoping work, applying for and securing required approvals, procuring the necessary land rights and equipment, and putting into service the recommended facilities in a manner that delivers sustained compliance with the reliability standards and criteria underlying the established need. This includes

ensuring that final designs, protection and control schemes, and resulting operating configurations remain compliant at commissioning and throughout the asset life cycle.

For the reasons set out above, this investment in a portfolio of Regional Planning projects is non-discretionary. By virtue of the fact that Hydro One is the lead transmitter in 20 out of the 21 planning regions, it is obligated to implement most transmission solutions that are recommended through Regional Planning processes. These recommendations are driven by the need to maintain the reliability and integrity of regional electricity transmission systems in accordance with the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and IESO reliability standards and criteria, and to expand and reinforce the transmission system to meet local load growth. These recommended solutions necessitate modifications to Hydro One's existing transmission system, or the construction of new transmission facilities, which Hydro One must implement to ensure compliance with reliability standards and criteria, as well as to meet load growth, in accordance with its Transmission Licence and the TSC. Not proceeding with this portfolio of investments, or any investments within the portfolio, within the specified timelines is not an alternative as it would result in Hydro One failing to meet its obligations as a licenced Ontario transmitter, the regional transmission system failing to meet NERC, NPCC and/or IESO reliability standards and criteria, and inadequate transmission capacity to support anticipated generation growth and load growth, as well as related economic growth.

2.0 INVESTMENT NEED

This investment is driven by eight regional planning studies undertaken since 2022 that are part of the ongoing cycles of the Regional Planning process. These studies recommend the implementation of a portfolio of fourteen transmission expansion and reinforcement projects in the corresponding planning regions of Ontario.

The Regional Planning process is described in SPF Section 1.2. Regional Planning is a multi-year, cyclical process, undertaken in each of Ontario's twenty-one planning regions, where Hydro One is the lead transmitter in all but one of those regions. At the time of filing, eight of the regions have either completed third cycle planning, or are progressing through the remaining stages. Recommended transmission projects arising from these eight

regions across the NA, IRRP, or RIP are included in this investment. A full list of the recommended projects that require investments within the 2028-2032 period is set out in Appendix A.

As a licenced transmitter, Hydro One is required to maintain the reliability and integrity of its transmission system, and to reinforce or expand its transmission system as required to meet load growth. As such, where regional planning processes result in recommendations for reinforcements or expansions of Hydro One's system to meet load growth and/or to address system reliability needs, Hydro One is obligated to implement the recommended solution by including it in its investment plan. Where it is reasonably expected that regional planning processes which remain underway will likely result in specific expansion or reinforcement projects relating to Hydro One's system over the upcoming rate period, it is appropriate for Hydro One to include those projects in its investment plans so that it is able to meet those needs in the required timeframe once the relevant regional plan recommendations are finalized. Moreover, it is appropriate for Hydro One's investment plans to account for reasonably anticipated investment needs arising from regional planning processes that are undertaken during the test period. Excluding these projects from its investment plan for the period would leave these needs unmet, which would significantly delay the required transmission infrastructure, and jeopardize reliability and/or transmission adequacy to support load growth in the affected regions. Alternatively, Hydro One would need to redirect funding away from other planned priorities to undertake such non-discretionary regional planning project(s).

Table 1 summarizes the eight planning regions for which there is a completed or soon to be completed Needs Assessment, Integrated Regional Resource Plan and/or Regional Infrastructure Plan that includes recommendations for Hydro One to implement specific transmission investments during the 2028-2032 period. The fourteen specific recommended investments arising from these Regional Planning Studies are described in Table 1 below.

1 **Table 1 - Summary of Regional Planning Studies and Recommendations**

Regional Planning Study	Hydro One Project	ISD Ref.
1. Windsor-Essex IRRP & RIP (2025)	Station expansion at Lauzon TS and Lakeshore TS to accommodate the new 230 kV Windsor Lakeshore Power Line.	T-SS-12.01
2. Northwest - North of Dryden IRRP Addendum (2025)	Station expansion at Dryden TS and Ear Falls TS to accommodate two double-circuit 230 kV circuits, one from Dryden TS to Ear Falls TS, and one from Ear Falls to Red Lake CSS. Install new autotransformers, capacitor installations, and associated transmission upgrades. (Red Lake Transmission Project)	T-SS-12.02
3. KWCG IRRP (2026)	Construct a new 500/230 kV autotransformer station, Wellington TS, and station expansion at Preston TS to accommodate the new double-circuit 230 kV Waterloo Wellington Power Line.	T-SS-12.03
	Uprate existing 115 kV circuits B5C/B6C, D7F/D9F and F11C/F12C using higher ampacity conductors.	T-SS-12.04
	Uprate D6V/D7V 230 kV circuits and undertake Detweiler TS reconfiguration to support customer load growth.	T-SS-12.05
4. Greater Ottawa IRRP & RIP (2025/2026)	Kanata Area Transmission Reinforcement, including Re-purpose existing new 230 kV line from Merivale TS to South March TS, new switching station, and reinforcement of supply to Nepean TS.	T-SS-12.06
	Provide second 230 kV supply to Orleans TS including transformer and switching facility upgrades.	T-SS-12.07
	Install new 115 kV breaker at Merivale TS to separate M1R and L2M circuits.	T-SS-12.08
5. St. Lawrence Needs Assessment (2026)	Install two new 21.6 MVar capacitor banks at Brockville TS for voltage support.	T-SS-12.09
6. Toronto IRRP & RIP (2025/2026)	Upgrade 115 kV circuits between Manby TS and Riverside Junction to increase transmission capacity.	T-SS-12.10
7. Niagara Regional Planning (Ongoing)	Upgrade four 230 kV circuits between Beck GS and Abitibi Junction (approximately 14 km) using higher-capacity conductors.	T-SS-12.11
	Upgrade 115 kV circuits between Decew Falls TS and Glendale (approximately 10 km) using higher-capacity conductors.	T-SS-12.12
8. GTA West IRRP (Ongoing)	Construct a new 230 kV double circuit line (approximately 10 km) between Meadowvale TS and Hurontario SS.	T-SS-12.13
	Reconfiguration of Hurontario SS to enable Milton TS development.	T-SS-12.14

Windsor-Essex Regional Planning – IRRP and RIP (2025)

The third cycle Windsor-Essex IRRP and RIP, completed in 2025, focused on significant growth in electricity demand driven by greenhouse agriculture, industrial development, and major manufacturing investments in the Windsor area. The study assessed needs across the West Essex/Windsor, Kingsville-Leamington, and Lakeshore/Tilbury subsystems, while also examining the long-term ability of the regional transmission network to supply growing demand. A map of recommendations from the Windsor-Essex regional planning is shown in Figure 1.

Recommendations from the third cycle of regional planning that require System Service investments within the 2028-2032 period include:

1. Build a new double-circuit 230-kV transmission line between Lauzon TS and Lakeshore TS, along with supporting station upgrades to ensure long-term reliability and support continued economic growth, with a targeted in-service of 2032.

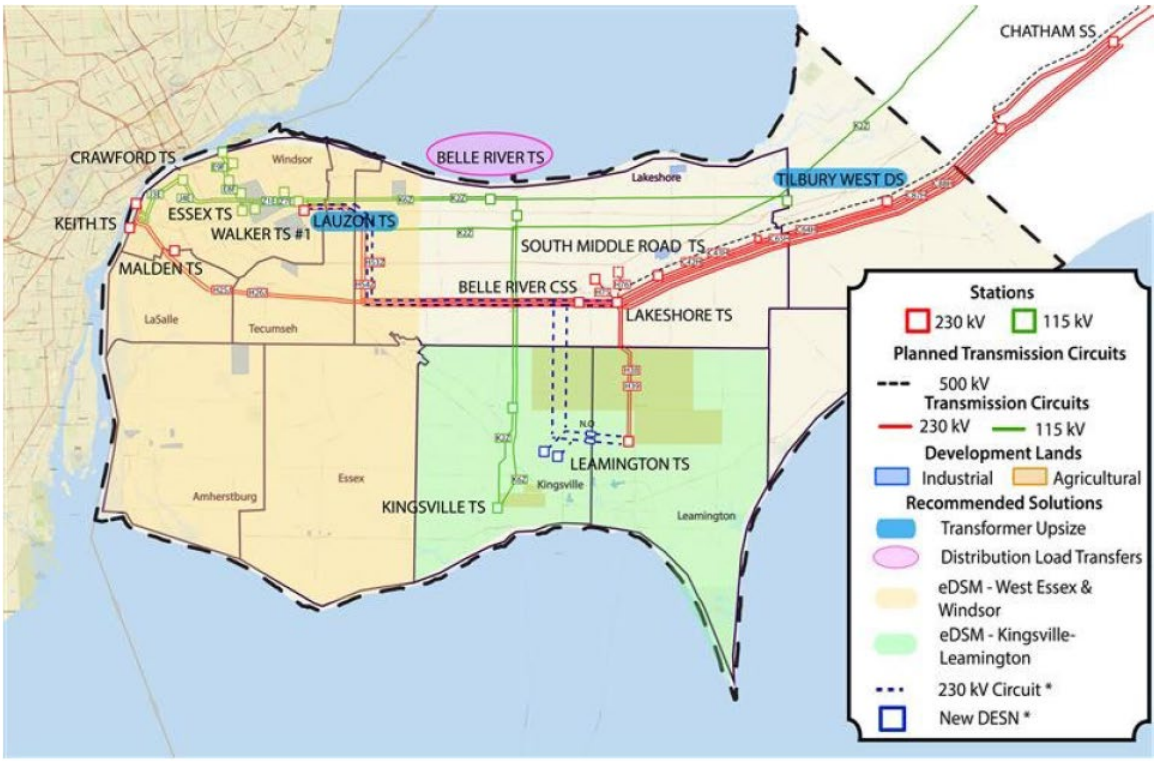

Figure 1: Map of Recommendations from Windsor – Essex Regional Planning

Recommendation 1 has led to the Windsor Lakeshore Transmission Line Project (see Appendix A, T-SS-12.01), which will involve the construction of a double circuit 230 kV line between Hydro One's Lauzon TS located in Windsor, and Lakeshore TS located in Lakeshore, with necessary station upgrades to accommodate the two new circuits.

This project is also the subject of OIC 875/2022, which directed the OEB to amend Hydro One's transmission licence to require Hydro One to develop the project in accordance with the scope and timing recommended by the IESO. The line portions of the project will be owned and included in the rate base of a separate Affiliated Transmission Partnership (ATP) and the corresponding expenditures are therefore excluded from this rate application.

Northwest – North of Dryden Region – IRRP Addendum (2025)

The North of Dryden IRRP Addendum, led by the IESO, builds on and supplements the second cycle Northwest IRRP completed in 2023. The Addendum was developed in response to forecasts of rapid growth associated with mining and critical mineral development in northwestern Ontario. The study focused on electricity supply needs in the Red Lake, Pickle Lake and Ear Falls areas, and examined the ability of the existing transmission system to support both the current load level and future large industrial loads. Recommendations from the Addendum that require System Service investments within the 2028-2032 period are:

2. Build a new double circuit 230 kV transmission line from Hydro One owned Dryden TS to Ear Falls TS (approximately 100 km), and on to Red Lake CSS (approximately 65 km), with two new 230/115 kV autotransformers at Ear Falls TS, two new 230/115 kV autotransformers at Red Lake SS.
3. Install 40MVar shunt capacitors at Red Lake CSS, Ear Falls TS, and 230 kV bus of Pickle Lake TS.
4. Reconfiguration of existing 115 kV circuits E4D and E2R to operate normally open.

Recommendations 2, 3 and 4 have led to development of the North of Dryden Transmission Reinforcement or "Red Lake Transmission Project" (see Appendix A, T-SS-12.02) with a targeted in-service date between 2028 and 2030, however the IESO has

deferred to Hydro One to determine the most practical and achievable in-service date. The project will involve the construction of a new double circuit 230 kV transmission line from Dryden TS to Ear Falls TS, and a new double-circuit 230 kV transmission line from Ear Falls TS to a neighboring transmitter's switching station (Red Lake CSS), with associated station upgrades at Dryden TS, Ear Falls TS and Pickle Lake TS to accommodate the new circuits and new equipment in accordance with IESO study recommendations. The project has an expected in-service date of 2031.

This project is also the subject of OIC 369/2026 and OIC 370/2026, which deemed this project to be a priority transmission project, and directed the OEB to amend Hydro One's transmission licence to require Hydro One to proceed with development of the project.

The line portions of the project will be owned and included in the rate base of an ATP, and the corresponding expenditures are therefore excluded from this rate application. Scope related to Red Lake CSS will be the responsibility of Wataynikaneyap Power and is excluded from this application.

Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region - IRRP (2026)

The KWCG IRRP was developed to address rapid population growth, continued expansion of the technology sector, electrification initiatives, increasing electricity consumption from commercial and industrial growth, and several new large developments related to data centres in the KWCG region. A map of recommendations from the KWCG regional planning is shown in Figure 2. Recommendations from the KWCG IRRP that require System Service investments by Hydro One within the 2028-2032 period include:

5. Construct a new 500/230 kV autotransformer station in the Puslinch area, with a double-circuit 230 kV transmission line connecting it with Preston TS, with a targeted in-service of 2031 or earlier (Waterloo Wellington Power Line).

6. Uprate three existing Hydro One owned 115 kV circuits (B5C/B6C, D7F/D9F and F11C/F12C), with a targeted in-service of 2028.

7. Uprate sections of Hydro One owned D6V and D7V 230 kV circuits from Detweiler TS to a new Customer Transformer Station, and conduct station reconfiguration work at Detweiler TS to mitigate the adverse impact of the existing static VAR compensator operating instructions, with a targeted in-service of 2029.

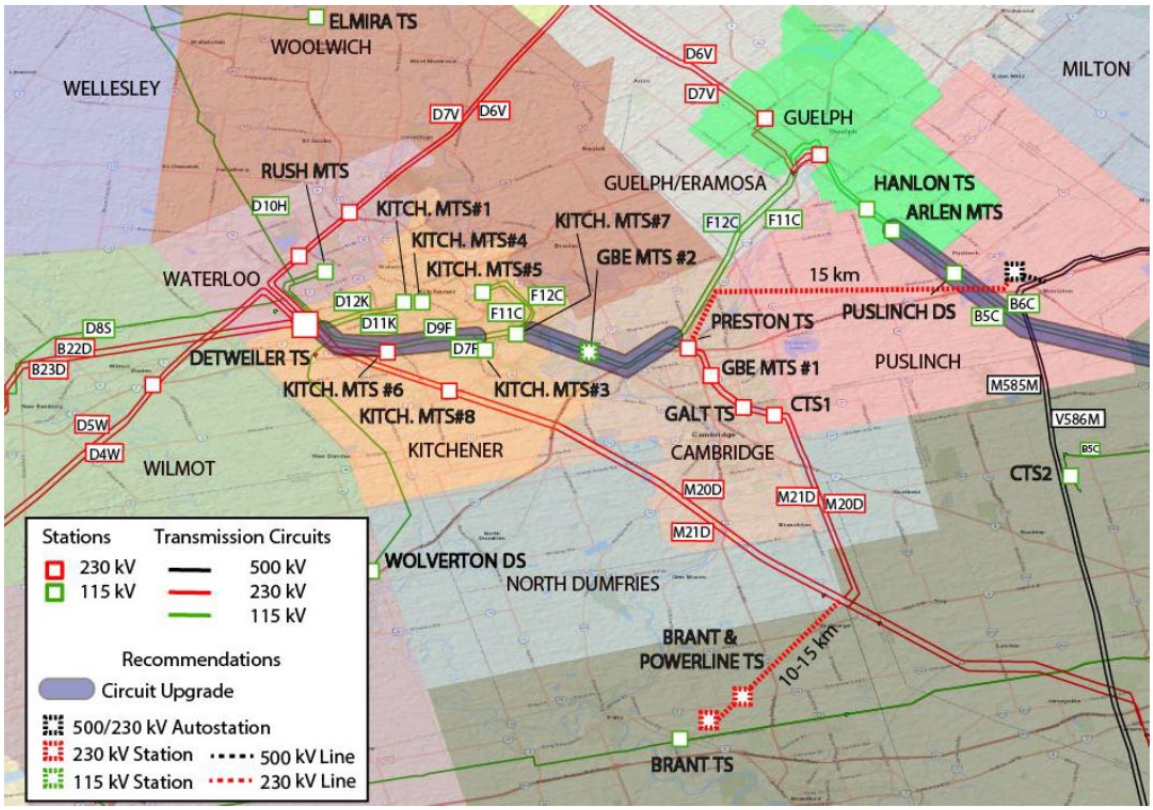

Figure 2: Map of Recommendations from KWCG Regional Planning

Due to the urgent need, the IESO has, pursuant to its authority under the *Electricity Act*, the Market Rules and its licence, issued an Urgent Letter to Hydro One and GrandBridge Energy on September 30, 2025, to notify the transmitter and distributor of near-term work required within the next five years, in advance of the publication of the IRRP. The letter recommends that Hydro One proceed immediately with recommendations 5 and 6. Recommendation 7 is not part of IESO's Urgent Letter.

Recommendation 5 from the Urgent Letter has led to the development of a new 500/230 kV autotransformer station, also known as the Wellington TS Project (see Appendix A, T-

SS-12.03). The station will be equipped with two 500/230 kV autotransformers, associated 500 kV and 230 kV station equipment and infrastructure and will sectionalize the existing 500 kV lines between Middleport TS and Milton TS. The station will also accommodate a new double circuit 230 kV line from Wellington TS to Preston TS, for approximately 15km, also known as the Waterloo Wellington Power Line project. The line portions of the project will be owned and included in the rate base of an ATP, and the corresponding expenditures are therefore excluded from this rate application.

Recommendation 6 from the Urgent Letter has led to circuit upgrade work on B5C/B6C, D7F/D9F and F11C/F12C, with higher ampacity conductors (see Appendix A, T-SS-12.04). This line upgrade work is not expected to meet Hydro One's ATP threshold.

Recommendation 7 has led to circuit upgrade work on D6V and D7V, as well as Detweiler TS station reconfiguration work. The line upgrade is estimated to be approximately the first 10km out of Detweiler TS to a new customer transformer station (see Appendix A, T-SS-12.05). The actual length of the line upgrade will be determined based on the connection point at the new customer transformer station.

Greater Ottawa Region - IRRP and RIP (2025/2026)

The Greater Ottawa Region IRRP and RIP examine electricity needs and wire options arising from continued residential, commercial, and institutional growth across the City of Ottawa, particularly in areas such as Kanata-Stittsville and the city's eastern, western, and southern growth corridors. The study assessed station capacity, transmission capability, and the impacts of increasing electrification. Recommendations from the Greater Ottawa Region RIP that require System Service investments by Hydro One within the 2028-2032 period include:

8. Construct a coordinated set of new infrastructure with a targeted in-service timeline of 2033, which includes:
    a. a new 230 kV single circuit from Merivale TS to a new 230 kV switching station that will extend to the proposed Kanata North MTS. This new line will also serve as a second supply to Nepean TS; and

b. a new switching station that interconnects existing and new 230 kV stations to improve system resiliency and flexibility.

A diagram that illustrates this recommendation is shown in Figure 3 below.

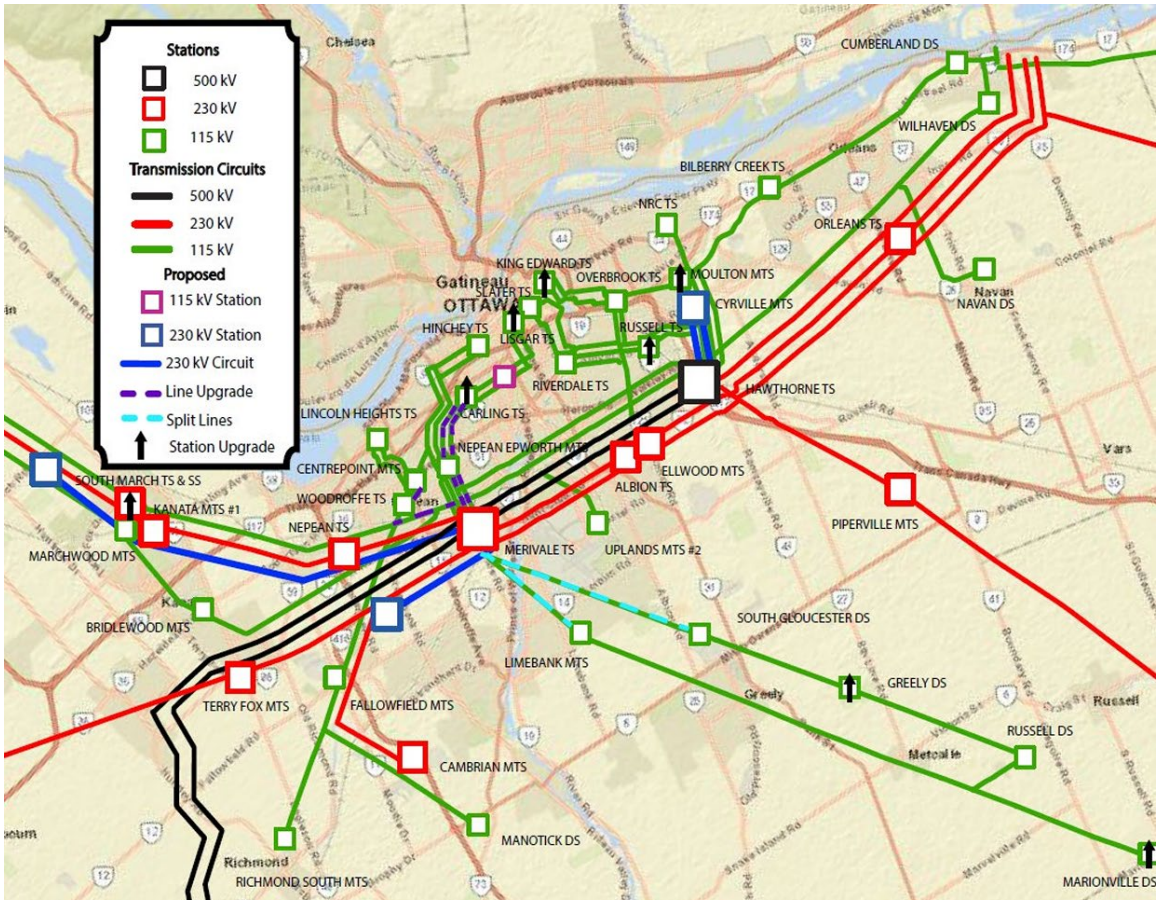

Figure 3: Proposed new 230 kV infrastructure

9. Coordinate the retirement of Bilberry Creek TS by performing station upgrade work at Orleans TS to upgrade it from dual supply 230/27.6 kV and 115/27.6 kV to 230/27.6 kV DESN, and construct a new 230 kV supply circuit, for approximately 11km, towards the upgraded Orleans TS from Hawthorn TS, with a targeted in-service timeline of 2029.

10. Install a new breaker at Merivale TS to separate L2M and M1R, with a targeted in-service timeline of 2032.

Recommendation 8 has led to the development of the Kanata Area Transmission Reinforcement Project (see Appendix A, T-SS-12.06), which involves construction of a new 230 kV single circuit from Merivale TS to a new switching station by re-purposing existing circuits between Merivale TS and South March TS, for a total of approximately 15km. The line projects in recommendation 8 are not expected to meet Hydro One's ATP inclusion criteria as the line work involves re-purposing an existing Hydro One owned line, and is therefore included in this Application. A new 230 kV switching station that accommodates three 230 kV line terminations will be built near South March TS. Necessary station upgrades at Merivale TS and Nepean TS will be included to accommodate the new line connection. The line extension from the new switching station to the proposed Kanata North MTS, for approximately 3km, would be a customer funded System Access project (see T-SA-11, below materiality). Construction of the new Kanata North MTS is expected to be performed by the LDC customer.

Recommendation 9 has led to the development of a project to provide a second 230 kV supply to Orleans TS, where necessary station upgrades, including new 230 kV switching facilities and a new 230 kV Transformer, will be constructed (see Appendix A, T-SS-12.07).

Recommendation 10 has led to the development of a project to install a new 115 kV breaker at Merivale TS to separate circuits M1R and L2M into two independent 115 kV circuits (see Appendix A, T-SS-12.08).

St. Lawrence Region - Needs Assessment (2026)

The St. Lawrence regional planning process started in Q1 2026 with the Needs Assessment phase to identify system needs in the St. Lawrence region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase, and b) require further assessment and regional coordination. The NA concluded on March 30, 2026, and included recommendations for Hydro One to implement the following System Service investment within the 2028-2032 period:

11. Install new 44 kV capacitor banks at Brockville TS to ensure voltage remains within allowable thresholds and compliant with the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and TSC switching requirements at the station. The NA recommends that this need does not require further regional coordination in the IRRP phase, and can proceed directly by Hydro One, with a targeted in-service year of 2030.

Recommendation 11 has led to the development of a project to install two new capacitor banks at Brockville TS's 44 kV bus, each at 21.6 MVar, with necessary switching facilities and protection for their connection to Brockville TS (see Appendix A, T-SS-12.09).

The St. Lawrence region is currently undergoing its IRRP phase, led by the IESO, to determine the need for any additional recommendations to address other needs identified in the 2026 NA, where broader regional coordination is required. The IRRP phase is expected to be completed by Q2 2027.

Toronto Region - IRRP and RIP (2025/2026)

The Toronto Region IRRP was completed in October 2025, with the RIP completed in May 2026. Together, they address electricity needs within the municipal boundaries of the City of Toronto, driven by substantial population growth, urban intensification, electrification, and climate-related impacts across Northern, Western, Eastern, and Downtown Toronto, while maintaining system reliability and resiliency.

The plan recommends several major investments, some of which are integrated into the South and Central Region Bulk Planning Studies. The IRRP also recommends transmission reinforcements that are more local to the Toronto region, transformer station expansions, enhanced demand-side management programs, and increased deployment of distributed energy resources. A recommendation for the Toronto Region that requires System Service investment by Hydro One within the 2028-2032 period is:

12. Increase transmission capacity by upgrading circuits from Manby TS to Riverside Junction, with a targeted in-service year of 2028.

Recommendation 12 has led to the development of a 115 kV circuit upgrade project between Manby TS and Riverside Junction, for approximately 7km, with higher rated conductor (see Appendix A, T-SS-12.10).

Niagara Region - Third Cycle Regional Planning (ongoing 2026/2027)

The third cycle Niagara regional planning process started in Q3 2026 with the Needs Assessment phase to identify the transmission investments required to ensure reliable electricity supply for the Niagara Region over the near and long term, while supporting population growth, economic development, industrial expansion, and electrification initiatives. Niagara Region is currently undergoing the third cycle Scoping Assessment phase, led by the IESO, and is expected to commence the IRRP phase in 2027.

In recognition of the ongoing nature of Regional Planning, this investment portfolio includes forecast expenditures that Hydro One expects to be recommended for the Niagara Region based on emerging constraints in the region. This anticipated work is not expected to be owned or included in the rate base of an ATP or other third-parties, and will be undertaken in accordance with future recommendations made by the IESO, through the Regional Planning process, for investments identified as being required to be in-serviced by Hydro One over the 2028-2032 period. Hydro One anticipates that the Niagara Regional Planning process will require System Service investments by Hydro One within the 2028-2032 period including:

13. Increase transmission capacity by upgrading four 230 kV circuits between Beck GS and Abitibi Junction, for approximately 14km, with a targeted in-service year of 2029.

14. Increase transmission capacity by upgrading 115 kV circuits from Decew Falls TS to Glendale, for approximately 10km, with a targeted in-service year of 2030.

Item 13 is expected to provide the basis for a 230 kV circuit corridor upgrade project between Beck #2 TS and Abitibi Junction, for approximately 56 circuit-km, with higher rated conductor (see Appendix A, T-SS-12.11).

Item 14 is expected to provide the basis for an 115 kV circuit upgrade project from Decew Falls TS to Glendale TS, for approximately 10km, with higher rated conductor (see Appendix A, T-SS-12.12).

GTA West Region - IRRP – Third Cycle Regional Planning (ongoing 2026/2027)

The GTA West IRRP identifies the transmission investments required to ensure reliable electricity supply for the GTA West Region over the long term, while supporting population growth, economic development, industrial expansion, and electrification initiatives. GTA West Region is currently undergoing its third cycle IRRP phase.

In recognition of the ongoing nature of Regional Planning, this investment portfolio includes forecast expenditures that Hydro One expects to be recommended for the GTA West Region based on emerging constraints in the region. This anticipated work is not expected to be owned or included in the rate base of an ATP or other third-parties, and will be undertaken in accordance with future recommendations made by the IESO, through the Regional Planning process, for investments identified as being required to be in-serviced by Hydro One over the 2028-2032 period. Notably, in the South and Central Bulk Plan published in August 2026, the IESO identified additional downstream regional transmission infrastructure to be finalized and recommended through the GTA West Region IRRP. Hydro One therefore anticipates that the GTA West Regional Planning process will require System Service investments by Hydro One within the 2028-2032 period that will include:

15. New Meadowvale to Hurontario Transmission line to complement the development of Milton TS and provide additional supply capacity to GTA West/Halton and Peel Region.

16. Hurontario Switching Station reconfiguration to enable the development of Milton TS and provide additional supply capacity to GTA West/Halton and Peel Region.

Item 15 has led to the investment to develop a new 230 kV double circuit line from the existing Hurontario Switching Station (SS) to Meadowvale TS (see Appendix A, T-SS-12.13), for approximately 10km. The line project is not expected to meet Hydro One's ATP inclusion threshold and is therefore included in this Application.

Item 16 has led to the investment to reconfigure Hurontario SS (see Appendix A, T-SS-12.14).

Unallocated Regional Planning Amounts

During the 2028 to 2032 rate period, 10 out of Ontario's 21 electrical regions will undergo their third cycles of regional planning, based upon which Hydro One anticipates that additional transmission regional plan investments may be triggered. The resulting recommendations will not be finalized until the conclusion of those cycles. Hydro One is obligated to meet these recommendations as they are finalized by developing them into executable projects; however, the need for and scope of these projects has not yet been determined.

Accordingly, Hydro One has forecast a conservative estimate for unallocated amounts to fund projects identified through regional planning processes during the rate period (see Appendix A, T-SS-12.15). These project needs and scopes have not yet been identified. Local Area Supply projects are identified during regional planning and address local transmission needs within an area or region. Each project will be initiated based on a recommendation made within an IRRP and/or RIP.

The unallocated amount, as presented in Table B1 of Appendix B, is budgeted to address capital expenditures amounting to $150M for projects for which the scope has not yet been determined. This amount reflects the extent to which actual and forecast regional planning 2023-2027 expenditures exceed the amount reflected in the 2023-2027 settlement plan, which is approximately $157M. Based on average forecasted costs of identified regional planning related projects over the 2028-2032 period, this is a conservative estimate in light of the increased demand as seen with the number of customer connections. As Hydro One expects greater project certainty in the near term (2028-2030), the net amounts in 2028 and 2029 are reduced to reflect a lower risk of near-term unknowns. Longer-term (2030-2032) expenditures are forecasted to rise to account for the unprecedented system expansions that Ontario's electrical infrastructure is expected to experience. This investment will fund projects proposed in response to specific needs identified during the regional planning process; alternatives (if any) will be reviewed as part of this planning process.

3.0 INVESTMENT DESCRIPTION

This investment will support projects that consist of regional expansion or reinforcement recommended through regional planning processes in different regions across Ontario. Typically, the nature of the work involves modifications to or expansions of existing Hydro One stations, or transmission line upgrades. For certain projects, new stations or lines need to be designed and constructed based on the regional planning recommendations. Where applicable, projects also include all necessary protection and control modifications as required to integrate new station components. A list of projects with summaries of their scope, project stage and the triggering regional plan, including flags identifying those projects arising from incomplete regional planning processes, is provided in Appendix A.

The need and timeline for each project is established through system studies, such as lead transmitter NAs, RIPs, or IESO IRRPs, utilizing the demand forecast for the respective region. The scope of each project is tailored to address the needs of the specific region and each varies in scope and complexity. System Impact Assessments (SIA) and Customer Impact Assessments (CIA) will be conducted at the individual project level to confirm that each project will not adversely affect the reliability of the grid. Depending on individual project scope, environmental assessment, First Nation consultation and community engagement activities, in line with standard Hydro One project execution practices and applicable legal requirements, may be undertaken at a project level to identify and mitigate impacts.

4.0 OUTCOMES

4.1 OEB RRF OUTCOMES

Table 2 presents anticipated benefits as a result of the Investment in accordance with the OEB's Renewed Regulatory Framework (RRF).

Table 2 - Outcome Summary

Customer Focus	• Maintain reliable power delivery at the regional level
Operational Effectiveness	• Improve operational effectiveness and load serving capability at the regional level
Public Policy Responsiveness	• Ensure compliance with applicable regulatory requirements and respond to provincial policy initiatives

5.0 EXPENDITURE PLAN

Table 3 summarizes Hydro One's forecast capital expenditures on regional planning projects under this investment for the 2028-2032 rate period.

Table 3 - Hydro One – Investment Expenditures[1,2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	219.1	258.3	273.2	256.9	189.3	1,196.7
Less Removals	0.6	0.4	0.1	0.1	0.1	1.2
Less Capital Contributions	2.1	7.2	20.2	19.6	19.1	68.1
Net Capital Expenditures	**216.4**	**250.7**	**252.9**	**237.3**	**170.1**	**1,127.4**

Given the long lead-time for, and complex nature of these regional planning projects, the forecasted capital expenditures for projects included in this investment have been developed by Hydro One based on analysis of historical costs for completed or recently estimated projects that have similar project scopes, applying relevant Hydro One subject matter expertise for reasonable adjustments to reflect global market conditions, including impacts from inflation on material and equipment prices and labour costs. These investments are complex and are undertaken over several years in accordance with the

[1] Figures presented in the tables may not sum to the totals shown due to rounding.
[2] Forecast net capital expenditures for the 2028-2032 period include $32.0M of immaterial projects.

Capital Project Delivery Model discussed in TSP Section 2.11. At the time of filing this Application, most projects are in the Planning and Definition phase, during which the scope, design and execution plans are being further defined. Cost and schedule accuracy are therefore expected to improve as the individual projects progress.

Given the regional nature of these projects, costs are recoverable through incremental revenue from the appropriate rate pool and customer capital contributions under the Connection and Cost Recovery Agreement (CCRA), where applicable. Customer capital contributions under the CCRA may not be required when project costs are fully recovered through incremental revenue. The investment costs are forecasted based on best available information and historical costs as noted above. Capital contribution amounts are estimated pursuant to Hydro One's Transmission Connection Procedure in accordance with the TSC. Project costs and capital contribution amounts are subject to true-up once the project is placed in-service, subject to the terms of a CCRA. CCRAs allow Hydro One to recover the actual costs incurred even if a customer elects to cancel a project.

As proposed in Exhibit G-01-03 Section 3.1, the Externally Driven Transmission Projects Variance Account will be used to record the revenue requirement impact of variances between the in-service additions embedded in Hydro One's approved revenue requirement relating to this investment and the actual in-service additions for this investment over the 2028-2032 period.

6.0 ALTERNATIVES

ALTERNATIVE 1: STATUS QUO

This alternative is rejected because Hydro One, as a licenced transmitter, is obligated to implement transmission investments where recommended through the Regional Planning Process. Maintaining status quo by not responding to the recommendations will not address future electricity needs, and will cause Hydro One to fall out of compliance with its obligations to comply with its transmission licence and the TSC by failing to expand and reinforce its transmission system to meet anticipated load growth. Moreover, doing nothing would result in inadequate transmission capacity in various regions of Ontario.

ALTERNATIVE 2: PROCEED WITH IESO RECOMMENDATIONS ONLY WHEN DIRECTED UNDER AN OIC, MINISTERIAL DIRECTIVE OR SIMILAR INSTRUMENT

This alternative is rejected as each recommendation made through regional planning is required to address defined regional needs with targeted timelines, where options for addressing identified needs (including non-wires options) have been thoroughly analyzed by the IESO, in consultation with participating stakeholders, and where the IESO has then concluded that each recommended solution achieves the best cost-benefit for the identified need that the solution will address. It is not prudent to proceed with IESO recommendations only when Hydro One is formally directed by means of an OIC, Ministerial Directive, or governmental instrument of a similar nature, as it would introduce unnecessary delay for the needed regional electricity infrastructure as recommended by IESO, and would effectively require such a governmental instrument to be issued to compel action for every single recommendation arising from the regional planning process, which is impractical, inefficient and inconsistent with historical practice in Ontario. Such inaction would put the reliability and supply adequacy of various regions' transmission adequacy at risk as the provincial load levels continue to rise, and ultimately delay various new load and generation connections, broader electrification, and economic growth in the province.

ALTERNATIVE 3: PROCEED WITH REGIONAL PLANNING RECOMMENDATIONS (RECOMMENDED)

This alternative supports multiple regional plans, for which the options analysis, needs and associated system benefits have already been evaluated through their respective regional planning processes. This alternative reinforces the existing transmission system to meet regional load growth projections, improve system resiliency, enable new load and generation connections across the province, and allows Hydro One to continue to comply with its licence obligations and TSC requirements.

This recommendation ensures that Hydro One remains responsive to regional needs, ensuring supply adequacy and reliability is maintained as provincial demand continues to rise. With typical transmission project timelines ranging from three to five years, depending on complexity, proceeding with regional planning recommendations provides the best

opportunity to meet established need dates to enable customer connections and maintain local system resiliency and reliability.

7.0 EXECUTION RISK AND MITIGATION

As described in TSP Section 2.11, Hydro One follows a Transmission Capital Project Delivery Model, throughout which project risks are identified and mitigation plans are implemented. Risks that can impact the completion of transmission line work and/or transmission station modifications/expansion projects include:

- Outage constraints: Planned outages are required to replace assets and may involve individual assets, sections of a station, or the entire station. Hydro One plans and coordinates outages to minimize impacts on customers while providing construction and commissioning staff with the access required to complete the work.
- Resource constraints: Projects in the same geographical location may require the same construction and commissioning resources. Hydro One coordinates project schedules and resource requirements to manage competing demands for these resources.
- Construction execution challenges: Existing station equipment may require retrofits to accommodate new assets because station designs and equipment standards have evolved. Significant design and construction may also be required where assets cannot be replaced in the same physical location due to space constraints, outage requirements or safety considerations.
- Real estate requirements: Station expansion and new land may be required when assets cannot be replaced in the same physical location.
- Environmental Assessment, First Nations consultation, and community engagement: New land requirements can trigger requirements for environmental assessment, First Nations consultation, and community engagement activities which may influence project timelines. Hydro One addresses these considerations through early engagement and consultation planning to support meaningful participation, and where applicable, co-develop a community engagement plan offering community benefits frameworks for employment pathways and contracting opportunities.

- Procurement challenges: Equipment procurement lead times can be long. Hydro One engages vendors at appropriate times in the planning process to ensure sufficient lead time to obtain major equipment.
- Regulatory challenges: Certain new transmission line or upgrade projects will require leave to construct applications and approvals. Hydro One prepares the necessary filing documents with sufficient engineering and cost details, informed by detailed estimates, to fulfill its regulatory obligations related to Section 92 of the *Ontario Energy Board Act, 1998*.

APPENDIX A – DESCRIPTION OF FORECAST INVESTMENTS

This Appendix describes each material investment and forecast capital expenditures for the 2028-2032 period.

ISD Ref.	Investment Name	Scope Summary	Originating Regional plans	Forecast Upgrade /Installed Units					Total 2028-2032	Project Total
				Voltage level (kV)	Trfr	Bkr	Reactive Support	Cct (km)		
T-SS-12.01	Windsor Lakeshore Transmission Line – Station Work	Station expansion at Lauzon TS and Lakeshore TS to accommodate 2 new circuits. Prior to 2028, this project is expected to begin project definition phase as per TSP 2.11.	Windsor Essex IRRP and RIP (2025)	230	-	4	-	-	65.0	70.0
T-SS-12.02	North of Dryden Transmission Reinforcement (Red Lake Transmission Project) – Station Work	Dryden TS: Install two 230 kV circuit terminations to accept new transmission line from Ear falls. Ear Fall TS: install four new 230 kV circuit terminations to accept new Transmission line from Dryden TS and Red Lake CSS; 2 new autotransformer. Install 40 MVar shunt capacitor at Ear Falls, Pickle Lake. Prior to 2028, this project is expected to begin project definition phase.	North of Dryden IRRP Addendum (2025)	230 & 115	2	12	1	-	104.4	120.0
T-SS-12.03	Wellington TS: Build new 500 kV/230 kV Station	Build a new 500/230 kV auto-transformer station to sectionalize existing 500 kV lines between Middleport TS and Milton TS.	KWCG IRRP (2026)	500 &230	2	22	2	-	223.0	264.6

ISD Ref.	Investment Name	Scope Summary	Originating Regional plans	Forecast Upgrade /Installed Units					Total 2028-2032	Project Total
				Voltage level (kV)	Trfr	Bkr	Reactive Support	Cct (km)		
		Prior to 2028, this project is expected to complete project definition and scoping phase.								
T-SS-12.04	115 kV Upgrades (B5/6C, D7/9F, F11/12C)	Uprate 3 different existing 115 kV circuit sections to achieve higher rating per IESO recommendation. Prior to 2028, this project is expected to complete project definition and scoping phase as per TSP 2.11. Project execution is also expected to commence in Q1 2027.	KWCG IRRP (2026)	115	-	-	-	49	20.8	51.4
T-SS-12.05	D6V/D7V - Upgrade circuits out of Detweiler	Uprate approximately 10km of D6V & D7V to higher capacity per IESO recommendation. Prior to 2028, this project is expected to begin project definition phase.	KWCG IRRP (2026)	230	-	1	-	10	12.7	14.6
T-SS-12.06	Kanata Area Transmission Reinforcement	Re-purpose existing new 230 kV line from Merivale TS to South March TS. Build a new 230 kV switching station to interconnect with existing C3S, M32S, and the new circuit with reactive support. Prior to 2028, this project is expected to begin project definition phase.	Greater Ottawa IRRP and RIP (2025/2026)	230	-	7	1	15	212.2	244.3
T-SS-12.07	Orleans TS: Provide second 230 kV supply	Build a new 230 kV circuit between Hawthorne TS and Orleans TS and Upgrade Orleans TS to 230 kV/27.6 kV DESN station.	Greater Ottawa IRRP and RIP (2025/2026)	230	1	2	-	11	52.9	115.6

ISD Ref.	Investment Name	Scope Summary	Originating Regional plans	Forecast Upgrade /Installed Units					Total 2028-2032	Project Total
				Voltage level (kV)	Trfr	Bkr	Reactive Support	Cct (km)		
		Prior to 2028, this project is expected to complete project definition and scoping phase with long lead time material purchased. Project execution started in Q3 2026								
T-SS-12.08	Merivale TS Split M1R-L2M	Install new 115 kV breaker at Merivale TS to separate circuit M1R and L2M into two independent 115 kV circuit. Prior to 2028, this project is expected to begin project definition phase.	Greater Ottawa IRRP and RIP (2025/2026)	115	-	1	-	-	39.3	39.3
T-SS-12.09	Brockville TS - Install new Capacitor Bank	Install two 44 kV shunt capacitor banks, 21.6 Mvar each, with associated switching devices. Prior to 2028, this project is expected to begin project definition phase.	St Lawrence Needs Assessment (2026)	230	-	-	2		8.3	9.3
T-SS-12.10	Manby x Riverside Junction 115 kV Line Upgrade	Uprate approximately 7km of K13J and K14J between Manby to Riverside Jct to higher ratings per IESO recommendation	Toronto IRRP and RIP (2025/2026)	115	-	-	-	7	14.7	23.2
T-SS-12.11	Uprate 230 kV QFW Circuits – Beck x Abitibi Junction	Uprate 4 existing 230 kV circuits between Beck #2 TS to Abitibi Jct to higher ratings. Prior to 2028, this project is expected to begin project definition phase.	Niagara Regional Planning (ongoing)	230	-		-	56	57.1	59.8
T-SS-12.12	Uprate 115 kV D9HS/D10S	Expected to uprate 115 kV D9HS D10S per IESO recommendation.	Niagara Regional Planning (ongoing)	115	-	-	-	10	20.6	21.7

ISD Ref.	Investment Name	Scope Summary	Originating Regional plans	Forecast Upgrade /Installed Units					Total 2028-2032	Project Total
				Voltage level (kV)	Trfr	Bkr	Reactive Support	Cct (km)		
		Prior to 2028, this project is expected to begin project definition phase.								
T-SS-12.13	Meadowvale to Hurontario Transmission Line	Construct new double circuit 230 kV line from Meadowvale TS to Hurontario SS for approximately 10 km in existing transmission corridor; station expansion in Meadowvale TS to accommodate new circuits. Prior to 2028, this project is expected to begin project definition phase.	GTA West IRRP (ongoing)	230	-	2	-	9	87.0	100.0
T-SS-12.14	Hurontario SS Reconfiguration - Station	Station expansion and re-termination of existing circuits into Hurontario to enable Milton TS development and accommodate new circuits from Meadowvale TS. Prior to 2028, this project is expected to begin project definition phase.	GTA West IRRP (ongoing)	230	-	2	-	-	36.0	40.0
T-SS-12.15	Unallocated expenditures	Unallocated amount to account for upcoming recommendations from ongoing regional planning		-	-	-	-	-	-	-
	Totals			-	**5**	**53**	**6**	**187**	**-**	**-**

APPENDIX B – SUMMARY OF INVESTMENT COSTS AND VARIANCES

This Appendix provides capital expenditures for material investments in the 2028-2032 rate period, and for those investments with planned or actual material capital expenditures in the 2023-2027 rate period that have material variances relative to Hydro One's forecast capital expenditures and in-service additions as revised to implement the OEB-approved Settlement Proposal in EB-2021-0110 (Plan) as described in TSP Section 2.9, if applicable.

The investments proposed in this ISD are complex and are undertaken over several years according to the Capital Project Delivery Model discussed in TSP Section 2.11. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves. The table below summarizes the capital expenditures for each investment and presents the maturity of the project, the in-service year and the project total estimates for the 2023-2027 and 2028-2032 rate periods. Project maturity is defined by the following project phases:

- Execution (E), which reflects fully approved project work;
- Planning and Definition (P), which reflects non-execution work, regardless of level of upfront development; and
- Complete (C), which reflects that the project has been placed in service

At Hydro One, projects are governed with a focus on adherence to the total project budget. In year amounts are managed on a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in the table below in reference to project total variances and overall project schedule variances.

The following investments had planned and actual capital expenditures during the 2023-2027 period but were expected to be placed in service outside of that period and so had no planned or actual in-service additions:

- T-SS-12.05 - D6V/D7V - Upgrade circuits out of Detweiler;
- T-SS-12.06 - Kanata Area Transmission Reinforcement;

- T-SS-12.07 - Orleans TS: Provide second 230 kV supply; and

In the 2028-2032 period, Hydro One expects total project costs for the investments listed above to be higher than the 2023-2027 period primarily due to evolving IESO planning assumptions and higher and sustained inflationary pressures experienced by Hydro One relative to the inflation assumptions embedded in its prior rebasing application (EB-2021-0110), as described in SPF Section 1.8. Neither the inflation assumptions in the prior application, nor the OEB inflation factors have kept pace with the actual costs that Hydro One and other utilities have experienced during this period. Overall historic material cost escalation trends are described in SPF Section 1.8.3, including transmission and distribution poles, conductors, cables and wires, power transformers, and high voltage circuit breakers which have increased by 45%, 65%, 115%, 140% on average since 2020.

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Table B1 - Hydro One - Detailed Material Investment Costs ($M)

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[3]			
		Act/Fcst[4] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
	Projects														
T-SS-12.01	Windsor Lakeshore Transmission Line – Station Work	5.0	10.0	10.0	20.0	25.0	**0.0**	**65.0**	P	70.0	2032	-	-	-	-
T-SS-12.02	North of Dryden Transmission Reinforcement	15.6	22.0	27.0	27.5	27.9	0.0	**104.4**	P	120.0	2031	-	-	-	-
T-SS-12.03	Wellington TS: Build new 500 kV/230 kV Station	41.6	52.0	74.3	79.0	17.7	0.0	**223.0**	P	264.6	2031	-	-	-	-
T-SS-12.04	115 kV Upgrades (B5/6C, D7/9F, F11/12C)	30.6	20.8	0.0	0.0	0.0	0.0	**20.8**	P	51.4	2028	-	-	-	-
T-SS-12.05	D6V/D7V - Upgrade circuits out of Detweiler	1.9	7.7	4.9	0.0	0.0	0.0	**12.7**	P	14.6	2029	-	P	4.5	2028
T-SS-12.06	Kanata Area Transmission Reinforcement	1.0	4.2	10.8	45.8	74.9	76.4	**212.2**	P	244.3	2033	-	P	62.2	2030
T-SS-12.07	Orleans TS: Provide second 230 kV supply	62.7	38.8	14.1	0.0	0.0	0.0	**52.9**	E	115.6	2029	-	P	49.0	2028
T-SS-12.08	Merivale TS Split M1R-L2M	0.0	0.6	2.7	8.8	18.6	8.6	**39.3**	P	39.3	2032	-	-	-	-
T-SS-12.09	Brockville TS - Install new Capacitor Bank	1.0	4.0	4.0	0.3	0.0	0.0	**8.3**	P	9.3	2030	-	-	-	-

[3] "Prior Project Forecast" refers to the forecast project total and in-service date when Hydro One revised the capital 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.

ISD Ref.	Investment Name	Net Capital Investment							Project Forecast			Prior Project Forecast[3]			
		Act/Fcst[4] 23-27	2028	2029	2030	2031	2032	28-32 Total	Type	Proj. Total	In-Service Year	ISD Ref.	Type	Prior Proj. Total	In-Service Year
T-SS-12.10	Manby x Riverside Jct 115 kV Line Upgrade	8.6	13.8	0.9	0.0	0.0	0.0	**14.7**	P	23.2	2028	-	-	-	-
T-SS-12.11	Uprate 230 kV QFW Circuits 14km – Beck x Abitibi Jct	2.7	24.3	32.8	0.0	0.0	0.0	**57.1**	P	59.8	2029	-	-	-	-
T-SS-12.12	Uprate 115 kV D9HS D10S 10km – Decew x Glendale	1.1	2.8	11.0	6.8	0.0	0.0	**20.6**	P	21.7	2030	-	-	-	-
T-SS-12.13	Meadowvale to Hurontario Transmission – Line	-	2.0	25.0	20.0	20.0	20.0	**87.0**	P	100.0	2033	-	-	-	-
T-SS-12.14	Hurontario SS Reconfiguration – Station	-	2.0	8.0	8.0	8.0	10.0	**36.0**	P	40.0	2033	-	-	-	-
T-SS-12.15	Unallocated expenditures	-	10.0	20.0	30.0	40.0	50.0	**150.0**	-	-	-	-	-	-	-

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T-SS-13	MITIGATING SHORT-CIRCUIT LIMITATIONS AT HYDRO ONE STATIONS TO ENABLE RESOURCE CONNECTIONS
Primary Trigger:	IESO Long-Term Energy Supply Procurement
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness

Net Capital Expenditures:

($M)	2028	2029	2030	2031	2032	Total
Hydro One	14.9	16.8	16.9	10.0	5.0	63.6

Summary:

This investment is required in response to a request letter from the IESO to accommodate the connection of resources that have already been procured by the IESO through the Long-Term 2 Energy Supply (Window 1) Request for Proposals (RFP) process (LT2(e-1) RFP), and the Long-Term 2 Capacity Services (Window 1) RFP process (LT2(c-1) RFP). Additionally, work is required at two stations due to resources procured by the IESO's Long-Term 1 RFP process (LT1 RFP, collectively the LT RFPs).

The IESO issued a letter to Hydro One dated August 6, 2026, requesting that Hydro One prioritize and proceed with addressing the short-circuit limitations at 19 stations, including two needed to accommodate resources procured through the LT1 RFP where the limited capacity to connect resources in the West and Southwest zones was identified as part of the LT1 RFP process, and 17 stations needed to accommodate resources procured through the LT2(e-1) RFP and LT2(c-1) RFP.

The investment addresses a portfolio of medium voltage (MV) and high voltage (HV) stations whose short-circuit levels are impacted by specific resources procured by the IESO through the LT RFPs. Without this portfolio of investments, there is a risk that the resources may not be able to be connected.

1.0 INVESTMENT NEED

This investment is in response to the IESO's letter of August 6, 2026, and is necessary for Hydro One to accommodate the connection of resources that have already been procured by the IESO through the LT RFPs. The procurement of the resources, which the IESO considers to be necessary for Ontario, increases the fault levels at the identified stations. The investment will enable Hydro One to withstand higher fault levels at the identified stations so that the new generation resources can be connected. Due to the recent timing of the request from the IESO, the full and detailed scope of the work required at each of the affected stations has not yet been determined, but will be undertaken in accordance with the IESO's August 6, 2026 letter and developed through Hydro One's normal capital work program processes.

The need for short-circuit mitigation work at these stations was confirmed by Hydro One on June 19, 2026, following the IESO's issuance of results from the LT2 (Window 1) RFP processes and its 2025 NERC TPL-001-5.1 Planning Assessment, in consultation with the IESO.

The limitations arise because the short circuit levels at the stations are at or exceed the capability of existing equipment, or the stations have short-circuit levels that are at or which exceed the maximum fault levels prescribed in Appendix 2 of the Transmission System Code (TSC). The IESO's procurement of new generation resources in the LT RFP processes is expected to further increase fault levels at the identified stations. This investment enables Hydro One to mitigate the increased fault levels at the affected stations.

2.0 INVESTMENT DESCRIPTION

The scope of individual station investments may include replacement of lower rated switchgear with higher rated switchgear, installation of bus tie reactors, installation of surge capacitors, bypassing of current limiting reactors and / or reconfiguration of station connections, all of which are typical solutions used in response of increased short-circuit levels.

This investment is non-discretionary. First, Hydro One considers the investment to be non-discretionary in nature on the basis that Hydro One received a request from the IESO to prioritize and proceed with addressing the identified system needs related to the modification of Hydro One's transmission system in a manner that the IESO determined was necessary to accommodate resources that it procured. Second, as noted above, this investment is necessary to maintain compliance with maximum fault levels prescribed in Appendix 2 of the TSC. Failure to undertake this investment would have near-term reliability and safety implications and constrain Hydro One's ability to connect IESO-procured resources.

The ability to commence each station investment will depend on obtaining all necessary regulatory and environmental approvals. A System Impact Assessment and Customer Impact Assessment may also be carried out, if required, for each investment to ensure that there are no adverse impacts on the transmission system or other transmission connected customers.

3.0 OUTCOMES

3.1 OEB RRF OUTCOMES

This investment will address specific needs at the affected stations as identified through fault level studies conducted by Hydro One.

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	• Ensure reliable supply from affected stations. • Enable connection of generation customers.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission Licence and the TSC to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth. • Accommodate the connection of generation resources, which were procured by the IESO through competitive processes pursuant to Directives from the Minister of Energy and Mines.

4.0 EXPENDITURE PLAN

This investment is non-discretionary on the basis that Hydro One received a request from the IESO to prioritize and proceed with addressing the identified system needs related to the modification of Hydro One's transmission system in a manner that the IESO determined was necessary to accommodate resources that it procured.

The investment costs will be recovered from the appropriate rate pool determined on a project-by-project basis in accordance with the TSC. The investment's actual in-service costs will be included in the rate base when the individual station investments go into service.

The individual station investment needs and scopes have not yet been defined due to the timing of the IESO letter dated August 6, 2026. As such, the cost of the investment presented is preliminary and derived from a high-level and conservative estimate based on typical mitigation strategies for short-circuit limitations. The forecast investment reflects the minimum level of capital expenditure that Hydro One expects will be required to address the needs identified in the IESO letter during the 2028-2032 planning period. As planning and development proceed and the scope of the investment is further defined, Hydro One will update this Application to reflect any material changes to forecast capital expenditures if required.

As proposed in Exhibit G-01-03 Section 3.1, the Externally Driven Transmission Projects Variance Account will record the revenue requirement impact of variances between the in-service additions embedded in Hydro One's approved revenue requirement relating to this investment and the actual in-service additions for this investment over the 2028-2032 period.

Table 2 below summarizes Hydro One's actual and forecast capital expenditures for the 2023-2027 prior period and the forecast capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One Investment Expenditures[1]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	15.0	17.0	17.0	10.0	5.0	64.0
Less Removals	0.2	0.2	0.1	0.0	0.0	0.4
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Capital Expenditures	**14.9**	**16.8**	**16.9**	**10.0**	**5.0**	**63.6**

This investment is expected to be completed in alignment with the IESO's in-servicing timelines for the resources procured in LT1 and LT2 (W1), as applicable. The forecast project total is expected to be $66.6M, reflecting the anticipated scope of work for the number of anticipated projects. The annual expenditure profile was developed based on the August 6, 2026 IESO letter timing, forecasted release date, the required in-service date, and a typical project work flow sequence (estimation, procurement, construction, and commissioning) informed by experience from past projects, including those arising from previous IESO generation procurements. Accordingly, expenditures are assumed to be minimal in 2026, reflecting preliminary estimation activities; increasing in 2027 to support detailed estimating and early procurement. Hydro One expects to incur $3.0M prior to 2028, with the majority of expenditures occurring during the main construction period from 2028-2032.

5.0 ALTERNATIVES

This investment will fund work that will enable the connection of generation projects for which contracts have been awarded by the IESO in its LT RFP procurement initiatives. Alternatives, if any, will be identified and considered as part of the planning process.

6.0 EXECUTION RISK AND MITIGATION

No major execution risk is expected. However, there is potential for normal project risks that may affect the timely completion of the investments, such as the outage availability that is required for the work to be executed. This risk will be mitigated by setting a schedule that aligns with outage availability.

[1] Figures presented in the tables may not sum to the totals shown due to rounding.

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T-SS-14	**BOWMANVILLE SS LOOP REPLACEMENT**
Primary Trigger:	Reliability
OEB RRF Outcomes:	Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	0.2	0.3	11.0	16.9	2.3	30.8

Summary:

This investment is required to replace eight existing 500 kV loop connections between Bowmanville Switching Station (SS) and Darlington Generating Station (GS) with eight motorized disconnect switches. One of the primary drivers for this investment is to improve the reliability and operability of the bulk transmission system at this important location on the transmission system, which is the point of supply from Darlington GS. Another significant driver for this investment is to reduce the safety risks associated with manual operation of the 500 kV loop connections.

The existing loop configuration has been in service for many years. Hydro One has identified these 500 kV loops as operational anomalies that require manual opening and closing, which presents increased safety risk to field personnel and operational constraints during switching activities. Replacing these loops with motorized disconnect switches will enable remote operation, reduce the need for manual intervention, minimize outage time and enhance system reliability.

Hydro One is obligated to operate and maintain its transmission assets safely and reliably in accordance with its Transmission Licence and the Transmission System Code. Failure to proceed with this investment would limit operational flexibility and continue to expose workers to avoidable safety risks at a critical interface with Darlington GS.

1.0 INVESTMENT NEED

This investment is required to address reliability and safety concerns associated with the continued use of manually operated 500 kV loop connections at Bowmanville SS. The relevant facilities form part of the Bulk Electric System and support a critical generating station interface. The existing configuration limits operational flexibility and delays switching actions required during outages, maintenance activities, or system contingencies. Moreover, manual operation at this voltage level exposes field crews to elevated safety risks and increases the potential for operational errors during switching activities. Replacement of these assets with motorized disconnect switches will allow remote operation and faster, safer switching.

Hydro One is obligated under its Transmission Licence to ensure the safe and reliable operation of the transmission system. Proceeding with this investment supports these obligations and aligns with Hydro One's asset management and safety objectives.

2.0 INVESTMENT DESCRIPTION

This investment involves replacing eight existing manually operated 500 kV loop connections between Bowmanville SS and Darlington GS with eight motorized disconnect switches. The existing 500 kV loop connections are high-voltage conductors that form part of the transmission interface between Bowmanville SS and Darlington GS and currently require crews to travel to site to perform switching operations manually. The proposed motorized disconnect switches provide the same electrical function but can be operated remotely from Hydro One's control centre, improving operational flexibility, reducing response times during outages and contingencies, and minimizing worker exposure to switching-related safety risks.

The scope of work includes:

- Removal of eight existing 500 kV loop connections;
- Installation of eight new motorized 500 kV disconnect switches;
- Integration with station protection, control, and Supervisory Control and Data Acquisition (SCADA) systems; and
- Associated civil, electrical, and commissioning activities.

The IESO's System Impact Assessment and Hydro One's Customer Impact Assessment are expected to be completed by Q3 2028 to confirm that this investment will not adversely affect the reliability of the IESO-controlled grid, or service to other transmission connected customers. No adverse impacts to the IESO-controlled grid or other transmission connected customers are anticipated as a result of this investment at this time.

3.0 OUTCOMES

This investment will improve the reliability, operational effectiveness and safety of the 500 kV transmission interface between Bowmanville SS and Darlington GS.

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits as a result of the investment in accordance with the OEB Renewed Regulatory Framework.

Table 1 - Outcome Summary

Operational Effectiveness	• Improve switching efficiency and system operability. • Reduce outage durations and operational risks.
Public Policy Responsiveness	• Minimize worker exposure to switching-related safety risks.

4.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's forecast capital expenditures for the 2028-2032 planning period.

Table 2 - Hydro One - Investment Expenditures[1]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	0.2	0.3	11.0	16.9	2.3	30.8
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	**0.2**	**0.3**	**11.0**	**16.9**	**2.3**	**30.8**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.

This investment is expected to be placed in-service in 2032 at a forecast project total of $30.8M net.

5.0 ALTERNATIVES

ALTERNATIVE 1: CONDITION-BASED REPLACEMENT OF EXISTING LOOPS

Under this alternative, the existing manually operated 500 kV loops would remain in service until they are identified for replacement based on asset condition assessment. This option was considered and rejected, as it does not improve operational flexibility or reliability, or address safety risks to field personnel.

ALTERNATIVE 2: REPLACE 500 KV LOOPS WITH CIRCUIT BREAKERS

This alternative involves replacing the existing manually operated 500 kV loops at Bowmanville SS with circuit breakers. While this option would provide comparable operational flexibility and remote operability, it was not selected because it would require significantly higher capital investment, estimated at close to $90.0M, compared to $30.8M for the installation of motorized disconnect switches. Accordingly, this alternative was rejected.

ALTERNATIVE 3: REPLACE 500 KV LOOPS WITH MOTORIZED DISCONNECT SWITCHES (RECOMMENDED)

This alternative involves replacing the existing manual 500 kV loops with motorized disconnect switches at Bowmanville SS.

This option eliminates the need for manual switching, enhances system reliability and operational flexibility, and minimizes safety risks to field personnel. It represents the most effective means of mitigating identified risks.

6.0 EXECUTION RISK AND MITIGATION

Hydro One does not anticipate any major execution risks. Potential project risks include outage availability, equipment delivery timelines, and coordination with station operations. These risks will be mitigated through early outage planning, procurement scheduling, and coordination with system operations and stakeholders. Detailed outage planning will be

completed in coordination with Ontario Power Generation (OPG), the IESO, and Hydro One System Operations. The work is expected to be sequenced to maintain system reliability and minimize impacts to generation output.

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T-SS-16	**WAASIGAN STATION WORK**
Primary Trigger:	Bulk Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Net Capital Expenditures:

($M)	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Hydro One	15.2	0.0	0.0	0.0	0.0	15.2

Summary:

This investment is required to complete and close-out the stations work associated with the Waasigan Transmission Line Project. The majority of the stations work is expected to be completed prior to 2028; the forecast capital expenditures for the 2028-2032 period are for the resolution of outstanding issues not addressed during execution, and formal project close-out, each as required in relation to the stations work.

The Waasigan Transmission Line Project is expected to provide the required increase in supply capacity to support future load growth and maintain reliability for the Northwest region in the long-term as identified by the IESO through its Northwest Ontario bulk planning activities carried out through 2022 and 2023.

The need to implement this investment emerged in May 2022 when the IESO identified a near-term requirement for additional transmission capacity in Northwestern Ontario driven primarily by anticipated mining-related load growth and recommended that Phase 1 proceed while continuing to assess Phase 2. The project's ultimate scope and timing were confirmed in April 2023 when the IESO established the need for Phase 2 following an updated assessment of demand forecasts, mining outlooks and alternatives.

Hydro One is obligated to provide facilities required to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth in accordance with its Transmission License and the Transmission System Code.

1.0 INVESTMENT NEED

This investment is required to complete the station work for the Waasigan Transmission Line Project[1], including post-in-service activities, resolution of outstanding issues not addressed during execution and formal project close-out.

The Waasigan Transmission Line Project is required to provide 350 MW of additional transfer capacity to support forecast load growth and reliability in Northwestern Ontario and consists of a new double-circuit 230 kV line between Lakehead TS and Mackenzie TS (Phase 1), a new single-circuit 230 kV line between Mackenzie TS and Dryden TS (Phase 2), and associated station expansions and reconfigurations to incorporate the new lines into the network.

Pursuant to a 2013 Order in Council (OIC 1701/2013), Hydro One's transmission licence was amended to require Hydro One to develop and seek approvals for the NWBTL in accordance with the scope and timing recommended by the IESO.

Although the Waasigan Transmission Line Project was contemplated through earlier provincial planning processes, the implementation need emerged in May 2022 when the IESO updated its demand forecast for Northwestern Ontario and identified a near-term requirement for additional transmission capacity, primarily driven by anticipated mining-sector growth. The IESO subsequently recommended that Phase 1 proceed with an in-service date as close to the end of 2025 as possible while continuing to assess the timing and necessity of Phase 2. As a result, the ultimate scope and timing of the project remained uncertain and was not included in the 2023-2027 post-settlement investment plan.

In April 2023, following an updated assessment to include revised demand forecasts, mining outlooks, cost information, and analysis of alternatives, the IESO confirmed the need for Phase 2 and recommended that it proceed as soon as practical following Phase 1. This recommendation established the full project scope and implementation plan. Hydro

[1] The new transmission lines are anticipated to be owned by Waasigan Transmission LP; due to the affiliate nature of the transmission lines, the costs have been excluded from the application.

One subsequently advanced engineering, procurement, regulatory approvals, and construction activities, including obtaining leave to construct approval in April 2024.

The expenditures included in this ISD relate to the final completion of the component of the project following the expected in-service dates for Phases 1 and 2.

2.0 INVESTMENT DESCRIPTION

As described in TSP Section 2.11, once construction is complete, projects enter the commissioning phase and finally the project closure phase. During these phases, Hydro One validates that newly installed assets are safe, functional, and ready for service, updates asset records and drawings, confirms that project objectives and stakeholder deliverables have been achieved and issues final payments on outstanding purchase orders.

In 2028, Hydro One expects to complete the remaining close-out activities for the station work for this project, including resolution of outstanding deficiencies, final contract settlements and holdback payments, updates to asset records and as-built drawings, and project completion documentation.

3.0 OUTCOMES

Overall, the Waasigan Transmission Line Project provides a minimum of 350 MW of westbound transfer capacity from Lakehead TS into / out of Mackenzie TS and Moose Lake TS. The stations work associated with the Waasigan Transmission Line Project enables the transmission lines associated with the project to be connected to Hydro One's transmission system. The capital expenditures included in this ISD will allow Hydro One to bring the stations work to final completion, including the resolution of outstanding issues not addressed during execution, and formal project close-out of the scope outlined above in relation to stations work.

3.1 OEB RRF OUTCOMES

Table 1 presents anticipated benefits pertaining to the completion of station work in accordance with the OEB Renewed Regulatory Framework (RRF).

Table 1 - Outcome Summary

Customer Focus	• Meets customer load forecast in the northwest region
Operational Effectiveness	• Maintain reliability while increasing the transfer capability in the area
Public Policy Responsiveness	• Comply with the IESO request to construct Waasigan Phase 1 and Phase 2 to provide sufficient capacity for demand growth in Northwest Ontario, including connection of remote communities.

4.0 EXPENDITURE PLAN

Table 2 summarizes Hydro One's forecast capital expenditures for the 2028-2032 rate period.

Table 2 - Hydro One – Investment Expenditures[2]

($M)	2028	2029	2030	2031	2032	Total 28-32
Gross Capital Expenditures	15.2	0.0	0.0	0.0	0.0	15.2
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	**15.2**	**0.0**	**0.0**	**0.0**	**0.0**	**15.2**

The forecast Project Total for the stations work, including Phase 1 (expected to be placed in-service in 2026) and Phase 2 (expected to be placed in-service in 2027) is $200.7M. Of this, Hydro One expects to substantially complete construction of the station work for Phases 1 and 2 prior to 2028, at a total cost of $185.5M.[3] The current ISD corresponds to the remaining $15.2M, which Hydro One expects to incur in 2028.

As proposed in Exhibit G-01-03, Section 3.1, the Externally Driven Transmission Projects Variance Account will record the revenue requirement impact of variances between the in-service additions embedded in Hydro One's approved revenue requirement relating to this investment and the actual in-service additions for this investment over the 2028-2032 period.

[2] Figures presented in the tables may not sum to the totals shown due to rounding.
[3] In the historic and bridge period, expenditures under this investment were included in the System Renewal category.

5.0 ALTERNATIVES

No alternatives were considered by Hydro One, as this investment relates to post-in-service and close out activities for stations work that Hydro One expects to substantially complete before 2028 in response to an Order in Council and corresponding condition in its Transmission Licence requiring Hydro One to undertake that stations work in accordance with the scope and timing recommended by the IESO. The remaining activities are required to bring the stations work to final completion in 2028.

6.0 EXECUTION RISK AND MITIGATION

No new material risks and mitigations have been identified as the project is in its final stages with only tasks left that are administrative in nature.

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